Ludlow Electric Department

2022 Integrated Resource Plan

Vermont Public Power Supply Authority

Filed with the Public Utility Commission

EXECUTIVE SUMMARY

The Village of Ludlow has operated an electric utility system since 1900 in the south-central part of Vermont, in an area where weather events, especially in recent years, have been both challenging and at times highly localized. Ludlow Electric Light Department's (LED) service territory encompasses the Village of Ludlow, and parts of the towns of Ludlow, Plymouth, Proctorsville, and Mt. Holly. LED remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. As a small municipal utility LED is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

LED's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up about 80% of the customer mix while accounting for about a third of LED's retail kWh sales. Four large commercial customers (less than 1%) make up almost 40% of retail usage with the remaining 30% of retail sales going to small commercial and public authority customers.

Consistent with regulatory requirements, every 3 years LED is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan, or IRP) for provision of energy services to its Vermont customers. LED's 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

LED 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 LED'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. Forecasted 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 very modest projected load growth in the longer term.

While no significant change in the demand associated with LED's largest customers is currently anticipated, the potential does exist. With 40% of LED's energy requirements concentrated across 4 large commercial customers, LED monitors the plans of these large customers to anticipate necessary changes to the existing resources plan and system infrastructure. In the case of a significant expansion by one or more customers, detailed engineering studies may be needed to identify necessary system upgrades.

ELECTRICITY SUPPLY

LED'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 sources.

When considering future electricity demand, LED seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. LED 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. LED 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 resource contributes to meeting Renewable Energy Standard goals. Generation may have a role to play in the future portfolio for reliability purposes. As battery storage technology matures and proves economically feasible LED sees potential for storage to play an important load management role and to enhance the local impact of distributed generation. LED is currently working with development partners to explore the siting of a significant storage facility, as well as a large solar facility, within its service territory.

RESOURCE PLANS

Looking ahead to evaluating major policy and resource acquisition decisions, LED 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 LED 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.

LED faces three major energy resource decisions, affecting about 80% of its power supply, over the 2023 – 2042 period covered by this IRP. The first of these involves the need to cover the roughly 40% of LED's energy requirement that is currently covered by a contract expiring late in 2022. Options being evaluated by LED include annual market purchases or purchasing a longer term fixed-price contract for bundled hydro energy including Tier I RECs.

The second group of major resource decisions faced by LED 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 representing about 10% of LED's energy requirements. The second of these decisions relates to the replacement of the Brookfield Hydro contract, which provides about 30% of LED's energy needs and 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 off-shore wind.

LED notes both of these decisions are subject to uncertainty arising from potential changes in RES requirements.

The third major resource decision coincides with the ultimate 2031 expiration of the Fitchburg Landfill Gas contract (assuming it was extended in 2025) which represents about 10% of LED's energy requirements. Because this contract provides premium 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 LED holds entitlements in capacity resources that equal expected requirements based on demand, no capacity related resource decisions are anticipated.

RENEWABLE ENERGY STANDARD

LED is subject to the Vermont Renewable Energy Standard which imposes an obligation for LED 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. LED' 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 LED'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 LED receives credits toward its TIER III obligation. LED will be exploring custom electrification opportunities with some of its larger customers, although no proposal has yet taken shape. More detail regarding LED's plans to meet its TIER III obligation is available in Appendix A to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

LED has a compact service territory as a result of being a small, municipal-owned electric utility and has consistently pursued upgrade initiatives each year in order to maintain a reliable and efficient system. LED's distribution system consists of approximately 65 miles of distribution line operating at 12.5 kV, with three substations connected to the Green Mountain Power (GMP) transmission system.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, LED 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 LED and its customers. LED is currently engaged, with VPPSA, in the final stages of a multi-phased process that is anticipated to result in implementation of an AMI system beginning in late 2023. LED 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 LED's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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

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INTRODUCTION

The Village of Ludlow has operated an electric utility system since 1900 in the south-central part of Vermont, in an area where weather events, especially in recent years, have been both challenging and at times highly localized. Ludlow Electric Light Department's (LED) service territory encompasses the Village of Ludlow, parts of the towns of Ludlow, Plymouth, Proctorsville, and Mt. Holly and can be seen on the Vermont Utility Service Territory map found on the next page. LED remains guided by Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. Well-established practices keep LED operating safely, efficiently, and reliably.

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.

LED 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:

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

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

SYSTEM OVERVIEW

LED's distribution system serves a mix of residential and commercial customers, the largest of which is Okemo Mountain Resort (Okemo). Okemo is the largest driver of LED's service load. In 2021 LED's noncoincident system peak demand in the winter months was 13,459 kW and 8,823 kW during the summer months, making 2021 a new historical peak year for both winter and summer peaks. LED is a winter peaking utility. Annual retail energy sales for 2021 were 50,773,314 kWh. Up until 2021, the historical peak in the winter was 13,388 kW in February of 2020 and the historical peak in the summer was 8,352 kW during the summer of 2018. LED is connected to Green Mountain Power's (GMP) 46 KV transmission system. LED does not own any generation within its service territory, supplying electricity to its customers through contractual entitlements to power plants and wholesale market contracts throughout the region.

The following tables show LED's number of customers, retail sales and system peaks for the past five years.

Table 1: LED's Retail Customer Counts

Data Element	2017	2018	2019	2020	2021
Residential	3,034	3,045	3,090	3,048	3,037
Commercial & Industrial	708	709	724	762	759
Street Lighting	3	3	3	9	11
Total	**3,745**	**3,757**	**3,817**	**3,819**	**3,807**
YOY	2%	0%	2%	0%	0%

Table 2: LED's Retail Sales kWh

Data Element	2017	2018	2019	2020	2021
Residential	15,978,156	17,141,759	16,822,880	18,985,814	17,416,982
Commercial & Industrial	31,093,932	37,089,968	38,191,636	31,215,803	33,175,836
Street Lighting	348,276	347,690	324,996	319,162	180,496
Total	**47,420,364**	**54,579,417**	**55,339,512**	**50,520,779**	**50,773,314**
YOY .	3%	15%	1%	-9%	0%

As shown in Table 2, there was a significant reduction in street lighting kilowatt-hour retail sales in 2021, compared to prior years, due to switching to more efficient LED lighting.

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

Data Element	2017	2018	2019	2020	2021
Peak Demand kW	12,242	13,058	13,073	13,388	13,469
Peak Demand Date	01/13/17	12/18/18	12/19/19	02/15/20	12/20/21
Peak Demand Hour	19	16	15	11	11

[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 LED's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION

This chapter describes LED'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 LED's power supply costs and cost of service.

ACTION PLAN

This chapter outlines specific actions the LED expects to take as a result of this IRP.

APPENDIX

The appendix includes a series of supporting documents and reports.

GLOSSARY

ELECTRICITY DEMAND

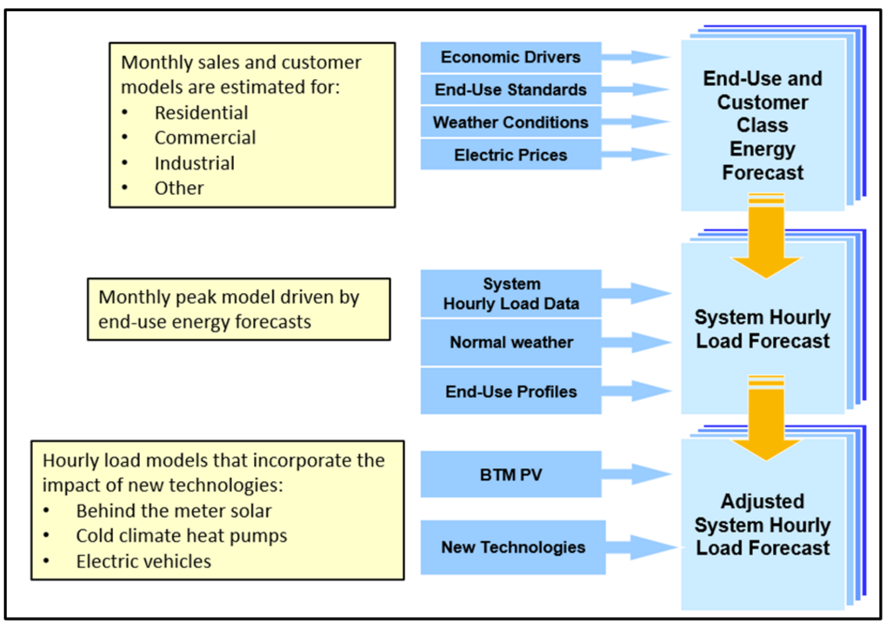
I. ELECTRICITY DEMAND

ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast LED'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, electric vehicles, and net-metered Solar are shared with the LRTP.

The 2022 long-term forecast includes energy and peaks that are 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 1.[3]

Figure 1: Forecasting Process



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

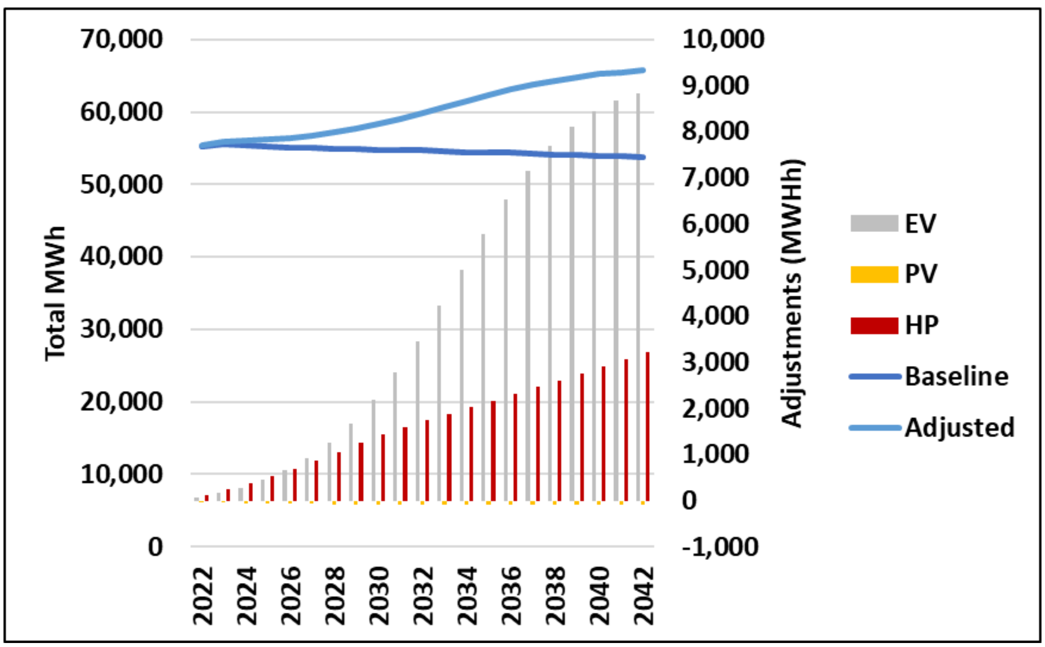
ENERGY FORECAST RESULTS

Table 4 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 0.1% per year. After making adjustments for electric vehicles (EV), net metered solar (NM PV) and heat pumps (HP) the Adjusted Forecast increases by 0.9% per year. The Adjusted Forecast is the result of high CAGRs for HPs (18%) and EVs (27.4%). Figure 2 shows how the adjustments impact the baseline trend.

Table 4: Adjusted Energy Forecast (MWh/Year)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	55,216	70	-15	118	55,388
2027	5	54,997	917	-74	869	56,709
2032	10	54,698	3,464	-87	1,739	59,814
2037	15	54,255	7,161	-92	2,459	63,782
2042	20	53,743	8,829	-97	3,220	65,695
CAGR		-0.1%	27.4%	9.7%	18.0%	0.9%

Figure 2: 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 3,000 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: 1.7% per year. This growth rate results in a 40% increase over 2022 electricity use.

Table 5: Energy Forecast – High Case (MWH)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	55,216	140	-15	236	55,576
2027	5	54,997	1,834	-74	1,739	58,495
2032	10	54,698	6,928	-87	3,478	65,017
2037	15	54,255	14,321	-92	4,918	73,402
2042	20	53,743	17,658	-97	6,440	77,744
CAGR		-0.1%	27.4%		18.0%	1.7%

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 0.4% per year.

Table 6: Energy Forecast - Low Case (MWH)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	55,216	70	-15	118	55,388
2027	5	54,997	458	-74	435	55,816
2032	10	54,698	1,732	-87	870	57,212
2037	15	54,255	3,580	-92	1,230	58,972
2042	20	53,743	4,414	-97	1,610	59,670
CAGR		-0.1%	23.0%		14.0%	0.4%

PEAK FORECAST RESULTS

Table 7 and Table 8 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 nearly flat and only changes by +/-0.3% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 0.7-1.4% per year. Because of Okemo Mountain, the winter peak is much larger than the summer peak, and the timing of the peak hour is expected to be stable in the early evening hours.

Table 7: Summer Peak Forecast (MW)

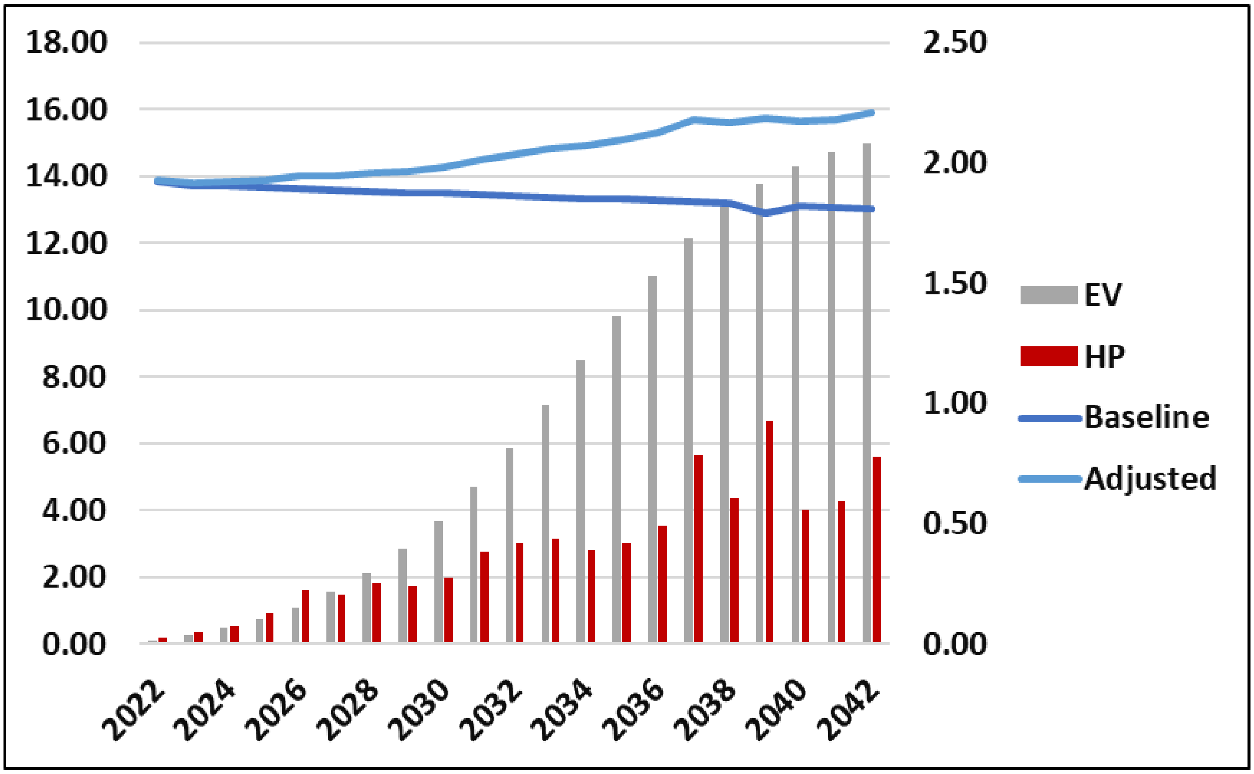
Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	8.2	0.0	0.0	0.0	8.2
2027	5	8.3	0.1	0.0	0.1	8.4
2032	10	8.3	0.7	0.0	0.2	9.1
2037	15	8.6	1.4	0.0	0.2	10.2
2042	20	8.6	1.8	0.0	0.3	10.7
CAGR		0.3%	34.1%		17.8%	1.4%

Table 8: Winter Peak Forecast (MW)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	13.8	0.0	0.0	0.0	13.9
2027	5	13.6	0.2	0.0	0.2	14.0
2032	10	13.4	0.8	0.0	0.4	14.7
2037	15	13.2	1.7	0.0	0.8	15.7
2042	20	13.0	2.1	0.0	0.8	15.9
CAGR		-0.3%	27.6%		18.1%	0.7%

The size of the electrification adjustments can be seen in Figure 3, which shows the winter peak forecast net of adjustments. The Adjusted Forecast exceeds the Baseline Forecast immediately as a result of high CAGRs for HPs and EVs.

Figure 3: 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 immediately, and by 2042, the peak reaches 18.7 MW, which is 20% higher than in the reference case.

Table 9: Winter Peak Forecast – High Case (MW)

Year	Peak Hour	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	18	13.8	0.0	0.0	0.1	13.9
2027	18	13.6	0.4	0.0	0.4	14.4
2032	18	13.4	1.6	0.0	0.8	15.9
2037	18	13.2	3.4	0.0	1.6	18.2
2042	18	13.0	4.2	0.0	1.6	18.7
CAGR		-0.1%	27.6%		18.1%	1.5%

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 good 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 10 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 255 MWH/Year of new electric loads is in reasonable alignment with the heat pump and electric vehicle adjustments in Table 5, which shows a 190 MWH increase in electric loads in 2022 due to these technologies.

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

Table 10: Program Year 2022 Tier III Measures & Their Expected Impact on Load

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
Electric Vehicle - New	5	2.8	14
Electric Vehicle - New, Income Qualifying	2	2.8	6
Electric Vehicle Used	1	2.8	3
PHEV - New	1	1.7	2
PHEV- New, Income Qualifying	2	1.7	3
PHEV - Used	1	1.7	2
Heat Pump - ductless	50	3.4	168
Heat Pump - ductless, Weatherized	2	3.4	7
Heat Pump - ductless, Income Qualified	2	3.4	7
Integrated Controls (with Heat Pump)	2	3.4	7
Ground Source Heat Pump	1	3.4	3
WBHP - Ducted	5	4.2	21
WBHP - Air to Water	1	4.2	4
Heat Pump Water Heater	4	1.0	4
Golf Carts	6	0.8	5
Residential Lawn Mower	3	0.009	0
Total	**88**		**255**

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 11: 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 11. For devices that are 1.5 kW and smaller, the fees are 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 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, LED'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.

LED presently has about eleven 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. For example, a 500 kW net metered solar project built in 2023 would increase the base of installed, net metered capacity on the system (which was 227 kW as of March 2022) by over 200% 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 LED's largest customers, Okemo Mountain and Magris Talc both represent uncertainties to the load forecast. A major increase or decrease in operations or a change in physical infrastructure could impact the utility. For example, Okemo is considering an investment in electric water pumps for its snow making operations. This would replace diesel fuel as the pumping energy, and create a significant new load during the winter months. This project remains in the early planning stages, and LED is actively collaborating with Okemo to manage and minimize the impacts on the distribution system.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

LED'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 LED 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 LED'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: 26.3% (1.26 MW), PPA
- Products: Energy, capacity
- End Date: 6/30/39
- Notes: The contract does not include the environmental attributes and appears as system mix in the summary table.

3. Fitchburg Landfill

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 17.035%, PPA
- Products: Energy, capacity, renewable energy credits (MA I)
- End Date: 12/31/31

5. Hydro Quebec US (HQUS)

- Size: 212 MW
- Fuel: Hydro
- Location: Quebec
- Entitlement: 0.205%, 0.435 MW, PPA
- Products: Energy, renewable energy credits (Quebec system mix)
- End Date: 10/31/38

6. Kruger Hydro

- Size: 6.7 MW
- Fuel: Hydro
- Location: Maine and Rhode Island
- Entitlement: 19.29%, 1.29 MW, PPA
- Products: Energy, capacity
- End Date: 12/31/37
- Notes: LED has an agreement with VPPSA to purchase unit contingent energy and capacity from six hydroelectric generators. The contract does not include the environmental attributes and appears as system mix in the summary table.

7. Market Contracts

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

8. McNeil

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 2%, 1.08 MW, joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit
- Notes: As the joint-owner, VPPSA has agreements with the LED to pay for and purchase 1.2% of the unit's output.

9. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 3.31%, 0.1 MW (Niagara PPA), 0.997%, 0.001 MW (St. Law. PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 9/1/25 (Niagara), 4/30/32 (St. Lawrence)
- Notes: NYPA provides hydro power to LED under two contracts, which will be extended at the end of their term.

10. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 10% (4 MW) MW, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with LED to pay for and purchase 4.7% of the unit's output.

11. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.93280% (0.0093 MW), PPA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2026

12. Seabrook 2018-22 (NextEra)

- Size: 1,250 MW
- Fuel: Nuclear
- Location: Seabrook, NH
- Entitlement: 2.805 MW On-Peak, 2.112 MW Off-Peak (PPA)
- Products: Energy, capacity, environmental attributes (Carbon-free nuclear)
- End Date: 12/31/2022

13. Standard Offer Program

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas and micro-hydro
- Location: Vermont
- Entitlement: 0.9456% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies
- Notes: LED is required to purchase power from small power producers through the Vermont Standard Offer Program in 2020, in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with LED's pro rata share of Vermont's retail energy sales.

14. Stony Brook Station

- Size: 352 MW
- Fuel: Natural Gas, Oil
- Location: Ludlow, MA
- Entitlement: 0.5283%, (1.86 MW), PPA
- Products: Energy, capacity, reserves
- End Date: Life of unit

Table 12 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) are shown to show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed-price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits (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.

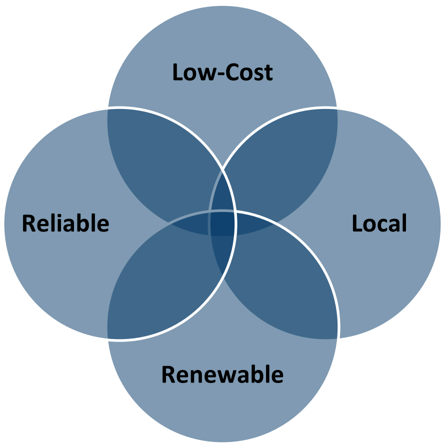
Table 12: Existing Power Supply Resources

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	1,787	3.1%	0.5	Intermittent	Fixed		6/30/39	No
Fitchburg Landfill	6,198	10.9%	0.7	Baseload	Fixed	✓	12/31/31	No
HQUS Contract	2,535	4.5%	0	7x16	Fixed + Inflation	✓	10/31/38	No
Kruger Hydro	4,101	7.2%	0.3	Run of River	Fixed		12/31/37	No
Market Contracts	8,401	14.8%	0	Must Take	Fixed		Varies	No
McNeil Facility	5,467	9.6%	1.0	7x16	Variable	✓	Life of Unit	Yes
NYPA Niagara Contract	3,771	6.6%	0.5	Baseload	Fixed	✓	9/1/25	Yes
NYPA St. Lawrence Contract	73	0.1%	0	Baseload	Fixed	✓	4/30/32	Yes
Project #10	39	0.1%	3.9	Peaking	Variable		Life of Unit	Yes
Ryegate Facility	1,738	3.1%	0.2	Baseload	Fixed	✓	10/31/26	No
Seabrook 2018-22 Purchase	21,340	37.5%	0	Baseload	Fixed		12/31/22	No
Standard Offer Program	1,205	2.1%	0	Intermittent	Fixed	✓	Varies	No
Stony Brook Station	279	0.5%	1.9	Peaking	Variable		Life of Unit	Yes
TOTAL RESOURCES	**56,934**	**100.0%**	9.0					

FUTURE RESOURCES

LED 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 4: Resource Criteria



1. **Low-Cost** resources reduce or stabilize electric rates.

- **Local** resources are located within LED'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 LED to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that LED may consider fall into three categories: 1.) Existing resources in Table 12, 2.) demand-side resources, and 3.) new resources that meet the criteria in Figure 4,.

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, LED 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 LED 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, LED will continue to welcome the work of the Efficiency Vermont (EVT) and SCVCA in its service territory. LED 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 LED continues to implement its energy transformation programs under RES.

VPPSA has a several of 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, LED will continue to monitor and evaluate new generation resources in the New England region.

3.1 WIND GENERATION (ON AND OFFSHORE)

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, LED will consider both on and offshore 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 LED’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, LED will continue to investigate solar developments both within its service territory and outside of it.

NET METERING

LED has 11 net-metered customers and an installed base of solar capacity of 232 kW. Over half of this capacity is from one 150 kW array. As a result, the growth in net-metered capacity is dominated by large systems.

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

Delorean is presently developing a series of storage sites, including two in Ludlow. The size of the project is approximately 4 MW and 12 MWH, and it is presently in the early planning stages.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Southern Windsor County Regional Planning Commission (SWCRPC), which was recently replaced by the Mount Ascutney Regional Commission (MARC), LED is part of a Regional Energy Plan that was approved by the SWCRPC Board of Commissioners in June 2018. The purpose of the plan is to give the SWCRPC greater input into local energy permitting decisions before the PUC, as explained in the Executive Summary:

> "The intent of this plan is to serve as the energy element of the Southern Windsor County Regional Plan per 24 V.S.A. §4348a(a)(3) as well as to meet the requirements of an "Enhanced Energy Plan" in accordance with 24 V.S.A. §4352. The Southern Windsor County Regional Planning Commission (SWCRPC) intends to submit this Plan to the Commissioner of Public Service for a determination of energy compliance, which would enable this document to receive "substantial deference" in Section 248 proceedings."[5]

This plan is presently before the PUC, and is expected to give SWCRPC "substantial deference" before the 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, LED will consult with the SWCRPC on resource decisions that involve potential siting of new resources in Vermont.

[5] Southern Windsor County Regional Energy Plan, Southern Windsor County Regional Planning Commission, June 25, 2018, Page iii

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, etc. 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
    1. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply (unit availability and hydro conditions).
2. Hydroelectric Adjustment
    1. 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
    1. **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.
    2. **External Transactions**: In the event that internal transactions cannot bring LED into the +/-5% range, external transactions are placed with power marketers, either directly or through a broker.
    3. **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 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. LED is currently considering an Energy Storage Service Agreement (ESSA) with VPPSA's storage development partner, Delorean Power. We also anticipate a bundled energy and Tier I REC PPA to help fulfill the Tier I RES requirements. Because long-term contracts are subject to PUC approval, the acquisition strategy is simply to negotiate the best terms and to make contract execution contingent on PUC approval.

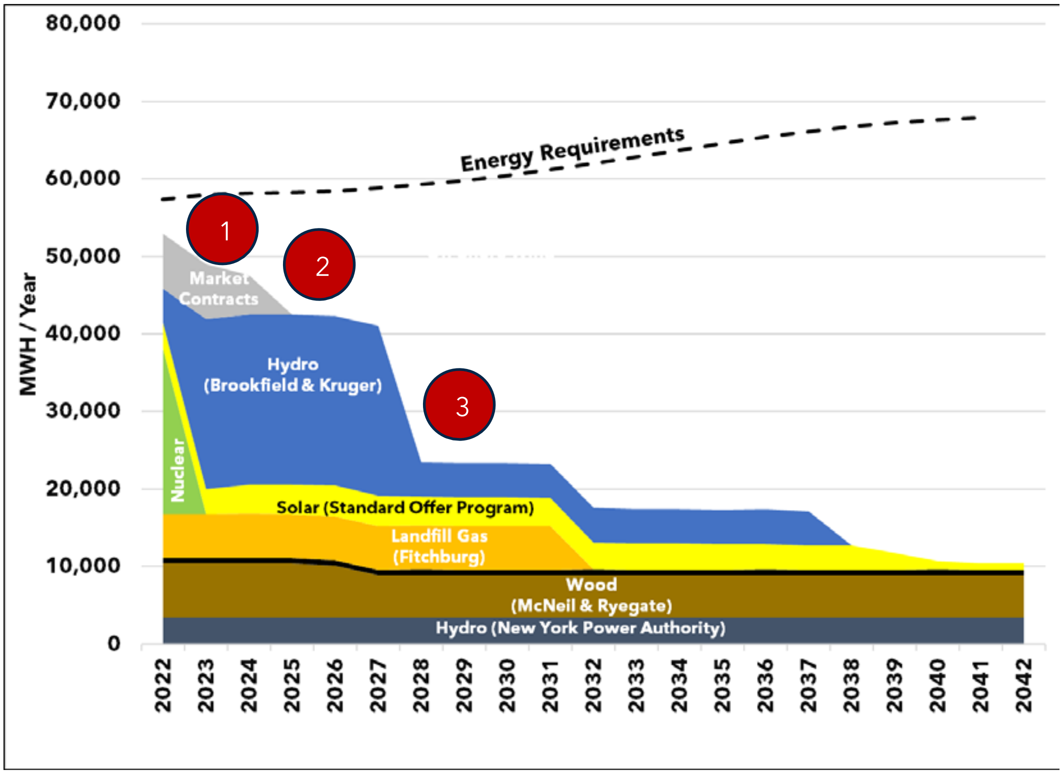
ENERGY RESOURCE PLAN

Figure 5 compares LED's energy supply resources to its adjusted load. There are three major resource decisions that, in total, will affect about 55% of LED'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 25% of LEDs energy supply.

DECISION 1: 2023

First, notice that 92% of LED's energy requirements are presently hedged by multi-year resources. When the NextEra 2018-2022 contract expires later this year, a 15% 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 5: 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 5. 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 5 by the decrease in the blue-shaded "Hydro" area. This contract supplies about 30% of LED'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.

LED 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 LED's Resource Criteria (Figure 4) 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 10% of LED'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 13 summarizes the energy resources decisions LED faces in the coming ten years.

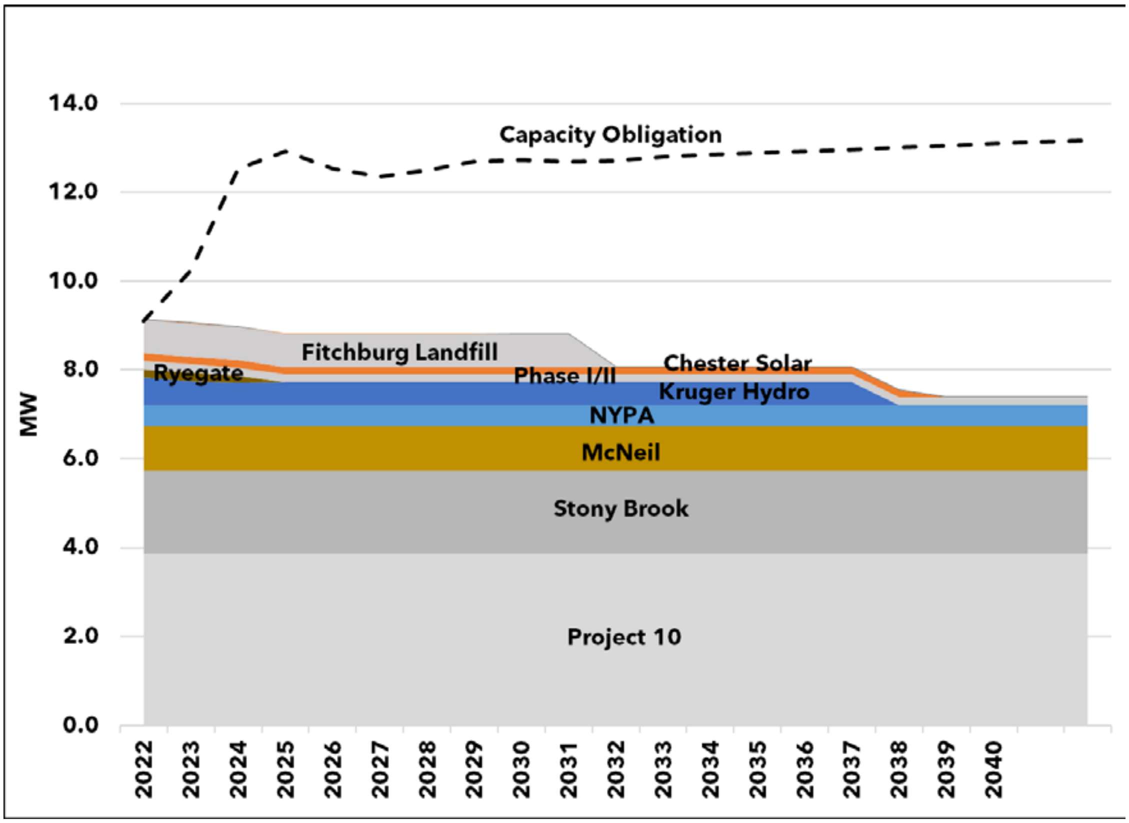
Table 13: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
NextEra 2018-2022	2023+	15%	Increase	None
Fitchburg Landfill Gas	2026 & 2031	10%	Neutral	Possible
Brookfield Hydro	2028+	30%	Increase	Yes

CAPACITY RESOURCE PLAN

Figure 6 compares LED's capacity supply to its capacity supply obligation (CSO). The CSO is equal to LED'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, three resources provide about 75% of LED's capacity. In 2023, Project 10 provides about 42%, Stonybrook provides 21% and McNeil provides another 11%.

Figure 6: Capacity Supply & Demand (Summer MW)



Notice that the CSO increases steeply in the first few years of the forecast. This is due to the COVID-19 pandemic, which suppressed LED's peak loads in 2020 and 2021. We forecast a return to pre-pandemic levels in 2022, which create the increase in the CSO. LED is about 70% hedged this decade, and with the potential addition of a 4 MW peak shaving battery, 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 LED's capacity costs, as explained in the next section.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because LED 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, LED 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 LED's 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, LED could receive up to a $14,000 payment or pay up to a $16,000 penalty during a one-hour scarcity event. This represents a range of plus or minus sixteen to 25% of LED's 2022 monthly capacity budget. However, such events occur infrequently (only once since 2018), and they frequently last less than one hour.

Table 14: 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	-$7,000	$3,600	$14,300
15,000	$5,500/MWH	-$10,000	$600	$11,200
20,000	$5,500/MWH	-$13,100	-$2,400	$8,200
25,000	$5,500/MWH	-$16,100	-$5,500	$5,200

[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

LED's obligations under the Renewable Energy Standard (RES) are shown in Table 15. Under RES, LED 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 7 in the next section.

Table 15: RES Requirements (% of Retail Sales)

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: (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 16: 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.

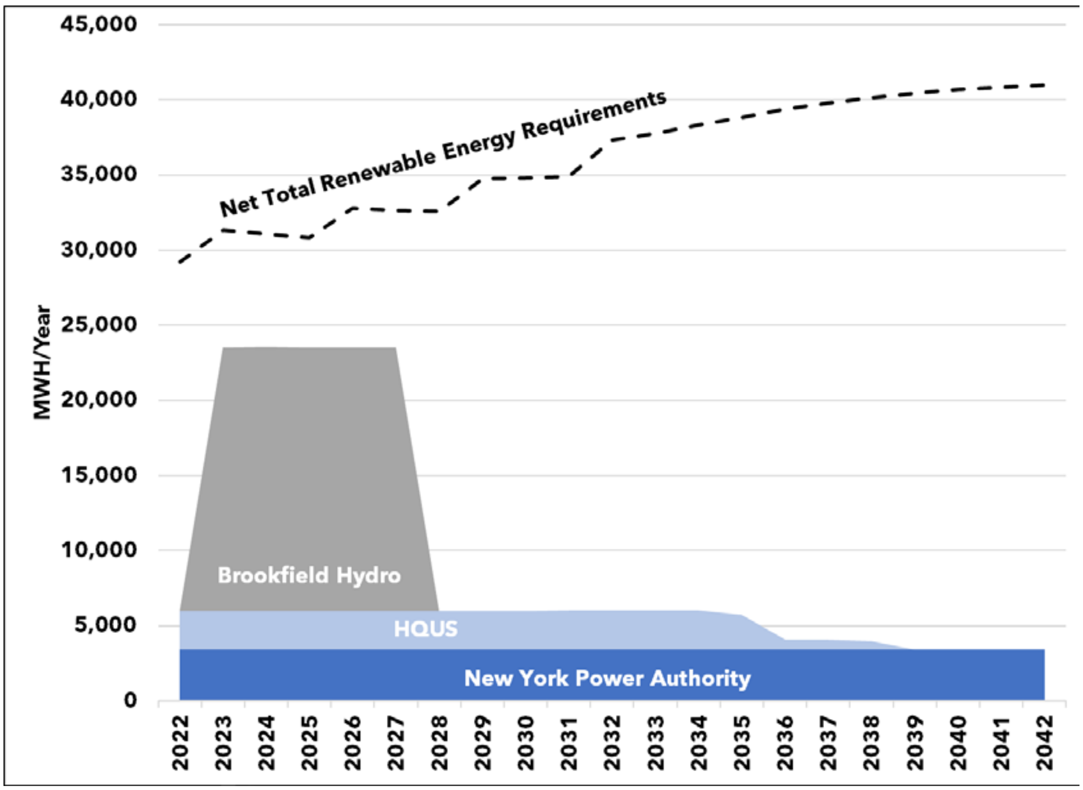
[8] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2023 and 2027, LED's Net Tier I requirement is about 31,000 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 24,000 MWH per year or 75% of LED's Net Tier I requirement. Through 2027, the remaining Net Tier I requirement (deficit) is about 7,000 MWH.

Figure 7: Tier I - Total Renewable Energy Supplies

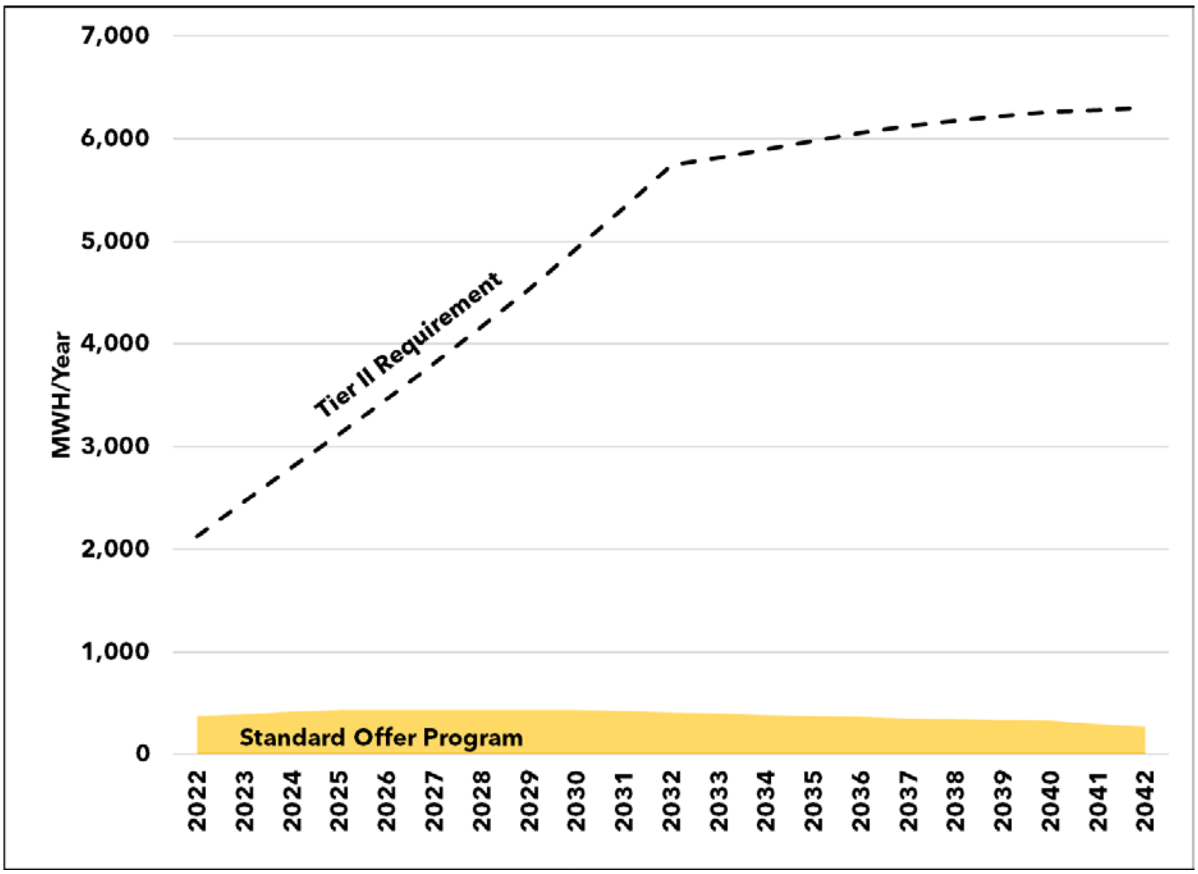


LED is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). These are presently the lowest cost source of Tier I-compliant RECs in the region, and their price has ranged from a low of $1.00 to a high of $10.00 per MWH over the past five years. 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 $89,000 per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 8 shows LED's Distributed Renewable Energy (Tier II) requirement, which rises steadily from 5,500 MWH in 2023 to 5,900 MWH in 2032. This requirement can be met with a 3.5 MW solar project, and LED is currently working with a developer to secure a site within its service territory to build a solar project of this size. As a result, we anticipate that LED's Tier II obligations will be met by this resource in the coming years. In the meantime, LED will most likely purchase Vermont Tier II RECs from other VPPSA members to fulfill its requirements.

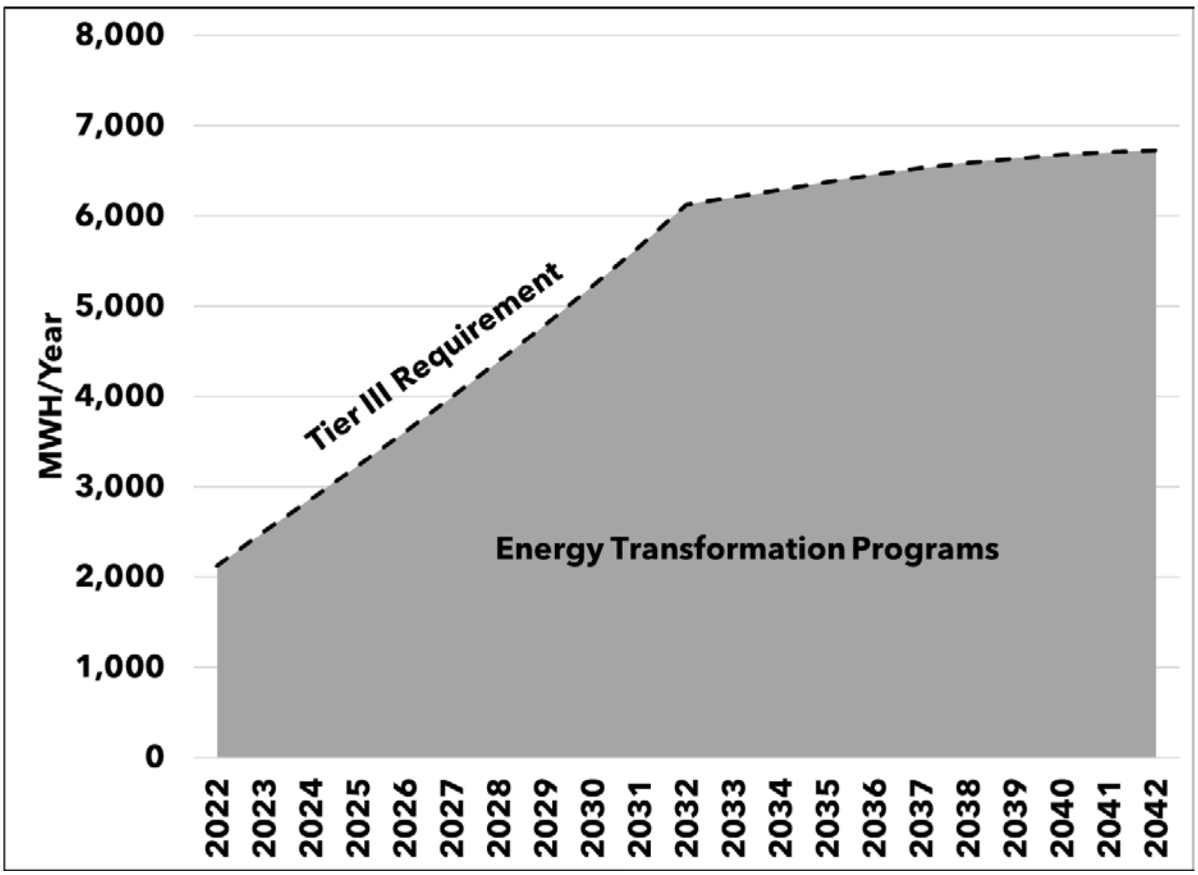
Figure 8: Tier II - Distributed Renewable Energy Supplies



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 9 shows LED's Energy Transformation (Tier III) requirements, which rise from about 2,000 MWH in 2022 to 6,000 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 9. 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 9: Energy Transformation Supplies



In the event that prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. As mentioned in the Demand chapter, LED is currently working with Okemo Mountain on a potential Tier III project that would switch Okemos snow making from diesel to electricity. Initial estimates indicate that a custom project of this size would easily fulfill LED's Tier III requirements.

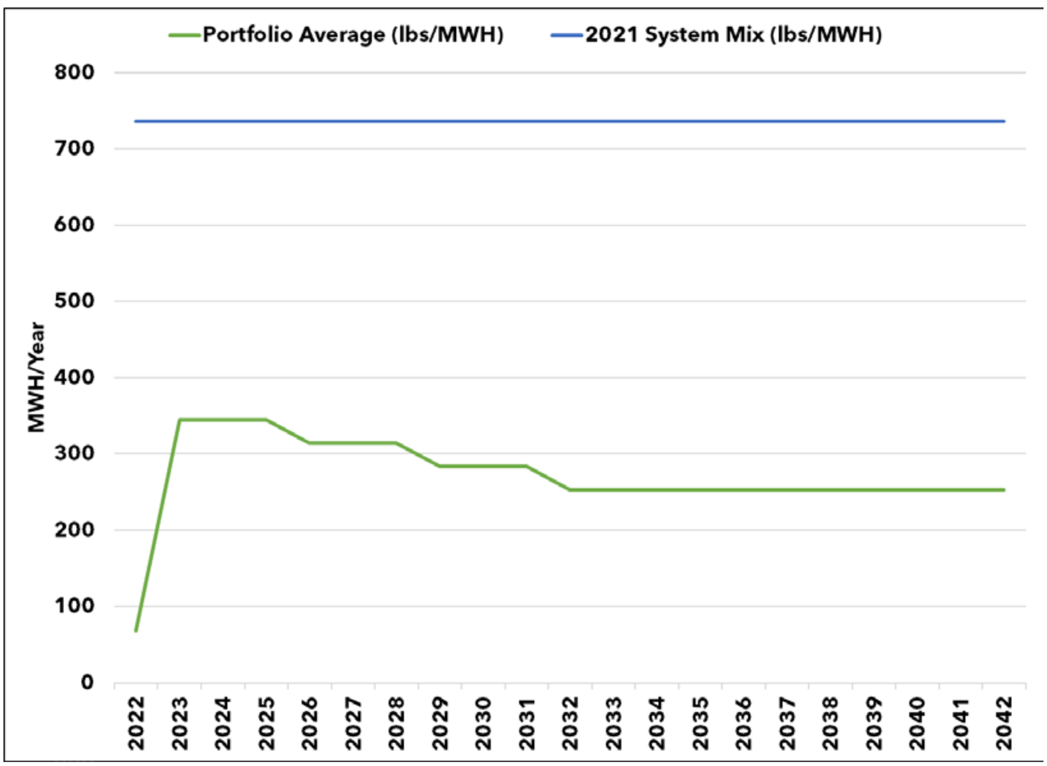
In any event, LED's will follow a three-part strategy to fulfill its Tier III requirements.

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

CARBON EMISSIONS AND COSTS

Figure 10 shows an estimate of LED's carbon emissions rate compared to the 2021 system average emissions rate in New England[10]. 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.[11]

Figure 10: Portfolio Average Carbon Emissions Rate (lbs/MWH)



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

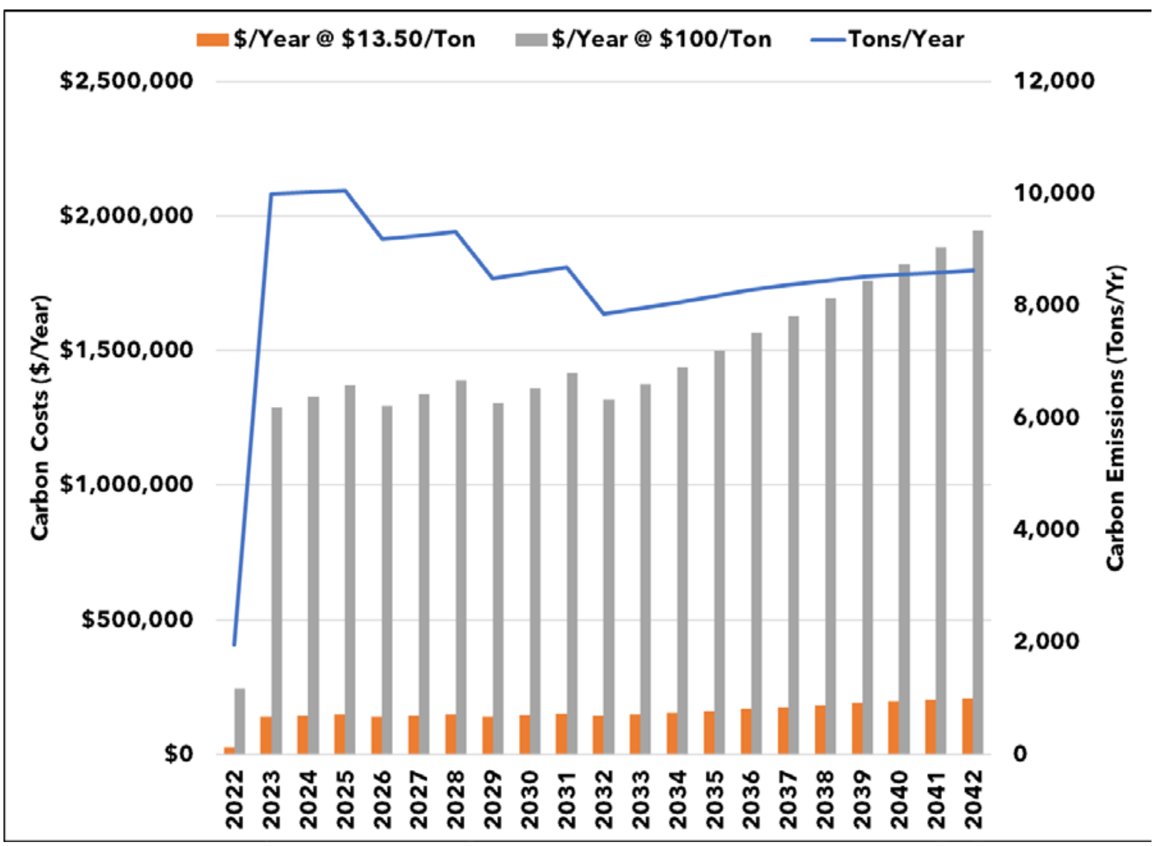
[11] For the current value of the NEPOOL Residual Mix, please visit https://www.nepoolgis.com/public-reports/.

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 2,000 tons/year in 2022 up to 10,000 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 $26,000/year and about $142,000/year in 2032. Using AESC prices, the range is $245,000/year in 2022 up to almost $1,300,000 per year in 2032.

Figure 11: 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 12 shows the year-by-year trajectory of these changes to the RES.

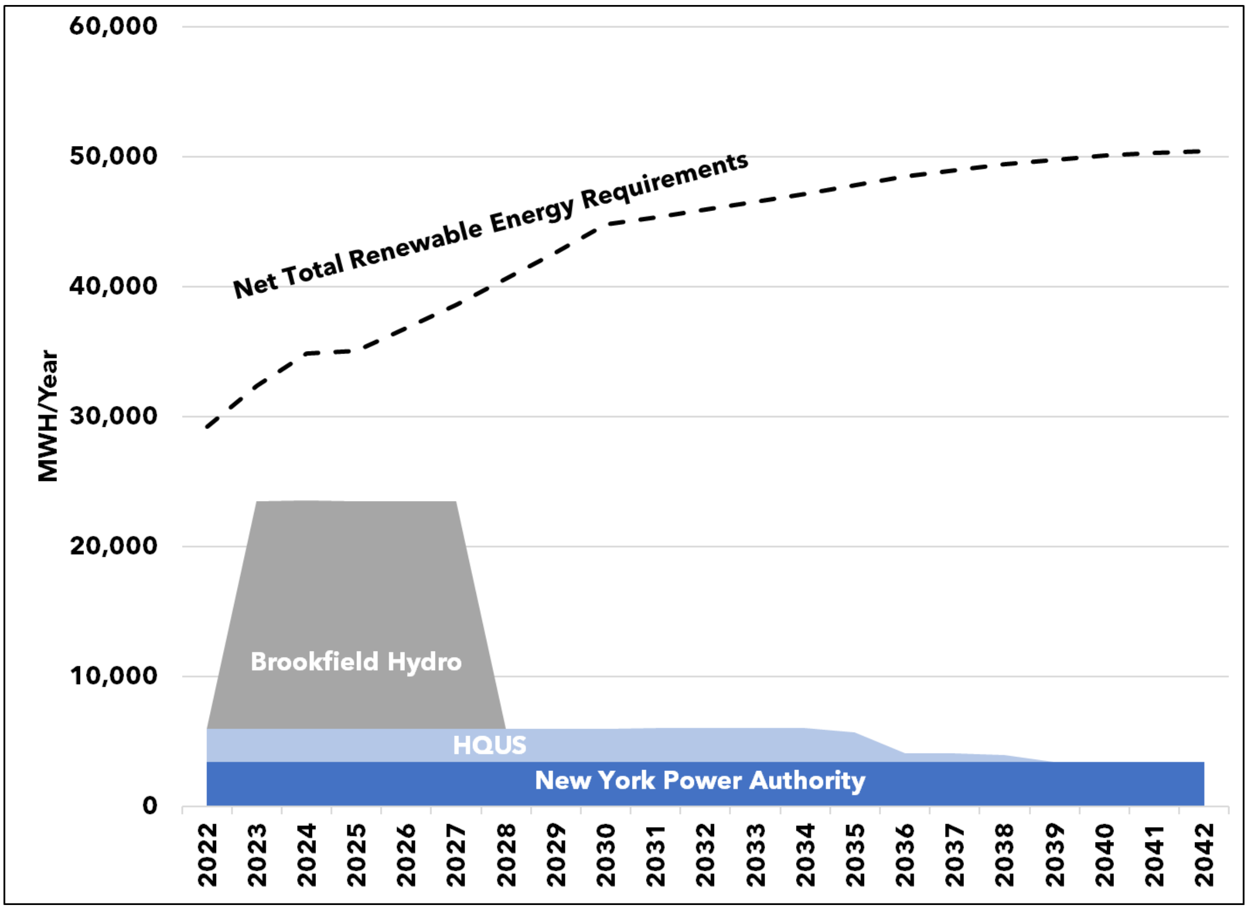
Figure 12: RES 2.0 Requirements

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: (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, LED 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. Tier II requirements would be 20% by 2030, and Tier I's requirement is net of Tier II. In any case, LED's requirement would rise from 30,000 MWH per year in the 2022 to 45,000 per year in 2030.

Figure 13: Tier I Requirements Under RES 2.0

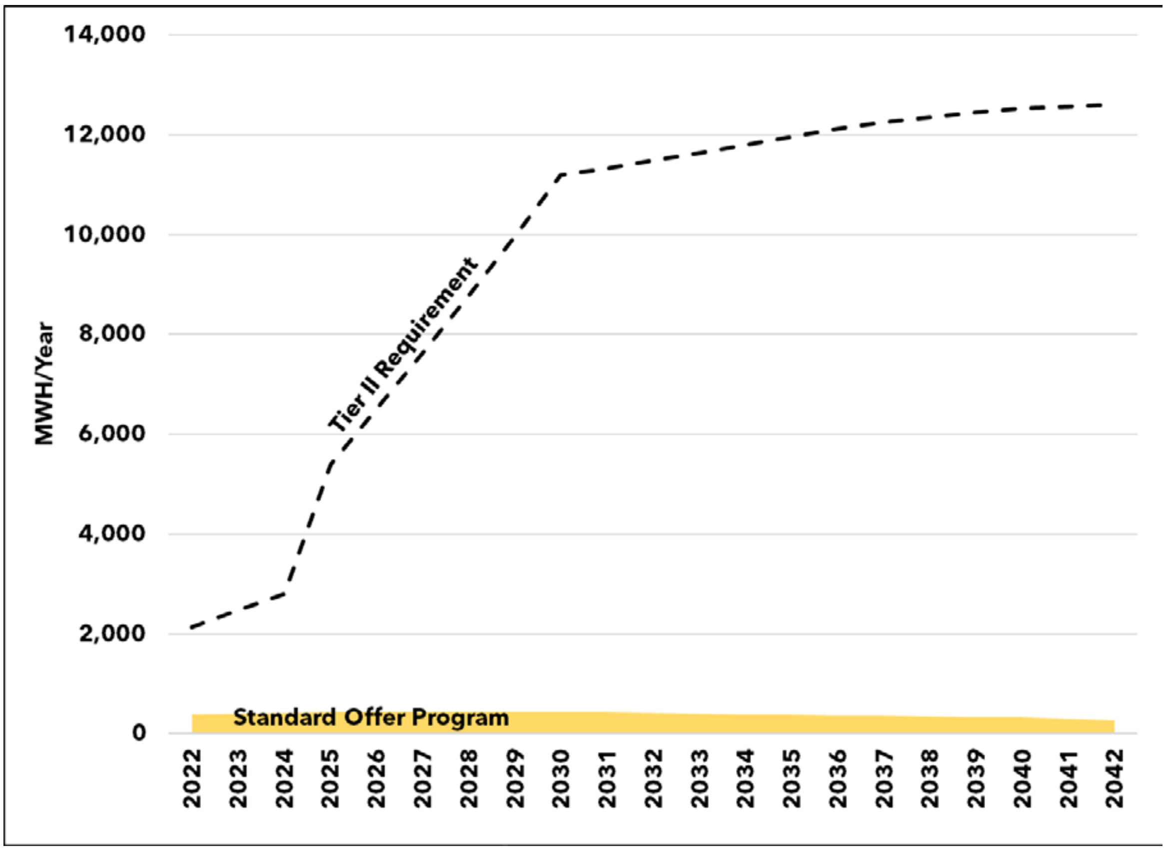


LED could meet this requirement by purchasing any number of hydro resources in New England, but it could also purchase a wind resource, whose Class I RECs could be resold and act as a hedge against the cost of Tier I RECs. The financial impact of this strategy will be measured in the Financial Analysis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

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The impact of a 20% by 2030 Tier II requirement is shown in Figure 14. In 2030, the requirement rises to about 11,000 MWH per year, and as a result, 7 MW of solar 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.

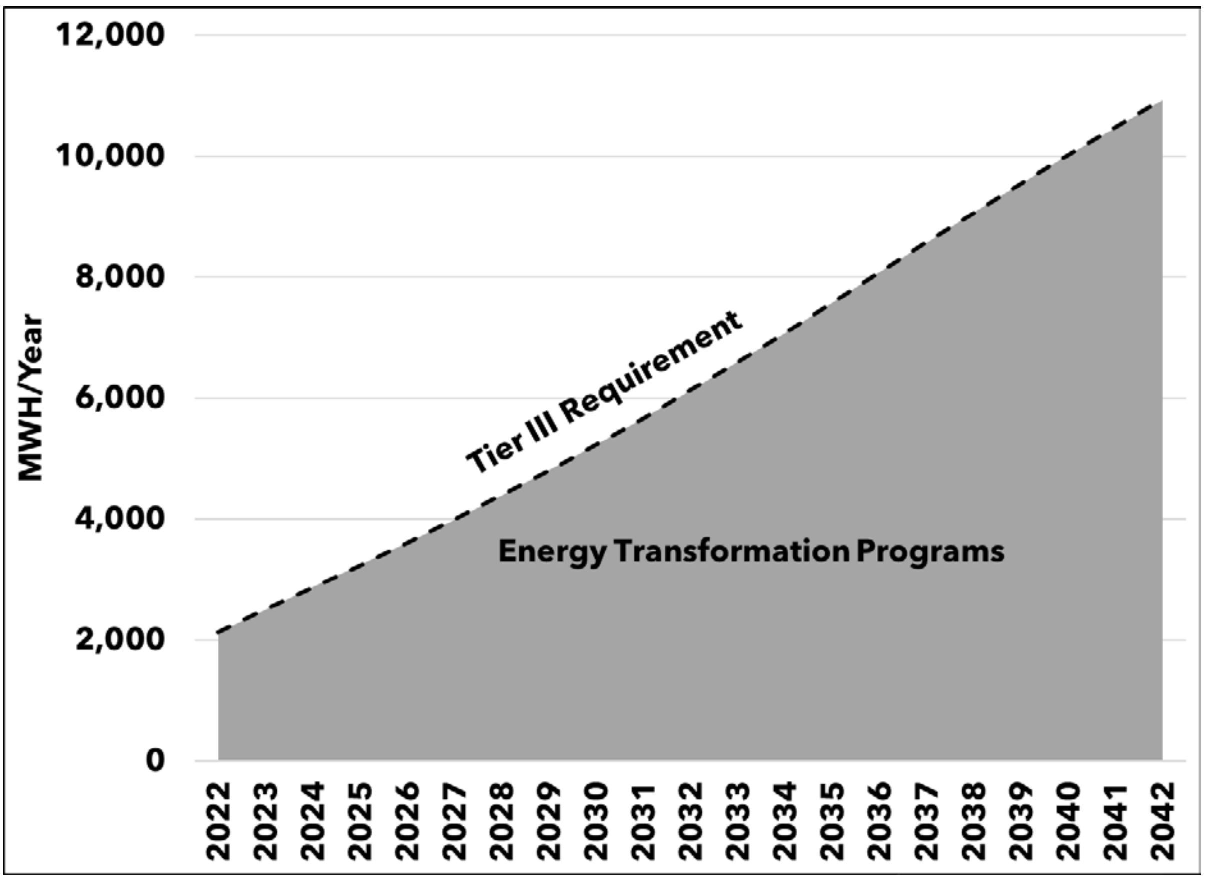
Figure 14: Tier II Requirements Under RES 2.0



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 15 shows LED's Energy Transformation (Tier III) requirements, which rise from about 2,000 MWH in 2022 to 11,000 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.

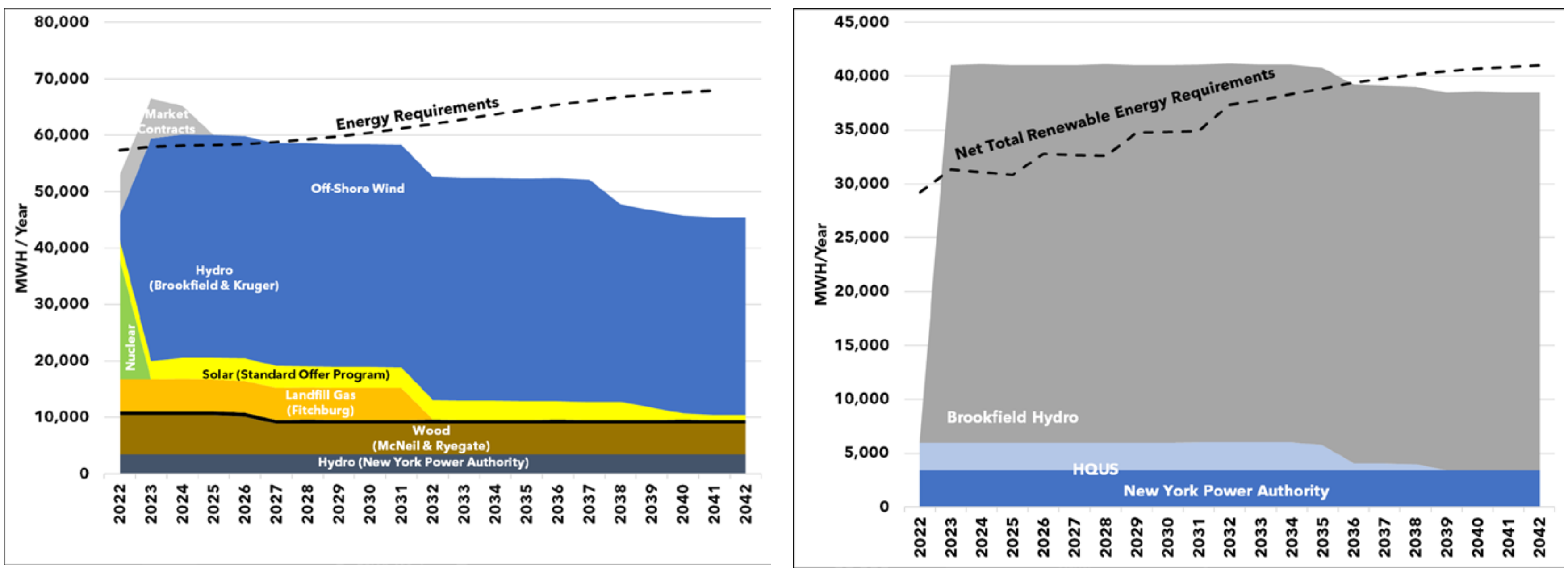
Figure 15: Tier III Requirements Under RES 2.0



PROCUREMENT PLAN FOR RES 1.0

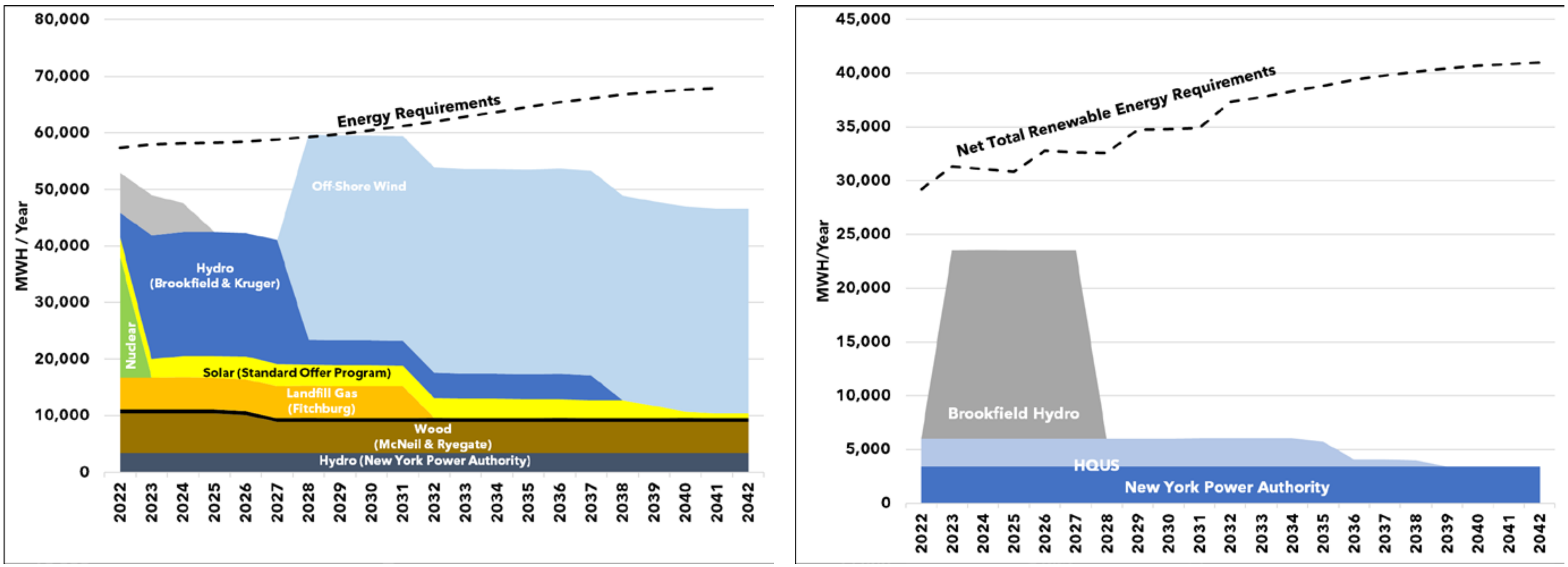
Under RES 1.0 requirements, LED has two primary options to procure the energy and Tier I RECs that it requires. First, it can purchase more hydro energy that is bundled with Tier I RECs. A doubling of the existing Brookfield contract, from 2.0 MW to 4.0 MW 7x24, would fulfill LED's energy requirements through 2030. However, it would create a 20-30% surplus of the Tier I RECs. In the context of VPPSA's overall Tier I obligation, this is a manageable level of REC market exposure, and a combination of internal sales to other VPPSA members and/or a multi-year REC contract can be used to manage the surplus.

Figure 16: RES 1.0 Option 1 – Hydro Energy & Tier I RECs Compared to Requirements



The other option to fulfill RES 1.0 is to purchase 9 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 17: RES 1.0 Option 2 – Off-Shore Wind Energy & Class I RECs Compared to Requirements



HEDGING TIER I WITH CLASS I RECS

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

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: 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 18 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 18: 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.

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 LED's energy requirements, and gives LED a short-term 16% surplus position on Tier I RECs. Second, the offshore wind resource is procured in 2028, but only 7 MW is required. This leaves room for the third resource, 7.0 MW of new solar, that would be required to meet a 20% by 2030 requirement under Tier II.

Figure 18: RES 2.0 Energy Resources Compared to Requirements

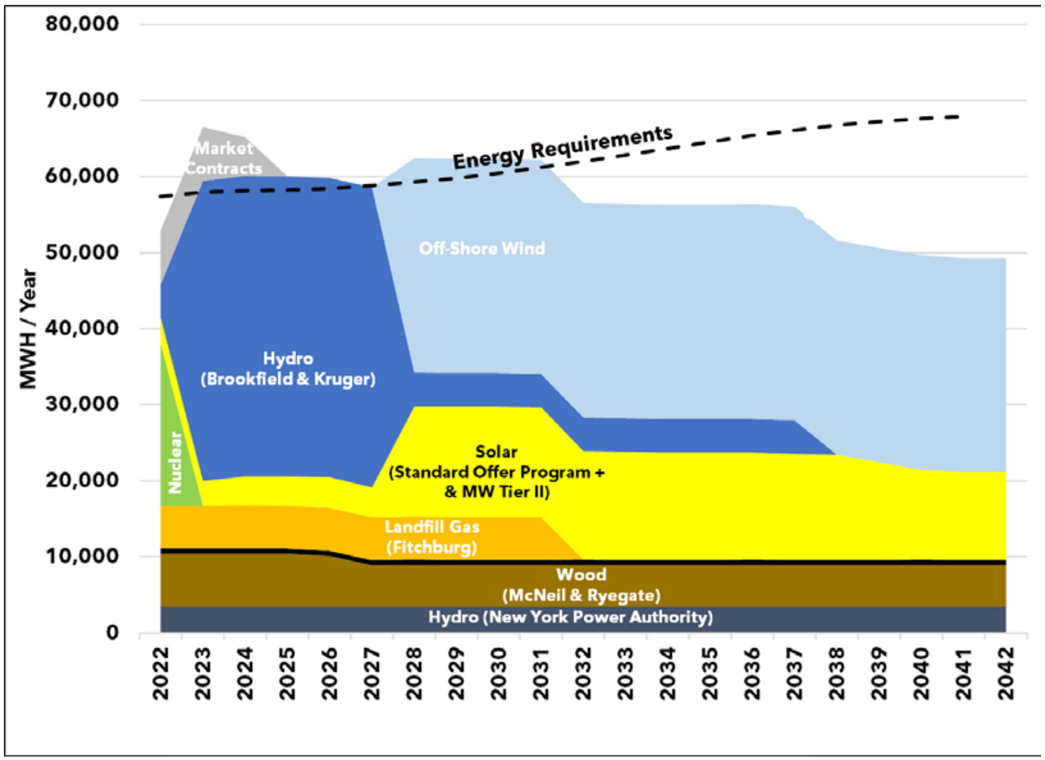
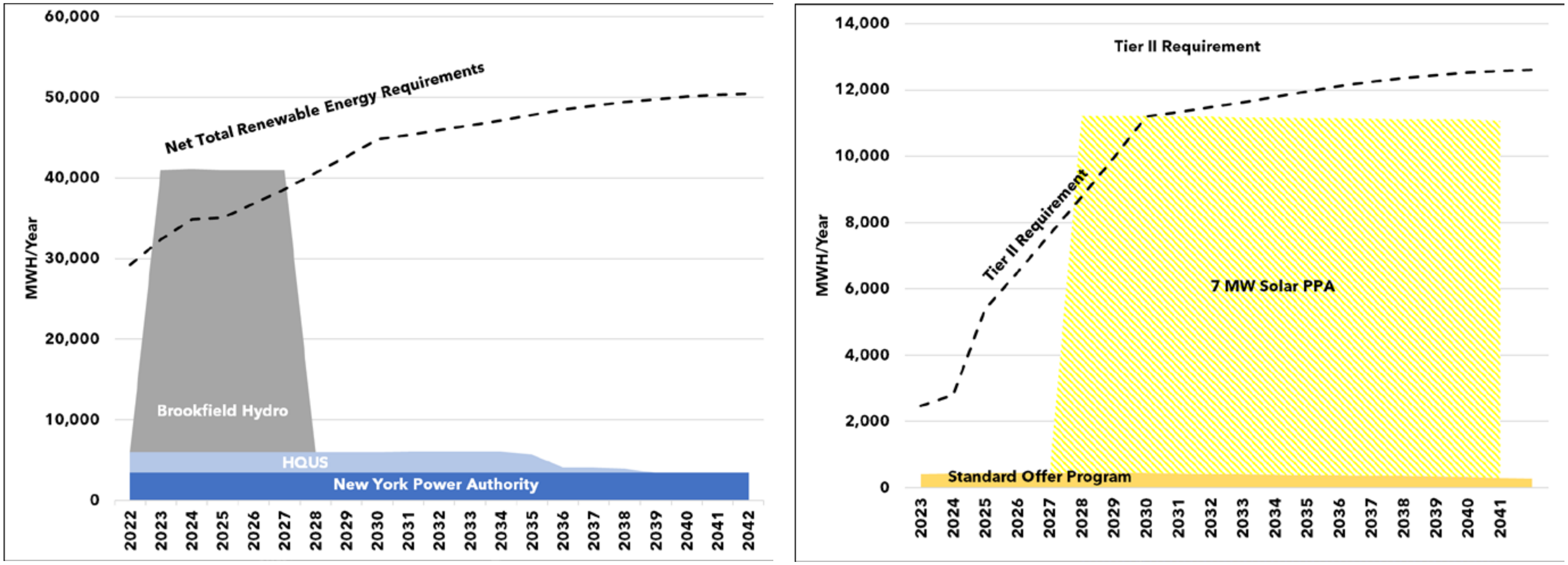


Figure 19: RES 2.0 Tier I and Tier II Resources Compared to Requirements



The timing and magnitude of the hydro, solar and offshore wind resource procurements can change, and economics and resource availability will ultimately determine when and how much of each 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, LED'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? LED's energy requirements are fulfilled before its Tier I requirements are fulfilled. As a result, a 100% Tier I requirement would force LED to either procure too much Tier I RECs or procure an unbundled Tier I REC contract. Both circumstances are commercially manageable. For example, surplus Tier I RECs can be resold and unbundled Tier I REC contracts can be purchased in the 1-3 year time frame. However, 5-20 year REC contracts are rare, and 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 LED's can reasonably develop and use. LED's service territory is limited in both area and in suitable terrain. Furthermore, LED already has sufficient volumes of existing daytime resources during the summer months, namely the Chester 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, LED already has enough daytime, Tier II resources. Procuring more would force LED 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

LED receives transmission service from GMP (previously owned by Central Vermont Public Service). LED owns approximately 1,800 feet of 46KV transmission line that connects from the GMP transmission to the Howard Barton Jr. Substation (previously named Rt. 103 Substation), Commonwealth Avenue Substation and the Smithville Substation. The Commonwealth Avenue transmission is #1 copper stranded conductor, Rt. 103 transmission is 4/0 ACSR conductor and the Smithville transmission is .477 mcm ACSR conductor. All three transmission lines have gang operated air brakes to isolate from the GMP transmission line. The GMP 46 KV transmission is a loop feed system, so LED's substations can be fed from Mt. Holly to the north or from Cavendish to the south.

LED has approximately 65 miles of distribution lines operating at 12.5 KV located in the Village of Ludlow, and the towns of Ludlow, Plymouth and Proctorsville.

LUDLOW SUBSTATIONS

LED owns and operates three substations. Each substation is briefly described below.

HOWARD BARTON JR. SUBSTATION

The Howard Barton Jr. Substation is located in the Town of Ludlow on Mega Watt Lane just north of the Village of Ludlow. It consists of a 14 MVA transformer with the high side voltage of 46 KV and the low side voltage of 12,470/7200 grounded wye. There are three 4/0 circuits feeding out of the substation with each one protected by an ABB vacuum type recloser. All 3 circuits can be tied together or tied to a different substation to conduct maintenance on the substation transformer or any other work to be conducted. All three reclosers have the ability to download information to see what the loads are on each phase and when any outages have occurred. The voltage regulators on the Jackson Gore circuit are electronic type that also provide information such as loads and power factor on all three phases.

LED is evaluating upgrading 6 out of 9 regulators to current technology over the next 2 to 3 years depending to some extent on load growth.

Figure 20 Ludlow's Howard Barton Jr. Substation

COMMONWEALTH AVENUE SUBSTATION

The Commonwealth Avenue substation is located in the Village of Ludlow on Commonwealth Avenue. It consists of a 15 MVA transformer with the high side voltage of 46 KV and the low side voltage of 12,470/7200 grounded wye. There are two 4/0 circuits feeding out of the substation with each one protected by a Cooper oil circuit type recloser. Both circuits can be tied together or tied to a different substation to conduct maintenance on the substation transformer or any other work to be conducted. Since the last IRP, LED has added switches to enable banking of regulators in order to feed either circuit, or both circuits, coming out of the substation. Both reclosers have the ability to download information to see what the loads are on each phase and when any outages or faults have occurred. The voltage regulators on both circuits are electronic type that also provide information such as loads and power factor on all 3 phases.

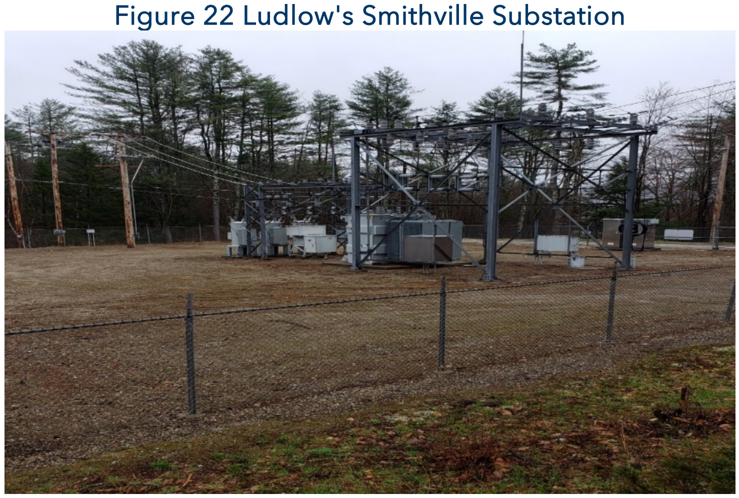
Figure 21 Ludlow's Commonwealth Substation

SMITHVILLE SUBSTATION

The Smithville Substation is located in the Town of Ludlow on DeRoo Lane just south of the village of Ludlow. It consists of a 14 MVA transformer with the high side voltage of 46 KV and the low side voltage of 12,470/7200 grounded wye. There is only one 4/0 circuit feeding out of the substation which is protected by a breaker. The one circuit can be tied to another feeder from the Commonwealth Substation to conduct maintenance on the substation transformer or any other work to be conducted.

LED recently upgraded regulators due to load growth. LED installed underground circuit to replace about a mile of overhead cross-country line from the substation to rt 103, improving reliability by minimizing storm damage and also improving aesthetics.

Figure 22 Ludlow's Smithville Substation



CIRCUIT DESCRIPTION:

Table 19 Ludlow Circuit Description

Circuit Name	Description	Length (Miles)	# Customers by Circuit	Outages by Circuit 2021
Lake Area	A 4/0 circuit protected by ABB vacuum type recloser, feeding out of the Howard Barton Jr. Substation.		676	4
Solitude	A 4/0 circuit protected by ABB vacuum type recloser, feeding out of the Howard Barton Jr. Substation.		150	0
Jackson Gore	A 4/0 circuit protected by ABB vacuum type recloser, feeding out of the Howard Barton Jr. Substation.		15	0
High St.	A 4/0 circuit protected by a Cooper oil circuit type recloser, feeding out of the Commonwealth Avenue Substation.		1,056	0
Main St.	A 4/0 circuit protected by a Cooper oil circuit type recloser, feeding out of the Commonwealth Avenue Substation.		1,312	1
Smithville	A 4/0 circuit protected by a breaker, and reclosers feeding out of the Smithville Substation.		598	1

For additional details about each circuit, please see the Ludlow Substations section (above). LED uses the Public Utility Commission Rule 4.900 Outage Report to evaluate the cause, number, and length of outages.

T&D SYSTEM EVALUATION

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

OUTAGE STATISTICS

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

Table 20: Outage Statistics

	Goals	2017	2018	2019	2020	2021
SAIFI[12]	**3.0**	1.2	2.3	0.1	1.1	0.0
CAIDI[13]	**0.9**	0.3	0.6	0.9	0.3	0.9

LED tracks all outage statistics as part of its Service Quality Reliability Plan (SQRP). As noted above, LED also uses the Public Utility Commission Rule 4.900 Outage Report to evaluate the cause, number, and length of outages in order to correct any problems and prevent any issues that may materialize in the future. These outage statistics allow LED to examine causes by circuit and develop plans for the most cost-effective reliability improvements. The baseline targets are met by a good maintenance program, tree clearing and the installation of fault locators on overhead feeders.

[12] System Average Interruption Frequency Index

[13] Customer Average Interruption Duration Index

Currently, LED has feeder back up capabilities on all main circuits. The circuits can be fed from either substation with some manual switching involved. Animal guards are installed on all new transformers and other equipment that can accommodate them. Guards are also installed on existing transformers and equipment during routine maintenance and as soon as possible after an outage occurs. LED uses fault locators on all primary underground lines and uses overhead fault locators on all feeds out of the substations and various places on the system. The fault locators help in determining the location and phase that had experienced a fault.

POWER FACTOR MEASUREMENT AND CORRECTION

During November of 2007 LED conducted a power factor study of its system which was performed by PLM Engineering. The study looked at capacitors currently used on line and where new ones need to be placed. Some of the units are fixed banks and others are switched banks. LED completed the installation of the new capacitors in August 2011 which have helped LED achieve a power factor of just over 99%.

DISTRIBUTION CIRCUIT CONFIGURATION

In 1999, LED converted its entire system voltage to 12,470/7,200 grounded wye. LED installs low loss distribution transformers that are evaluated and uses tree wire on primary overhead lines. LED addresses circuit configuration, phase balancing and fuse coordination on a continuous basis as the system changes. All main feeders have backups with other feeders with circuits from the same substation or from other substations. All circuits feeding from the substation are protected by electronic reclosers. Information is obtained on phase loading. During peak loads amperage recorders are installed in various locations to identify peak loads and average loads per phase, which also helps on fuse sizing for engineering. Phases that are unbalanced are addressed by identifying locations and scheduling an outage to move transformer taps or line taps to the appropriate phase for engineering.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

LED has system protection practices that cover transmission, substation and distribution operation. Each protection methodology is discussed briefly below.

TRANSMISSION SYSTEM PROTECTION

The transmission system is protected by GMP and VELCO.

SUBSTATION PROTECTION

The substation equipment is protected by high side fuses.

DISTRIBUTION PROTECTION

The distribution system protection involves circuit reclosers and fuses. All side taps off the main line distribution feed are fused.

SMART GRID INITIATIVES

EXISTING SMART GRID

On the transmission side, LED worked with GMP to install SCADA-controlled switches for the transmission that feeds from the Cold River Tap to the Howard Barton Jr. Substation from the north of Ludlow and from the south at the Smithville Substation tap which feeds from Ascutney. Fiber has been installed at all three of Ludlow's substations. LED has installed reclosers on its system that provide it with important data on loads, faults and other important information.

PLANNED AMI

Beginning in 2018, LED 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 LED. 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 21: 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. LED 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 LED does not provide water service, no benefit from inclusion of water meters has been added to the evaluation of an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 22: AMI Readiness Evaluation (2019)

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

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.

LED 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 (N/A)
- 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 1.84 and a 4.8-year payback, providing LED 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, LED is optimistic that it will begin implementation of a new AMI system within the next two to three years.

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

LED 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

RECONDUCTORING FOR LOSS REDUCTION

When rebuilding an area, LED re-conductors lines with lower loss conductors. The majority of LED's lines already have low loss conductors. The average distribution line losses are around 4.1%

TRANSFORMER ACQUISITION

LED evaluates the life-cycle cost when replacing transformers. LED bids out to a minimum of three to four manufacturers for low loss transformers (amorphous core) and evaluates them over the 20-year time period. LED does not purchase rebuilt transformers.

CONSERVATION VOLTAGE REGULATION

LED's voltage setting is done with voltage regulators in substations only; voltage is set between 120 and 121.5 volts to provide proper voltage to the first and last customers. LED does not have voltage regulators outside the substations due to the short distance to last customers.

LED participates in the ISO-New England voltage reduction tests twice a year, in the Spring and Fall. LED monitors customer voltage on last customers of a circuit being fed from each substation to make sure proper voltage is supplied. LED does this by installing a voltage recorder at the meter and downloading the information to review.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

As previously mentioned, LED evaluates the life-cycle cost when replacing transformers. LED bids out to a minimum of three to four manufacturers for low loss transformers (amorphous core) and evaluates them over the 20-year time period. LED does not purchase rebuilt transformers. LED does not currently have an official DTLM program. Every transformer that is worked on is thoroughly checked.

SUBSTATIONS WITHIN THE 100 AND 500 YEAR FLOOD PLAINS

None of LED's substations fall within the 500 year flood plain.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

All of LED's primary underground facilities are owned by LED while all of its secondary underground facilities are customer-owned. The company standard for minimum depth required for the laying of facilities is 36 inches. The facilities are located by sensor. The facilities documented with drawings are sufficient to find and mark their location upon a notice of planned excavation in the area. LED 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

LED purchases standard certified transmission and distribution equipment from established trusted vendors. The majority of LED's equipment is purchased from Westco and Irby. LED prioritizes quality equipment over low purchase prices.

MAINTAINING OPTIMAL T&D EFFICIENCY

System maintenance includes a number of components. Each is discussed below.

SUBSTATION MAINTENANCE:

LED inspects each of the substations monthly. Transformer oil test are done annually. Reclosers and regulators are tested every two years by TSI and UPG. The internal battery at the reclosers has an internal test that is done once per month. Any failure will be displayed and picked up during monthly inspections. In addition to the visual inspections an infrared inspection is done every year in December when we are experiencing our heaviest load. Any problems are addressed as soon as possible. The following form (below) is used when performing substation inspections.

Figure 23 Ludlow Substation Inspection Form

Substation:____________________________________**Month/Year:**______________________________

Description	**OK**	**Needs Attention**		**Description**	**OK**	**Needs Attention**
Transformer				**Air Breaks & Disconnects**		
Oil Levels Correct						
Gauges in Good Condition						
Any Oil Leaks						
Bushings HV / LV						
Fans Tested				**Other Equipment**		
Pressure Gage + or -				Fence		
Heaters				Gate		
Reclosers				Signs		
Bushings				Ground Straps on fence, etc.		
Battery				Trees		
Disconnects				Hard Hat		
				First Aid Kit		
Regulators				Phone		
Bushings				Switch Sticks		
Any Oil Leaks				Tags		
Oil Level Correct				Rubber Gloves		
Switches & By Passes				Lock		
Control Power On						
Test Reg. 3 to 5 Steps						
Set Into Auto Position						
Reset Drag Hand						
Test Output Voltage						

Checked By:____________________________________Date and Time:______________________________

Comments:____

POLE INSPECTION:

Currently, LED has an internal pole inspection process in place. LED's system is very condensed, so it is able to inspect the system on a regular basis for problems with poles, crossarms, etc. This also ties in with the capital plan of rebuilding lines before problems arise. LED has never had a pole fail on its own. LED has a complete GPS with inventory of all poles which it can obtain the date of the pole as long as the date was legible at the time of gathering the information. LED replaces poles as needed, on an ongoing basis. In recent years, LED replaced as many as 200 poles. LED replaces numerous poles per year, and it considers its pole inventory to be in good shape. Many poles are changed for make-ready work. Also, LED visually inspects poles during the regular line of work and is able to make observations of all poles over the course of two years. Given the compact nature of its system, the ability to inspect all poles within a two year cycle, and the additional cost associated with retaining outside contractors, LED plans to continue with the internal pole inspection program. LED is exploring the use of its evolving GIS system to assist in tracking pole inspections. Ludlow has a spreadsheet system for tracking pole inspections and anticipates receiving shape files from the GIS system currently under development. As the GIS system matures over the next couple years the intent is to build pole management and tracking capabilities directly into the GIS system.

EQUIPMENT MAINTENANCE:

LED has replaced all of its porcelain disconnects on its system. A program was developed to replace them back in 2006 and was completed in 2008. Any insulators and connectors that need to be replaced, are replaced any time work is being done on a pole.

ENERGY LOSSES AND SYSTEM EFFICIENCY:

LED has a standard conductor size of 1/0 and 4/0 AAA conductor for overhead lines which provides lower inventory cost. The standard conductor size for primary underground is 1/0, 4/0 and 500 mcm aluminum 220 mill which also helps in lower inventory cost. To provide system efficiency for underground, LED has been installing loop feeds into all developments with underground feeds and has loop feeds on all major underground feeders. LED has 13.74 miles of primary underground lines. To provide system wide efficiency all substations are phased with each other and with manual switching any substation can pick up the load of another substation whether it is scheduled maintenance or an unplanned outage.

LED monitors system energy losses by tracking metered system load at its interconnections to GMP and comparing it to metered energy sales to our customers. Also, LED takes into account for street lighting using standard lighting cycles and average consumption data on the different lighting fixtures used within the system. This calculation is done annually. LED tries to meter as much as possible, as it is important to LED to maintain an accurate measure of load. Even the SCADA system is metered. LED's total distribution line losses in 2021 were 4.1%.

LED replaced all of the Village streetlights with LED lights in 2021 and is working to replace them in neighboring towns. The efficiency effort saved approximately $67,000 and 100,000 kWh in 2021.

In efforts to reduce losses, LED has converted its entire system voltage to 12,470/7200 grounded wye. This was completed in 1999. LED installs amorphous core distribution transformers and uses tree wire on primary overhead lines.

TRACKING TRANSFER OF UTILITIES AND DUAL POLE REMOVAL (NJUNS)

LED does not currently use NJUNS, but it does send pole information to TDS and Comcast, and they respond very well for pole transfers. LED does not currently have any dual poles on its system, so this system is working sufficiently.

RELOCATING CROSS-COUNTRY LINES TO ROAD-SIDE

LED relocates cross-country lines to road-side when such relocation can be done consistent with cost consideration and customer concerns in terms of rights-of-way. Some customers do not want to see the lines in front of their houses. This has not been overly problematic so far. There have been a few issues with easements. If it is determined to be problematic to relocate a cross-country line to road-side, LED rebuilds the line where it is currently located.

DISTRIBUTED GENERATION IMPACT:

Currently, distributed generation is not having a great impact on LED. LED has only 11 solar customers with a combined total installed capacity of 232 kW and very little new solar net metering is in the "pipeline."

INTERCONNECTION OF DISTRIBUTED GENERATION

LED recognizes the unique challenges brought on by increasing penetration levels of distributed generation. LED 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 LED 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, LED will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow LED 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). 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 LED's service territory, LED 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 born by the ratepayers of LED. As a reasonable compromise, LED 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, LED 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. LED recognizes the need to standardize efforts aimed at certifying inverter compliance with the ISO SRD and will work with VPPSA and PSD to achieve use of common forms and process in this regard.

DISTRIBUTION-LEVEL IMPACT OF ELECTRIFICATION

LED 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. LED 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, the addition of generation/storage at key locations, or a combination of several of these.

At the present time LED 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. LED believes that the planned implementation of AMI will play a key role in providing appropriate tracking and analytics, enabling LED to develop timely distribution system management responses to locational trends and developing load concentrations.

The LED distribution system currently has sufficient capacity for the immediate foreseeable future. As Table 23 indicates, LED has one large solar project and a handful of smaller net metering units scattered across its system. LED is aware of other scattered electrification measures in place, but information on this front is incomplete. Maximum loading on any of LED's substation transformers ranges between 42% and 48% of it's nameplate capacity and ranges between 11% and 20% on average.

Table 23: LED Distribution-Level Impacts 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
Howard Barton Jr.	1	14 MVA	42.2%	11.0%	Lake	12.47	3	165			
					Solitude	12.47				Okemo	Okemo
					Jackson Gore	12.47				Okemo	Okemo
Commonwealth	1	15 MVA	47.50%	15.80%	High Street	12.47	5	42.75		Okemo	Okemo
					Main Street	12.47				Okemo	Okemo
Smithville	1	14 MVA	43.9%	20.20%	Smithville	12.47	3	26.45		Magris	Magris
(1) Annual kWh / (transformer capacity * 8760)											
Prescriptive (HP,HPWH,etc) TIER 3 has limited availability											

Based on available information, LED's distribution system is adequate for the near future. Electrification impacts have yet to become a significant issue. LED is currently working proactively with Okemo Mountain Resort to explore the most efficient way to support significant electrification initiatives anticipated by the resort. As the anticipated AMI and GIS implementations reach maturity LED 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

LED has a 7-year average tree clearing and trimming cycle on its distribution lines. The sub-transmission lines are mowed with a tractor every 2 years to keep the brush from growing so the only tree work necessary is side trimming trees on the edge of the right-of-way. This is why the sub-transmission lines can go for an average of 10 years before needing to be trimmed. Tree trimming is tracked in a database and inspection of the lines dictates if an area might need attention before its regular schedule.

Depending on the weather pattern and the type of trees some areas will last longer than others and trimming might not have to be done as often as others. Some areas might not have to be trimmed for several years while others might have a few sections of line that need to be trimmed sooner than the scheduled time. All lines are trimmed to the edge of the right-of-way. The tree trimming width is 15 feet on either side of the line for three-phase line and 10 feet on either side of the line for single-phase lines.

LED uses contract tree crews and also uses in-house crews to do the work. LED routinely reviews the tree trimming program, utilizing inspections and feedback from its outage reports, to assure that the program maintains the vegetation and brush within its right-of-way appropriately and to make modifications to the management program in the event that the program is not maintaining adequate clearances of brush from the lines. In addition to its vegetation and brush management program, LED has a program to identify danger trees. Danger trees are identified by all of our utility personnel while patrolling the lines or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within LED's right-of-way. For danger trees outside of the right-of-way, LED contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, LED will periodically follow up with the property owner to attempt to obtain permission. Again, the success of this program is measured by whether danger trees are a root cause of system outages.

LED serves 65 miles of T&D line and has approximately 45 miles of line that requires vegetation management. It has budgeted $40,000 per year for the last 10 years and will budget the same for the next 3 years. The number of miles trimmed varies due to the trimming of three-phase lines vs. single-phase lines, which are not as time consuming due to the size of the right-of-way, or if the line is off road less area is trimmed in a year. Also, some of the lines require more tree removals than others which contribute to fewer miles trimmed in a year.

The majority of tree species in our service territory are pine, oak and maple. Most of our tree-related outages are due to severe storms with trees outside of the right-of-way coming in contact with the power lines. LED does not use herbicides on its system.

The emerald ash borer has not yet become an active issue in LED's territory. LED 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 LED's territory, affected trees will be cut down, chipped and properly disposed of.

Table 24 Ludlow Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Transmission	0.5 Miles	0.5 Miles	10 Years
Distribution	65	45	7

Table 25 Ludlow Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
Amount Spent	$30,330	$33,183	$18,740	x	x	x
Miles Trimmed	6	7	4.5	6.5	6.5	6.5

Table 26 Ludlow Tree Related Outages

	2017	2018	2019	2020	2021
Tree Related Outages	3	12	5	5	2
Total Outages	16	28	15	24	6
Tree-related outages as % of total	19%	43%	33%	21%	33%

The 2018 tree related outages, shown in the above table, were all due to high wind events which brought down large trees that were all located outside of the right-of-way.

STORM/EMERGENCY PROCEDURES

Like other Vermont municipal electric utilities, LED is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows LED to coordinate not only with public power systems in Vermont, but with those throughout New England. Representatives of LED are also on the state emergency preparedness conference calls, which facilitates in-state coordination between utilities, state regulators and other interested parties. LED uses the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. LED believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages.

PREVIOUS AND PLANNED T&D STUDIES

FUSE COORDINATION STUDY

A coordination study was completed by PLM in 2009 for all substation feeder reclosers and line reclosers. Since that time PLM has provided engineering support for LED including short circuit analysis and recommended protective device settings for all circuit reclosers on the LED system. A coordination review of the affected equipment has been performed each time a major equipment component has been added or replaced or a large customer load added. In each case, specific device settings recommendations have been provided by PLM and implemented by LED. In 2019 LED commissioned a full T&D system planning study (See Appendix G - Ludlow 2019 T&D System Study) which was performed by PLM, including a full review of existing overcurrent protection and branch fusing which indicated fusing on the system is appropriate. In the event of an outage, LED has the capability to manually switch 100% of its customers to a backup feeder.

SYSTEM PLANNING AND EFFICIENCY STUDY

In 2019 LED commissioned PLM to perform a comprehensive system planning and efficiency study. This study included a system-wide review with any recommended upgrades or changes documented in the study report.

The Ludlow 2019 T&D System Study (Appendix G) states:

> *"A review of the existing LED system (including visual observations and discussions with LED personnel) indicates that the system is generally in good physical condition,*
>
> *operating efficiently, and able to provide reliable power to all customers in the service*
>
> *territory now and throughout the study period. All customers are supplied via the regulated 12.47 kV distribution system. All substation equipment and line conductors are operating within their thermal limits."*

- Recommended Near Term Improvements
  - Implement updated substation voltage regulator settings (reflecting present system configuration and anticipated load levels)
  - Install additional power factor correction capacitors on the Smithville and Lake feeders
  - Perform phase load balancing on the Lake feeder
  - Replace the feeder circuit breaker at the Smithville substation with a circuit recloser (due to having reached the end of its expected service life).

- Longer Term Considerations
  - While there are presently no operating issues, the LED will need to budget and plan for the replacement of the substation transformer and six voltage regulators at the Howard Barton Jr. Substation. This equipment will likely reach the end of its expected service life during the 20-year study period.

- LED Planned Distribution Line Relocation Project
  - LED will be rebuilding and relocating approximately 1.2 miles of three-phase 12.47 kV distribution line on the branch of Smithville feeder that feeds the village of Proctorsville and vicinity. The planned event is needed to address aging facilities, riverbank erosion, and to provide improved access for service restoration.

- Additional Load at Okemo Mountain Resort
  - Okemo Mountain Resort (Okemo) has indicated to the LED that they
  - plan to install two new chair lifts. The affected feeders and substations have thermal capacity available to interconnect these new loads.
  - Okemo is also considering replacing its diesel-powered air compressors that are used for snowmaking with electric compressors. Preliminary discussions indicate that the incremental load could be in the 3 MW range, potentially necessitating a system impact study to focus on the interconnection requirements. LED is currently exploring options that do not require new line or substation construction and may include solar and/or storage as part of the solution.

CAPITAL SPENDING

CONSTRUCTION COST (2019-2021)

Figure 24 Ludlow Historic Construction Cost

Ludlow Electric Department		**Historic Construction**		
Historic Construction		**2019**	**2020**	**2021**
Misc Plant	Trans	6,161		
Misc Plant	Dist	15,709		
Misc Plant & general	General	79,082		
Misc Plant	Dist		48,164	
Misc Plant & General	Dist		301,902	
Station Equipment	Dist			3,614
Misc Plant & General	General			137,169
Total Construction		$ 100,952	$ 350,066	$ 140,783
Functional Summary:				
Production		$ -	$ -	$ -
General		$ 79,082		$ 137,169
Distribution		$ 21,870	$ 350,066	$ 3,614
Transmission		$ -	$ -	$ -
Total Construction		100,952	350,066	140,783

PROJECTED CONSTRUCTION COSTS (2023-2025)

Figure 25 Ludlow Projected Construction Cost

Ludlow Electric Department		**Projected Construction**		
Projected Construction		2023	2024	2025
Pickup Truck	General	40,000		
Misc Plant	Dist	96,625		
Misc Plant - General	General	31,875		
New Line -Magris	Dist	642,370		
Misc Plant	Dist		32,512	
Misc Plant - General	General		97,538	
Misc Plant	Dist			199,488
Misc Plant - General	General			33,163
General - Bucket Truck	General			350,000
Total Construction		$ 810,870	$ 130,050	$ 582,651
Functional Summary:				
Production		-	-	-
General		71,875	97,538	383,163
Distribution		738,995	32,512	199,488
Transmission		-	-	-
Total Construction		810,870	130,050	582,651

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	4 MW	2023-2042	$66/MWH Levelized
1.1	RES 1.0 - Tier I with Offshore Wind	9 MW	2028-2042	$95/MWH Levelized
1.2	RES 1.0 – Tier II with Solar	3.5 MW	2028-2042	$90/MWH Levelized
2	RES 2.0 Requirements	N/A	2023-2042	Monthly DALMP
2.1	RES 2.0 - Tier I with Hydro	4 MW	2023-2042	$66/MWH Levelized
2.2	RES 2.0 - Tier I with Offshore Wind	7 MW	2028-2042	$95/MWH Levelized
2.3	RES 2.0 - Tier II Solar PPA	7 MW AC	2028-2042	$90/MWH Levelized
2.4	RES 2.0 - Hydro + Wind + Solar		2023-2042	
3	Storage	4 MW, 12 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 0.8% 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	$3.9	$4.6	$5.3	$6.2	$6.8	2.2%
Transmission Charges	$1.8	$2.3	$3.1	$4.3	$6.1	6.1%
Administrative and Other Charges & Credits	$0.1	$0.2	$0.2	$0.2	$0.2	2.1%
Total Charges	$5.8	$7.1	$8.6	$10.8	$13.1	**3.7%**
Total Load - Including Losses (MWH)	57,429	58,801	62,021	66,136	68,121	0.8%
Coverage Ratio	97%	74%	33%	27%	15%	

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 4 MW and 12 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 1.0 and 2.0 scenarios. Notice that the PVRR increases by about $3.8 million dollars or 2.5% 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

#	Procurement Scenario	NPV	Unit	% Change
0	Reference Case	$152.9	PVRR (Million $)	
1	RES 1.0 - Tier I with Hydro	($2.8)	Chg. from Ref. Case	-1.8%
1.1	RES 1.0 - Tier I with Offshore Wind	($4.3)	Chg. from Ref. Case	-2.8%
1.2	RES 1.0 - Tier II with Solar	($0.1)	Chg. from Ref. Case	-0.1%
2	RES 2.0 Requirements	$156.7	PVRR (Million $)	2.5%
2.1	RES 2.0 - Tier I with Hydro	$0.9	Chg. from RES 2.0 Req.	0.6%
2.2	RES 2.0 - Tier I with Offshore Wind	($3.3)	Chg. from RES 2.0 Req.	-2.2%
2.3	RES 2.0 - Tier II Solar PPA	($2.7)	Chg. from RES 2.0 Req.	-1.8%
2.4	RES 2.0 - Hydro + Wind + Solar	($0.3)	Chg. from RES 2.0 Req.	-0.2%
3	Storage	($3.1)	Chg. from Ref. Case	2.4%

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 7 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.

1. They are size appropriate for the loads at LED's substations.
2. They are small enough to operate behind-the-meter with respect to ISO markets.
3. 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 LED were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, the cost to LED would be between $720,000 and $1,200,000 per year.

Figure 26: Annual Cost of a 4 MW AC Battery ($/Year)

($/kW-mo)	4 MW AC
$15.00	$720,000
$20.00	$960,000
$25.00	$1,200,000

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 $3.1 million.

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 2.5% 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. LED expects to continue developing potential sites within its territory, and may begin interconnection studies and permitting later this year.

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 2023–2024-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 a 4-7 MW solar project(s).
  - 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 proposed 4 MW/12 MWH storage proposal.
    - 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 – LED Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – LED – 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 – Ludlow IRP22 Demand Report.pdf

APPENDIX G: LUDLOW 2019 T&D SYSTEM STUDY

This appendix is provided separately in a file named:

Appendix G – Ludlow 2019 T&D System Study.pdf

APPENDIX H: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

Appendix H– Ludlow Tier III Life-Cycle Cost Analysis.pdf

APPENDIX I: SWCRPC REGIONAL ENERGY PLAN (MARC REGIONAL ENERGY PLAN)

Appendix I - https://publicservice.vermont.gov/content/southern-windsor-county-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
LED	Ludlow Electric Department
LIDAR	Light Detection and Ranging
LIHI	Low Impact Hydro Institute
LMP	Locational Marginal Price
LRTP	Long Range Transmission Plan
MAPE	Mean Absolute Percent Error
MARC	Mount Ascutney Regional Commission (formerly know as SWCRPC)
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
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
RGGI	Regional Greenhouse Initiative Auction
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
SWCRPC	Southern Windsor County Regional Planning Commission (recently replaced by MARC)
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

Vermont Public Power Supply Authority

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Vermont Public Power Supply Authority
2022 Tier 3 Annual Plan

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing this Annual Plan describing its proposed 2022 Energy Transformation programs. Vermont's Renewable Energy Standard ("RES"), enacted through Act 56 in 2015, requires electric distribution utilities to either support fossil fuel savings by encouraging Energy Transformation ("Tier 3") projects or purchase additional Renewable Energy Credits ("RECs") from new, small, distributed renewable generators ("Tier 2").

VPPSA's Requirement

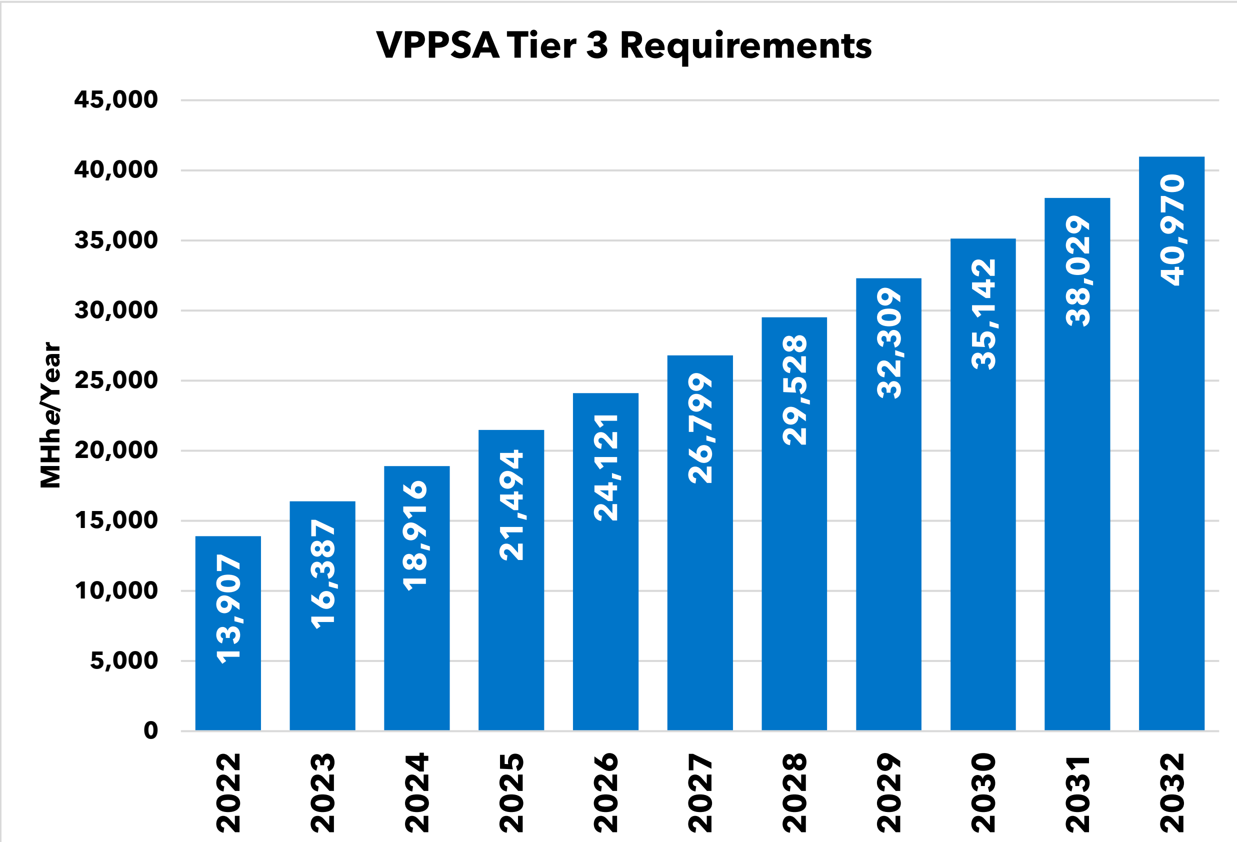
Utilities' Tier 3 requirements are established by 30 V.S.A. § 8005(a)(3)(B), which states that "in the case of a provider that is a municipal electric utility serving not more than 6,000 customers, the required amount shall be two percent of the provider's annual retail sales beginning on January 1, 2019.[1]" Tier 3 requirements increase by .67% annually.

In 2022, VPPSA's aggregate requirement is estimated to be 13,907 MWh equivalent in savings, representing 4% of annual retail sales. The 11 VPPSA member utilities plan to meet their Tier 3 requirements in aggregate, as permitted under 30 V.S.A. § 8004 (e), which states "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate."

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

[1] 30 V.S.A. § 8005(a)(3)(B)

The below chart represents VPPSA's projected annual MWh equivalent in savings through 2032.



Summary of 2021 Projects

VPPSA expects to meet its 2021 Tier 3 requirements of approximately 11,605 MWh through a combination of prescriptive and custom measures. Prescriptive measures included post-purchase rebates or instant discounts for:

1. Cold Climate Heat Pumps
2. Heat Pump Water Heaters
3. Electric and Plug-In Hybrid Vehicles
4. Electric Vehicle Chargers
5. Electric Forklifts
6. Electric Golf Carts
7. Residential Electric Lawn Mowers
8. Commercial Electric Lawn Mowers
9. Ebike and Retrofit Kits
10. Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers

Of the prescriptive rebates offered, cold climate heat pumps have had the greatest uptake. VPPSA's strategy continues to focus on cost-effective prescriptive and custom Tier 3 measures. VPPSA continues to observe that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is lower than both prescriptive incentives and Tier 2 RECs. Custom projects include incentives for line extensions and service upgrades that removed the need for diesel generators. Several custom projects were identified in 2021 but likely will not be completed until 2022 or later.

2022 Program Overview

VPPSA proposes meeting 2022 Tier 3 requirements in a manner that mitigates costs that could put upward pressure on electric rates. This includes a combination of prescriptive and custom measures and use of Tier 2 RECs if needed. The focus of VPPSA's offerings is on electrification measures that will benefit all ratepayers by bringing in additional revenue to the host utilities.

Prescriptive Measures

VPPSA intends to maintain its current portfolio of prescriptive measure offerings with a few additions. Savings are calculated using measure characterizations created by the Tier 3 Technical Advisory Group ("TAG.")

Electric Vehicles and Plug-In Hybrids

VPPSA will continue to offer customer incentives for the purchase or lease of EVs and PHEVs in 2022. The customer incentive for purchasing or leasing a new electric vehicle will be $1000 and the customer incentive for purchasing or leasing a new plug-in hybrid electric vehicle will be $500. Low-income customers[2] will receive an additional $400 towards the purchase or lease of an EV or PHEV.

VPPSA plans to continue incentives for purchasing used EVs and PHEVs. The customer incentive will be $500 for the purchase of a used EV and $250 for the purchase of a used PHEV.

Upfront cost has been identified as a major barrier to purchasing an electric vehicle. Beginning July 1, 2021, VPPSA piloted a point-of-sale incentive with two auto dealerships: Burlington Cars and Lamoille Valley Chevrolet. These dealerships were chosen due to their willingness to participate in a pilot and their proximity to VPPSA members.

VPPSA has chosen to expand this approach in 2022. VPPSA is currently engaging with vehicle dealerships around the state to offer a point-of-sale incentive. Customers who

[2] According to Rule 4.413, "A low-income customer shall be defined as a customer whose household income is at or below 80% of Vermont statewide median income."

purchase or lease a vehicle from a participating dealership will receive their incentive as an instant discount. The dealership will then submit to VPPSA for reimbursement.

Should an eligible customer purchase or lease a vehicle from a non-participating dealership, the option will still be available to receive a post-purchase rebate.

Electric Vehicle Charging

VPPSA will continue to offer a $500 rebate for customers installing electric vehicle chargers at a workplace and/or available for the public to use.

VPPSA is planning an EV Charging pilot for 2022 in conjunction with Efficiency Vermont ("EVT"). The pilot will provide free Level 2 charging equipment to some residential utility customers who purchase electric vehicles. The chargers that are provided will be equipped with Open Charge Point Protocol ("OCPP") meaning that they can be integrated with multiple control platforms through open-source technology. These EV chargers will initially be programmed to provide charging during off-peak hours and will facilitate direct control of EV charging in the future. This pilot will be offered in a subset of the VPPSA members' service territories in which VPPSA and EVT are conducting tailored programs in 2022.

Cold Climate Heat Pumps

VPPSA will continue to offer incentives on ductless and whole building heat pump technology. Efficiency Vermont will continue to administer point-of-sale heat pump incentives on VPPSA's behalf.

Ductless Heat Pumps:

VPPSA began offering downstream, post-purchase incentives for ductless heat pumps in 2019. Upon installation the customer would complete the rebate form, submit the application and supporting documents to VPPSA, and receive a check in the mail upon approval.

VPPSA collaborated with Efficiency Vermont and other Vermont distribution utilities to change the administration of the heat pump incentive beginning January 2021. In 2022, Efficiency Vermont will continue to administer the ductless heat pump incentive as an instant discount at the point-of-sale. The $250 utility incentive will be applied when a customer works through a participating contractor or distributor. Efficiency Vermont will batch the incentives applied in VPPSA member territories and invoice VPPSA monthly for reimbursement. VPPSA expects a similar volume of ductless heat pump incentives to what was offered in 2021.

VPPSA is also engaged in discussions with Efficiency Vermont and other Vermont electric utilities around the potential to offer ductless heat pumps to income-qualifying households at no cost to the utility customer. These incentives would be offered in tandem with weatherization services provided through the Weatherization Assistance Program ("WAP") to income eligible customers. The cost of the heat pumps will be split 50-50 between the distribution utilities and Efficiency Vermont through use of Act 151 funds. Consistent with the requirements of Act 151, the distribution utilities will claim the entire thermal savings for these CCHPs and EVT will claim the electric savings. This pilot envisions providing ductless CCHP to 150 Vermont households and VPPSA anticipates 11 of these will be installed in its member utility territories in 2022. Conversations with Efficiency Vermont and the WAPs are ongoing.

VPPSA will also be participating in an Efficiency Vermont pilot to promote integrated controls that are installed to ensure customers' ductless CCHPs are working efficiently with the buildings' central heating systems and thermostats. This is a downstream rebate offering up to $600 for integrated controls. VPPSA will fund $400 of this incentive and claim the thermal savings resulting from more efficient operations of the CCHP and central system. Efficiency Vermont has developed a custom savings tool to evaluate the electric and thermal savings values attributable to integrated controls and this tool will be shared with the Department of Public Service ("Department") in order to verify Tier 3 savings.

Whole Building Heat Pumps:
VPPSA will continue to offer incentives on centrally ducted heat pumps and air-to-water heat pumps. Beginning January 1, 2022, VPPSA will offer prescribed custom incentives for ground source heat pumps. Efficiency Vermont administers all whole building heat pump incentives on behalf of VPPSA and several other Vermont utilities.

The centrally ducted heat pump incentive will continue to be offered as an instant discount at the point-of-sale. The incentive amount ranges from $750 – $1,500 depending on the size of the heat pump.

Efficiency Vermont will continue to administer the post-purchase rebate available for air-to-water heat pumps. In most cases, VPPSA and Efficiency Vermont will each offer 50% of the $1,000/ton incentive and claim 50% of the thermal savings. When an air-to-water heat pump is installed in VGS territory, VPPSA will offer the full incentive and claim the full savings. This is equivalent to how the incentive was managed in 2021.

VPPSA will offer the statewide ground source heat pump ("GSHP") incentive beginning in 2022. The incentive offered will be $2,100/ton. Because ground source heat pumps are not characterized by the TAG, VPPSA is approaching these incentives on a prescribed custom basis. The incentive offering will remain constant at $2,100/ton while savings will be calculated using a tool developed by Efficiency Vermont that has been shared with the Department through the TAG.

Efficiency Vermont will batch the incentives and invoice VPPSA monthly for reimbursement.

Heat Pump + Weatherization:
VPPSA will continue to offer a $200 downstream incentive to customers who are installing heat pump technology in a weatherized building. The incentive applies to ductless, centrally ducted, and air-to-water heat pump technology.

If the customer wishes to receive the additional weatherization incentive, then they must fill out the Heat Pump + Weatherization rebate application form and submit it to VPPSA along with the necessary supporting documents. The additional incentive serves to highlight the importance of overall building performance. To be eligible for the higher incentive amount, customers will need to demonstrate that their homes were weatherized according to a list of standards developed and circulated by the Department during the CCHP measure characterization by the TAG.

VPPSA claims the incremental savings associated with a heat pump installed in a weatherized building. Currently there is a distinct measure characterization for ductless CCHP installed in a high performing (weatherized) building. VPPSA will advocate through the TAG to get distinct measure characterizations for WBHP (ducted, air to water, and GSHP) that are installed in weatherized buildings.

Heat Pump Water Heaters

VPPSA will continue to provide a $600 discount to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. This incentive is administered by Efficiency Vermont.

There are two pathways a customer can take to receive the incentive. The first scenario applies to customers working through a contractor. These customers may be eligible for an instant discount at the time of purchase. Efficiency Vermont provides a $650 discount at the distributor level. $600 is passed down through the contractor to the end use customer while $50 remains with the distributor as a stocking incentive. Efficiency Vermont batches incentives provided to distributors and end-use customers and bills VPPSA monthly.

In the second pathway the customer purchases a qualifying HPWH from a retail provider. The customer then completes and submits the appropriate Efficiency Vermont rebate form. VPPSA is billed monthly by EVT.

Approximately 75% percent of customers installing a new heat pump water heater are doing so to replace an electric water heater. In this instance, Efficiency Vermont pays the entire incentive and claims the electric efficiency savings. The remaining 25% of customers are replacing fossil fuel fired water heaters. VPPSA claims all the thermal savings associated with these energy transformation projects.

Forklifts

VPPSA continues to offer a $2,500 rebate incentive for customers that purchase a new electric forklift.

Golf Carts

VPPSA continues to offer a $100 rebate incentive for customers that purchase new electric golf carts.

Lawn Mowers

VPPSA will continue to offer both commercial and residential lawn mower incentives. The rebate for a residential lawn mower will continue to be $50. VPPSA will continue to offer a $1,000 incentive for commercial lawn mowers in 2022.

E-Bikes

VPPSA will continue to offer a rebate incentive of $100 for the purchase of a new e-bike or e-bike conversion kit.

Residential Yard Care

VPPSA introduced several new incentives in July 2021 through an amendment to the 2021 Annual Plan. The following rebates were added in 2021 and will be continued in 2022.

Leaf Blowers:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric leaf blower.

Trimmers:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric trimmer.

Chainsaws:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric chainsaw.

Custom Measures

Commercial and industrial ("C&I") customers will continue to be served on an individual, custom basis in 2022. VPPSA continues to explore cost-effective Tier 3 custom projects. Identified custom projects with estimated completion in 2022 include electric buses, commercial heat pump units for a new-construction multifamily unit, electric bucket trucks, and an industrial heat recapture project.

Due to the relatively lower cost of MWh savings from custom projects, VPPSA continues to focus on identifying opportunities and working with utility customers to engage in energy transformation. VPPSA has launched a Key Accounts program that will better enable identification of custom projects with C&I customers. Additionally, VPPSA continues to partner with Efficiency Vermont to identify C&I customers that have potential Tier 3 and electric efficiency projects. Incentives for custom measures are typically paid for by the host utility rather than through VPPSA, with the host utility retaining the associated Tier 3 credits. Upon approval of the VPPSA Board of Directors, VPPSA may fund custom projects through its Tier 3 budget and allocate the Tier 3 savings among its members.

VPPSA is currently partnering with WexEnergy to pilot their new product, WindowSkins. WexEnergy was a participant in the 2020 DeltaClime business accelerator program, which VPPSA sponsors. VPPSA staff mentored DeltaClime participants throughout the accelerator program as they pitched their innovative products designed to minimize heat loss through windows. The pilot program involves testing the WindowSkin product in municipal buildings and one industrial customer through the 2021/2022 heating season. The WindowSkins should assist the municipalities and industrial customer in lowering the amount of fossil fuel used to heat their buildings and meet internal energy goals.

VPPSA will continue to work with the Department on custom projects to ensure savings claims are verified and the Department is able to adequately budget for verification activities.

Tier 2 RECs

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

VPPSA is managing member Tier 3 compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier 2 RECs. Under this approach the Tier 2 REC price acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings. Should Tier 2 REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier 3 planning document.

Best Practices and Minimum Standards

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

VPPSA's most recent, Commission-approved IRP used the same underlying assumptions as VELCO's Long-Range Transmission Plan ("LRP"). As a result, they incorporate the State's latest outlook for EVs and CCHPs. These technology trends are still nascent and are significant inputs to the load forecast. However, according to the IRP load forecast analysis, they are not likely to cause any major deviations to the IRP, either this year or in the next three years.

VPPSA continues to monitor COVID-related load impacts, as well as the potential impacts of large, custom Tier 3 projects. To date, VPPSA has not identified any major deviations from its IRP load forecasts, especially in light of the high and low forecast cases that were analyzed in the IRPs.

VPPSA has established a partnership with Virtual Peaker, allowing us to assist our members in demand-response programming. In 2022, VPPSA will continue to use the platform for an internal utility behavioral demand-response program to strategically maximize load-reducing generation during high-cost time periods.

VPPSA's memorandum of understanding ("MOU") with Efficiency Vermont, which the PUC approved under Case 19-3272, continues through 2023. The VPPSA/Efficiency Vermont MOU includes the potential for an active demand response pilot. The utility economics of active load control remain a challenge, and involvement from Efficiency Vermont could help lower utility costs. VPPSA and Efficiency Vermont are in the early stages of discussing a load management program that would enable VPPSA member utilities to control multiple technologies through one integrated platform in order to overcome the cost barriers of utilizing distinct, proprietary platforms to manage each technology (e.g. EV chargers, CCHP, smart thermostats.) The OCPP pilot discussed above is a component of this demand management strategy and will mitigate the grid impacts of EV charging.

As discussed in the CCHP section of this plan, VPPSA is partnering with EVT on a pilot to promote integrated controls for CCHP. This pilot is expected to increase the fossil fuel savings from CCHP installations through more efficient integration with the buildings' central heating systems. This technology will also lay the groundwork for future load management of CCHP electric demand.

In addition, VPPSA is pursuing utility-scale storage as a cost-effective means of achieving demand reductions for its members. A Request for Proposals to install storage facilities sized between 100 kW and 4.9 MW within the VPPSA member utilities' service territories was issued in October 2020 and VPPSA has narrowed the selection down to a final vendor.

Finally, as noted in the discussion on prescriptive rebates, VPPSA provides an additional $200 heat pump incentive for units that are installed in weatherized buildings as a mechanism to encourage the installation of heat pumps in buildings that meet established performance standards.

Equitable Opportunity

VPPSA strives to ensure that Tier 3 programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier 3 incentives described in the Plan will be available to all VPPSA member utility customers. Commercial and Industrial customers have the ability to access VPPSA's prescriptive measures and are also served through custom incentives.

With some measures, such as EVs, VPPSA is providing a significantly higher incentive to income-eligible customers to help offset the upfront cost barrier of purchasing these vehicles. VPPSA also provides incentives on used EVs and PHEVs which come with a lower upfront cost to the customer.

Additionally, VPPSA is engaging with Efficiency Vermont and other electric utilities to offer ductless cold climate heat pumps to income-qualifying households at no cost to the utility customer. Please refer to the Cold Climate Heat Pump section of this plan for more details on this low-income program offering.

Financing is another tool that can be used to make Tier 3 measures accessible to customers. VPPSA is co-chairing an Energy Action Network subgroup to develop an on-bill tariff efficiency program through which customers could pay for their efficiency and Tier 3 measures on their electric bill. This program, which is being financed by Vermont Housing Finance Agency, will include robust incentives to low-income customers. The program is being structured such that participating customers' total monthly energy costs, including the on-bill tariff payment, will be the same or lower after making the efficiency upgrades than they were previously. This "revenue neutrality" is seen as a critical element for reaching lower income households.

In compliance with Rule 4.413 VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. Participation and spending are monitored and reviewed each year to inform program planning for future years.

Finally, VPPSA's Tier 3 programs have a deliberate emphasis on electrification. The ability to bring financial benefits to all customers, rather than just participating customers, makes electrification an attractive Tier 3 option from an equity perspective. If additional kWh can be procured at costs at or below the costs embedded in a utility's rates, increasing the number of kWh delivered through the utility's system allows the fixed costs of operating the utility to be recovered over a larger number of units, driving the per kWh rate down for all customers. In this way both participants and non-participants stand to benefit from VPPSA's Tier 3 programs and cost-shifting among customers is minimized.

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

Consistent with Commission Rule 4.413 (c), VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. This data is included in VPPSA's Tier 3 savings filed in March and RES Compliance Filing in August. Over the life of the RES, VPPSA intends to provide equitable opportunities to its customer sectors in rough proportion to each customer sector's annual retail sales.

Partnership, Collaboration, and Marketing

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

VPPSA continues to administer the VTrans income-qualifying electric vehicle incentive. The VTrans incentive is offered on the sale of any electric vehicle registered in Vermont. The value of the VTrans incentive is dependent upon the owner's household income level. Participating car dealers sell vehicles at a price reduced by the statewide incentive for eligible customers. Each dealer then submits the customer's information and vehicle details to VPPSA. VPPSA batches the incentives each month and sends the information to VTrans with a summary report and invoice. VTrans will pay VPPSA for the state incentive, which VPPSA will then remit to the dealer. In 2021 there was an increase in uptake of the income-qualifying VPPSA electric vehicle incentive.

The VPPSA/Efficiency Vermont MOU approved in 2019 has strengthened the partnership between the two organizations. In many cases, this partnership involves VPPSA providing incentives for electrification measures, which can provide benefits to all VPPSA utility customers, while Efficiency Vermont provides incentives for electric efficiency measures. With the exception of air-to-water heat pumps, there will be no prescriptive measures offered by VPPSA in 2022 for which costs and savings will be allocated between VPPSA and EVT. The allocation of savings and costs for joint custom commercial and industrial projects will be determined on a case-by-case basis. In general, savings allocated to each entity will be in proportion to the financial contribution to the specific project.

Under the MOU structure, VPPSA and Efficiency Vermont will implement tailored efforts in three VPPSA member communities each year of EVT's current performance period (2021-2023.) Morrisville Water & Light, Lyndonville Electric Department, and Hardwick Electric Department have been identified for 2022 Tailored Efforts. Additionally, as previously mentioned, VPPSA and Efficiency Vermont plan to partner on load management pilots.

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

- VPPSA member utility bill stuffers
- VPPSA member utility staff training
- VPPSA website
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops

- Car dealer outreach
- EVT contractor and distributor outreach
- Direct outreach to Key Account customers

Cost-Effectiveness

VPPSA's Tier 3 planning included consideration of the suite of measures in the 2022 Tier 3 Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA analyzed the inclusion of wood pellet stoves for 2022. This measure would have been delivered in conjunction with Efficiency Vermont and necessitated a 50/50 split of the thermal savings. The incentive and Tier 3 savings values for pellet stoves are included in the table below. Ultimately VPPSA decided not to include pellet stoves as a measure in 2022 because projections of electrification measures show that VPPSA's entire Tier 3 requirement is likely to be met through existing prescriptive programs. As described in the Equitable Opportunity section above, VPPSA's Tier 3 strategy prioritizes electrification measures that have the potential to bring financial benefits to all customers. VPPSA will re-visit the inclusion of pellet stoves in future Tier 3 planning cycles.

Measure	Incentive	MWh	Cost/MWh
Residential Pellet Stoves, Existing Home	$225.00	90.05	$2.50
Residential Pellet Stoves, New Construction	$225.00	40.46	$5.56

VPPSA has completed lifecycle cost analysis for its Tier 3 measures. Cost-effectiveness was evaluated based on both the Utility Cost Test ("UTC") and Societal Cost Test ("SCT"). Lifetime utility net costs are presented in the Summary Table of the Tier 3 Reporting template that accompanies this plan. Results of the SCT analysis are presented below. In future years, lifecycle analysis of VPPSA's Tier 3 programs will be included in the VPPSA members' Integrated Resource Plans.

Measure	Budgeted Incentive	Incremental Cost	Life (Years)
EV	$1,022	$15,708	8
PHEV	$650	$7,301	8
CCHP	$381	$3,293	15
WBHP	$1,535	$10,159	18

Utility Cost Test	Societal Cost Test
0.9	0.5
0.9	0.8
1.1	1.6
1.0	1.1

- EV
    - Both the UCT and the SCT are less than one.

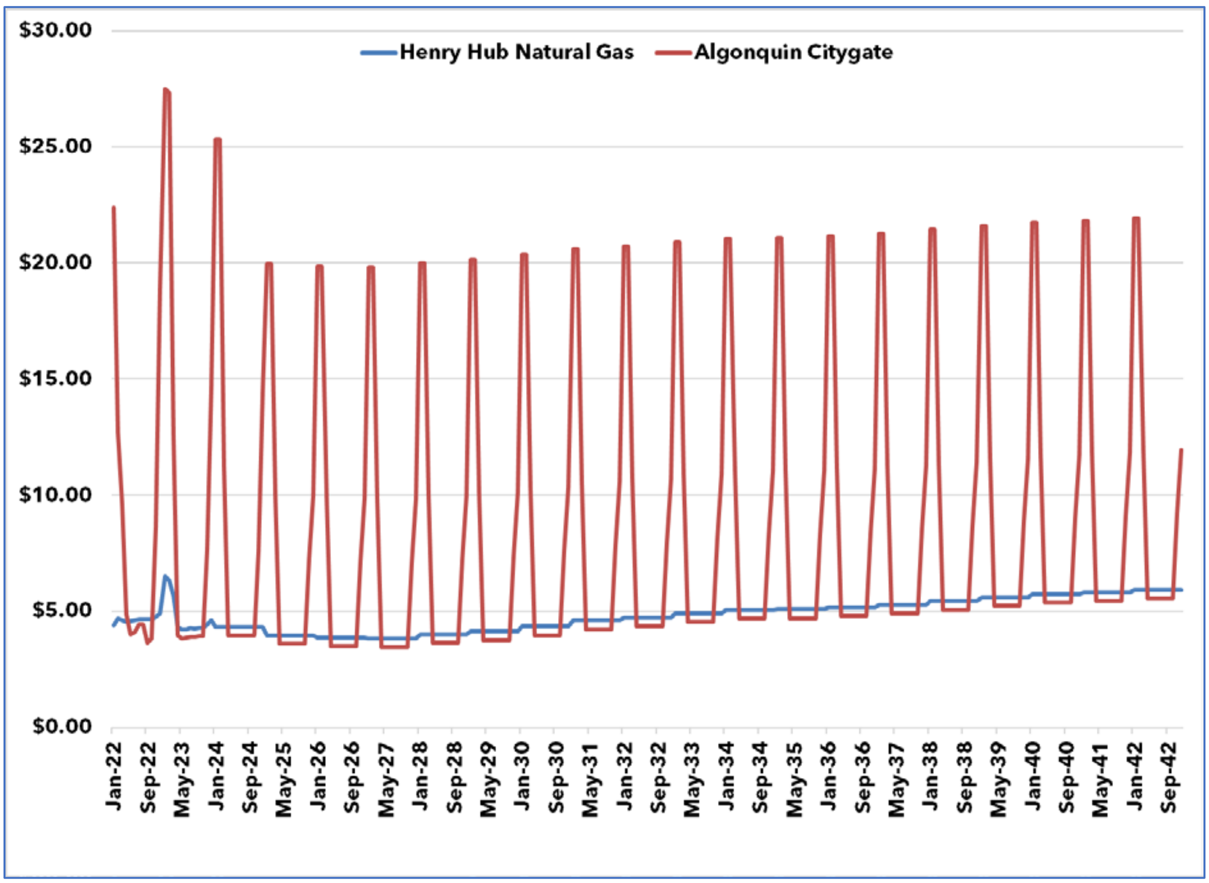
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- PHEV
    - Both the UCT and the SCT are less than one.
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- CCHP
    - Both the UCT and the SCT are greater than one.
    - This is due to a combination of a relatively low incremental costs and a relatively long measure life.
- WBHP
    - Both the UCT and the SCT are greater than one.
    - Incremental costs are relatively high for this measure, but the long measure life offsets it.
- Assumptions
    - Incentive levels match the VPPSA Tier III Budget.
    - Incremental costs and measure lives match the Tier III Planning Tool for 2022.
    - Seasonal on and off-peak load shapes (MWH and MW) are based on a combination of Itron, Cadmus and TAG working documents. Total MWH match the Tier III Planning Tool.
    - Avoided Costs for wholesale energy, capacity, transmission and RECs align with VPPSA's 2022 power budgeting assumptions.
    - Avoided fuels and carbon costs are from the AESC 2021 report.
    - The methods for calculating the UCT and SCT are from the EPA's National Action Plan for Energy Efficiency, 2009.

APPENDIX B: PRICING METHODOLOGY

ENERGY PRICING

Energy prices are forecast using a three-step method. First, a monthly natural gas price forecast is taken from broker quotes for the first two years of the forecast period. This includes both Henry Hub (HH) and Algonquin Citygate (AGT) prices, as well as NEPOOL electricity prices. Second, the AGT price is added to the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) HH forecast for the period 2025 to 2042. The forecast of HH and AGT prices can be seen in Figure 1.

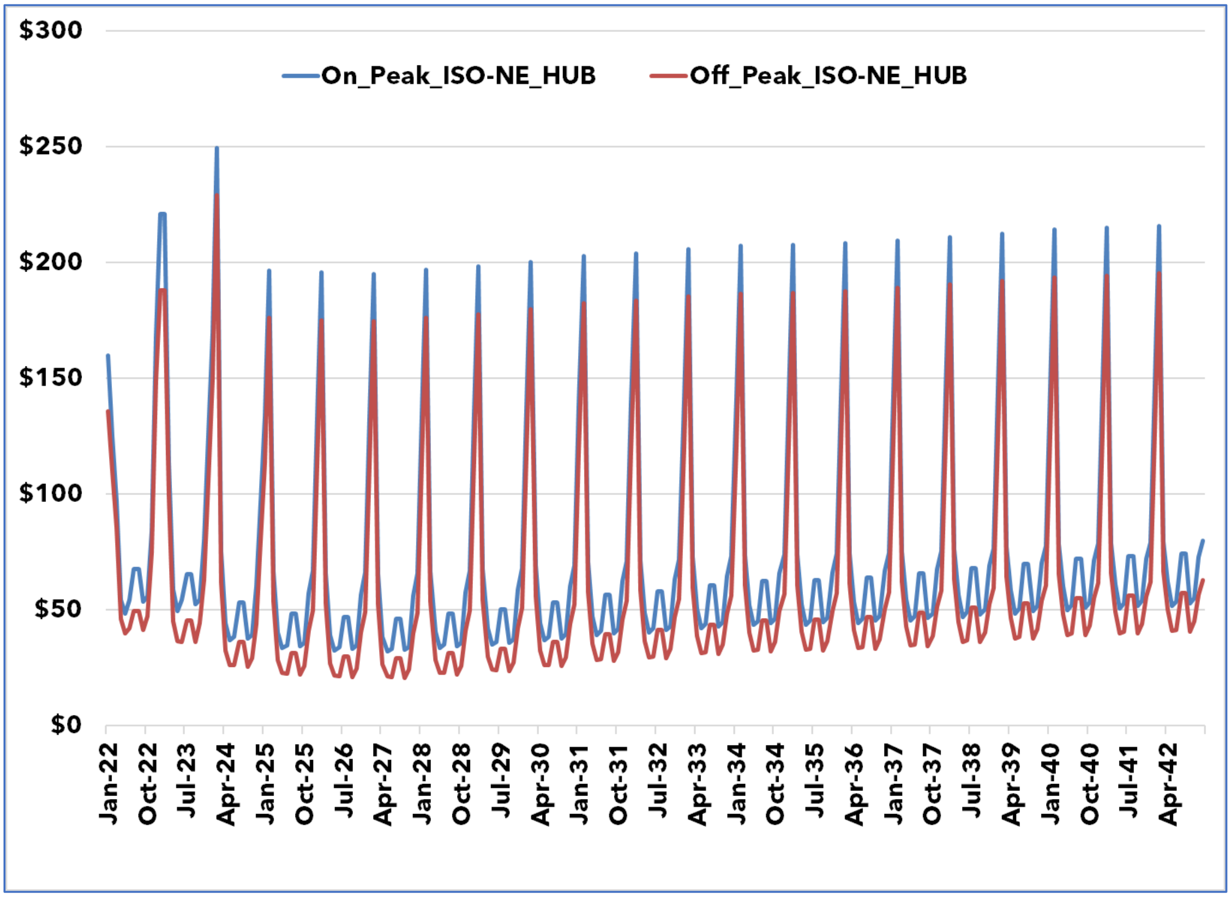
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Notice that the Henry Hub price is stable and inflationary, while the Algonquin Citygate price is high and volatile. This is due to the fact that New England's marginal gas supply is imported Liquified Natural Gas (LNG) during the winter months. LNG's price is subject to international supply and demand balances, and is the cause for the very high winter-time price outlook.

Third, we multiply the natural gas price forecast by the implied heat rate in the broker quote to get the on-peak electricity price. From this value, we subtract the spread between the on and off-peak prices to get the off-peak price. The results can be seen in Figure 2.

Figure 2: Electricity Price Forecast (Nominal $/MWH)

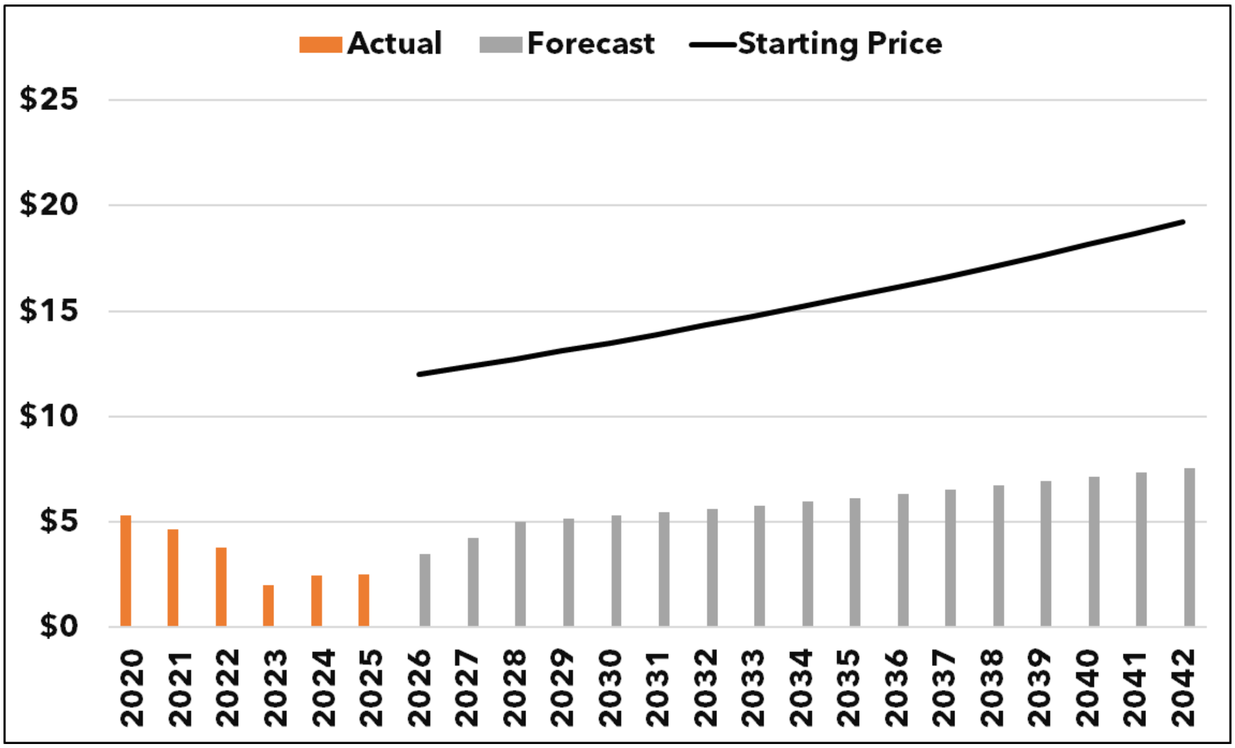


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of LED's load and resources.

CAPACITY PRICING

The capacity price forecast starts at $3.50/kW-month, which is the average of the last six years of actual auction results for the Northern New England Zone. Inflation is added to this value, which grows the capacity price to about $7.50/kW-month in 2042. Significant upside price risk does exist, as shown by the Maximum line in Figure 3. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 3: Capacity Price Forecast (Nominal $/kW-Month)



Village of Ludlow Electric Light Department 2017

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Ludlow Electric Light Department
Calendar year report covers	2017
Contact person	Howard R. Barton, Superintendent
Phone number	802-228-3721
Number of customers	3,749

System average interruption frequency index (SAIFI) = 1.2
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 0.3
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	3	14
2	**Weather**	3	36
3	**Company initiated outage**	2	8
4	**Equipment failure**	4	99
5	**Operator error**	0	0
6	**Accidents**	2	260
7	**Animals**	1	2
8	**Power supplier**	1	812
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	16	1,230

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

Village of Ludlow Electric Light 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	Village of Ludlow Electric Light Department
Calendar year report covers	2018
Contact person	Howard R. Barton, Superintendent
Phone number	802-228-3721
Number of customers	3796

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**2.3**
Customers average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**.58**

	Outage Cause	Number of Outages	Total Customer Hours Out
1	**Trees**	12	163
2	**Weather**	2	584
3	**Company initiated outage**	3	32
4	**Equipment failure**	2	4
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	7	152
8	**Power Supplier**	2	4100
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	**28**	**5035**

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

Village of Ludlow Electric Light Department 2019

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	Village of Ludlow Electric Light Department
Calendar year report covers	2019
Contact person	Howard R. Barton, Superintendent
Phone number	802-228-3721
Number of customers	3,786

System average interruption frequency index (SAIFI) = 0.1
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 0.9
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	5	34
2	**Weather**	2	80
3	**Company initiated outage**	0	0
4	**Equipment failure**	4	74
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	4	18
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	15	206

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

Village of Ludlow Electric Light Department 2020

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	Village of Ludlow Electric Light Department
Calendar year report covers	2020
Contact person	Howard R. Barton, Superintendent
Phone number	802-228-3721
Number of customers	3,818

System average interruption frequency index (SAIFI) = 1.1
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 0.3
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	5	40
2	**Weather**	1	10
3	**Company initiated outage**	0	0
4	**Equipment failure**	5	11
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	12	138
8	**Power supplier**	1	954
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	24	1,155

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

Village of Ludlow Electric Light Department 2021

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	Village of Ludlow Electric Light Department
Calendar year report covers	2021
Contact person	Howard R. Barton, Superintendent
Phone number	802-228-3721
Number of customers	3,818

System average interruption frequency index (SAIFI) = 0.0
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 0.9
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	2	23
2	**Weather**	1	4
3	**Company initiated outage**	0	0
4	**Equipment failure**	0	0
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	3	39
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	6	66

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

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

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Request for Proposal (RFP)

for an

Advanced Metering Infrastructure Solution

Deadline for Submission: March 4, 2020

Issued by Vermont Public Power Supply Authority
PO Box 126
5195 Waterbury-Stowe Road
Waterbury Center, VT 05677

Release Date: December 20, 2019

1. TECHNICAL REQUIREMENTS

1.1 Electric Meter Endpoints

This section defines the functional and technical requirements for new solid-state electric AMI revenue meters (AMI Meters) that shall be provided and deployed as part of this AMI project. VPPSA reserves the right to purchase one meter type or more than one meter type based on negotiations with the Vendor.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 6

Question	**Response:** Comply, No Comply or Alternative
1. AMI Electric Meters shall be new, solid state with no moving parts except for the minimum number of required to support service disconnect switching, tamper detection, and/or “hard” demand reset.	
2. Functional features of the new meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming is to be done at the factory according to utility specifications.	
3. AMI Electric Meters shall have a 20-year life.	
4. AMI Electric Meters shall be capable of recording total delivered and received energy measurement data in dedicated registers. Net energy is to be recorded in a dedicated register.	

5. AMI Electric Meters shall be capable of recording and storing interval data in interval lengths of 15, 30, or 60 minutes.	
6. AMI Electric Meters shall be capable of recording Time-of-Use (TOU) data.	
7. Demand quantity recorded in each register shall be configurable through programmable meter settings. Values stored in demand registers shall continuously increase until they are reset locally or via the AMI Network by an authorized AMI user.	
8. Meters registering peak demand shall support local resetting of the value (to zero) in any demand register.	
9. Meters shall feature security provisions that prevent local demand register resets by anyone other than authorized personnel.	
10. Programming of the AMI Electric Meters shall include an option to record either “rolling” or “block” interval demand values. Rolling demand subintervals shall include resolution of five (5) minutes, three (3) minutes, two (2) minutes or one (1) minute.	
11. AMI Electric Meters shall support KYZ data pulse (Form C) output.	
12. AMI Electric Meters must have the ability to provide “last gasp” notification of power outages within 30 seconds or less.	
13. All polyphase AMI meters shall auto-range when connected to services in the range of 120-277 Volts RMS, ± 20% with the exception that Form 12S must	

auto-range when connected to services in the range of 120-480 Volts RMS, ± 20%.	
14. The AMI Electric Meter shall be equipped with an industrial grade display capable of presenting at least five (5) reading digits, along with status enunciators and ID code numbers. The display shall include an easily interpreted graphic representing the magnitude and direction of energy quantities passing through the meter.	
15. Meters with an integrated service disconnect switch shall have an indicator that shows the status of the switch. The indicator shall be easily recognized, readily interpreted, and clearly visible to an observer viewing the meter.	
16. Meters equipped with a service switch shall perform reliably during continuous operation at the maximum load indicated on the meter's nameplate, while at minimum rated ambient temperature and humidity.	
17. Meters equipped with a service switch shall continuously monitor the service voltage on the customer side (load side) of the switch regardless of switch state. The meter shall generate an alert if voltage is present on a load terminal when the service switch is open.	
18. AMI Electric Meter display shall have an easily interpreted indicator showing the current status of the AMI Meter's AMI network connection. For example, the indicator may show the following states: • Network detected – connected • Network detected – not connected • No network detected • Transmitting	

• Receiving	
19. Meter displays may have an indicator that shows the TOU rate that is governing current TOU consumption registration in the meter.	
20. The meter nameplate shall include all applicable meter identification information. This information shall include a unique alphanumeric meter ID code (company number) specified by VPPSA, the manufacturer's name, the manufacturer's serial number, manufacturing date, bar coding, etc.	
21. Prior to delivery from the factory, the meter manufacturer shall test each meter to certify the accuracy and proper operation of the meter.	
22. A file with meter attribute information and test results shall be provided to VPPSA electronically prior to every shipment from the manufacturer.	
23. AMI Electric Meters provided shall not require any special equipment for shop or field-testing procedures. All testing should be capable of being conducted using standard, commercially available test equipment in both the field and the shop.	
24. All AMI Meters proposed shall feature a "test mode" that suspends normal meter operation so that consumption and demand measurements from tests are not recorded in the billing registers and/or interval data. All energy measurements and other measurements stored in the meter shall be unaffected by energy passing through the meter while in test mode.	

Provide detailed responses for the following questions:

1. Identify the specific make and model of AMI Electric Meters that support replacement of 100% of the meter population shown in Table 3. Note: actual number of meters to be ordered will be updated at the time of contract negotiations.
2. Provide a list of all alternate AMI Meters, by make and model, which currently work with the proposed AMI solution. Include a roadmap for future AMI Electric Meters that will be compatible with the AMI system.
3. Identify the electric quantities on all meter forms that the AMI meters are capable of measuring.
4. Provide a table that shows the relationship between number of channels, interval length, and days of storage in the proposed AMI Electric Meters. Describe the options to collect data in intervals shorter than 15-minutes.
5. Specify the number of TOU registers available.
6. Describe the process to perform a local demand reset in each proposed meter type.
7. Describe how the day/date/time of AMI Electric Meter is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Electric Meters time synchronized after an outage.
8. Describe the abilities of the proposed AMI Electric Meters and the AMI system to provide time-stamped voltage data, maximum and minimum voltage data, sag and swell events or counts, loss of voltage, etc. Describe the method of measuring voltage, average or RMS. Include the frequency of data retrieval from the AMI Meter by the AMI system (real time, daily, scheduled, or on request).
9. Describe if any meter components (service switch, display, communication board) are serviceable and/or replaceable by VPPSA and/or the Vendor.
10. Vendors shall describe how the “last gasp” notifications occur, or if they may be impeded by the loss of power to a Meter Collection Point (MCP).
11. Vendors shall describe how the “test mode” feature is activated and suspended on each of the proposed models of AMI Electric Meters
12. Provide a list and description of all alerts, events and notifications provided by the AMI Electric Meter. This should include tamper, outage and deviations from nominal AC voltage, frequency, and waveform.
13. Describe if power quality functions are running all the time, or how the AMI Electric Meter can be remotely reconfigured to turn on power quality monitoring when needed.
14. Describe the following service disconnect and reconnect features:

a. Describe both remote and local operation of the service switch, including "arming" features, if any, available with the proposed solution.

b. Specify the number of disconnect/reconnect cycles that the switch is rated to perform at full meter load.

c. Identify if the AMI Meters and/or Head-End System has a duty cycle monitor for the service switch.

d. What features are in place in the AMI Meter to keep the switch from repeatedly cycling open and closed.

e. Describe whether a "demand limiting" capability can be enabled via the AMI Network. This means that control of the switch can be configured to disconnect the service if demand exceeds a threshold value. Service shall be re-connected after a predetermined time interval or when the demand drops below the threshold value. Specify if and how the proposed solution allows the threshold and time interval values to be securely set locally and/or remotely over the network using the AMI Head-End System.

f. Describe at what voltage level the service switch will not close, if the service has been disconnected. Vendor shall describe if this voltage level can be specified by the utility and how it is set.

15. Describe the local communication software and methods between the AMI meters and staff who locally read and/or service the meter. Local communications may be with a radio interface, WiFi or an optically isolated connection accessible on the outside of the meter cover.

16. Describe the AMI Meter's internal memory. Vendor shall describe how the proposed AMI performs in the event of a communication failure and the AMI meter's ability to store data until communication has been re-established.

17. Describe the meter's program security provisions including but not limited to the following information:

a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

c. Explanation of the provisions securing communication with the meter via the meter's local communications portal(s) (optical and/or RF.

18. Describe the use of batteries, if any, in proposed AMI Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures.

19. Provide details of all metering compliance (ANSI, UL, IEC, etc.) and certifications.

20. Provide details of the failure rate for the proposed AMI Meters.

1.2 Water Meter Endpoints & Water System Features

VPPSA intends to place priority on utilizing existing water meters that already have touch-type registers and converting them to the AMI system being proposed. Where meters do not have AMI-compatible registers, proposer may elect to either replace registers with AMI-ready registers or replace entire meter with new AMI Water Meters which meet the standards and specifications outlined in this section.

The functional and technical requirements for the new AMI endpoints, known hereon as Meter Interface Units (MIUs). These MIUs shall be used to convert existing compliant water meters to AMI Water Meters. And, where necessary, new water meters shall be provided by the Vendor as part of this AMI project, inclusive of compatible MIUs. VPPSA reserves the right to purchase one meter type or more than one meter type based upon project needs and negotiations with the Vendor.

VPPSA members having water metering as part of this project generally have mechanical meters currently in place. These include, but not limited to, positive displacement, turbine and compound meters. Meters proposed in response to this RFP should be similar in size and measurement technology. More modern technologies, such as magnetic resonance, ultrasonic, or others, may be proposed and will be considered by VPPSA Members for use in this project.

For those VPPSA Members that have water meters as part of this project, the meters are generally located inside basements, utility closets, etc. Few will be located outdoors in meter pits or vaults. Vendor shall provide propagation analysis and outline installation considerations for proper operation and to maximize radio performance between the AMI Water Meter MIU and AMI MCPs.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 7

Question	Response: Comply, No Comply or Alternative

1. The AMI Water Meters provided as part of this solicitation shall be new meters meeting applicable AWWA and ANSI standards relative to type.	
2. Functional features of the new AMI Water Meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming shall be done at the factory according to utility specifications.	
3. AMI Water Meters and MIUs provided by vendor as part of this project shall have a 20-year life.	
4. All AMI Water Meters and MIUs together shall record total water delivered, detect reverse flow, and provide notification of alert conditions to the Head End system.	
5. The AMI Meters shall have the capability to record and store interval data in interval lengths of 15, 30, or 60 minutes.	
6. The AMI Water MIUs shall feature security provisions to prevent local reading, configuration or programming by anyone other than authorized personnel.	
7. New AMI Water Meter supplied for this project shall be equipped with registers capable of presenting at least eight digits, either digital or mechanical, and provide electronic features for scale output resolution.	
8. The meter nameplate shall include all applicable meter identification information. This information shall include, at minimum, a unique 8-digit numeric meter/register ID, manufacturer’s name, FCC data, manufacturing date, bar coding, etc.	

9. Prior to shipment from the factory, the meter manufacturer shall test each meter and certify the accuracy and proper operation of the meter to AWWA/ANSI standards for the specific type of water meters.	
10. A file with meter attribute information and test results shall be electronically provided to VPPSA prior to every shipment from the manufacturer that includes the following information about the delivery: 1) Water meter type 2) Water meter size 3) Water meter serial numbers 4) Water meter test results 5) Meter register types 6) Meter register ID numbers	
11. The meter shall not require any special equipment for shop or field-testing procedures. All standard test equipment can be used for testing in both the field and the shop.	
12. AMI Water Meter MIU has ability to be retrofitted to existing water meters that have touch pads (external on wall for indoor/basement meters).	
13. AMI Water Meter register output to the MIU is ASCII-based, serial communication, no pulse-based registers will be allowed.	
14. Communication from the AMI Water Meter register shall include the meter register's unique ID and current meter reading, at minimum.	
15. The Vendor shall provide clear instructions for the wiring connection between the radio transmitter and encoder registers. All wiring connectors or splices	

shall be tamper resistance providing signs that the wire has been tampered with or disconnected.	
16. AMI Water Meter registers shall record usage in US Gallons or Cubic Feet as determined during negotiations.	
17. New AMI Water Meter encoder registers shall display a minimum of eight digits (high resolution). The register shall be shipped factory programmed encoding all digits, a minimum of eight digits.	
18. New AMI Water Meter encoder registers should be programmable so that Member personnel may alter the meter reading configuration. This includes, but is not limited to, the number of digits in the reading.	
19. New AMI Water Meter encoder registers shall be attached to the meter body by a method that will prevent or discourage customers from tampering with the meter and register. The register terminal screw cap shall allow for the sealing of the terminal screws.	
20. The register shall have permanently stamped on the dial face the manufacturer, meter size, meter type, register type and unit of measure.	
21. The register shall have a low flow indicator visible on the face of the meter for use by the customer in the detection of a leak within the property.	
22. For new AMI Water Meters and MIUs, the Vendor shall supply a wire connector that is certified as an IP 68 connection, tamper proof and can be connected and disconnected without having to cut the wire or destroy the connector itself. There shall be no manual connections (e.g. gel caps) and there must	

be consistency among connectors across all meter brands provided. Where the connector needs to be installed or potted to the water meter register, it is the Vendor's responsibility to handle all communications, carrying costs and shipping costs imposed by the water meter register manufacturer(s).	

Provide detailed responses for the following questions:

<u>Meter Interface Units (MIUs)</u>

1. Identify the specific makes and models of MIUs that support conversion and/or replacement of 100% of the water meter population shown in Table 4. Note: actual number of MIUs and/or meters to be ordered will be updated at the time of contract negotiations.
2. Outline whether or not the proposed MIU has a multi-port option that will allow a multi-register AMI Water Meter to be read from a single MIU.
3. Provide a table that shows the relationship between datalogging interval and days of storage in the proposed AMI Water Meters. Describe the options to collect data in varying intervals, such as hourly, 30-minute, 15-minutes, etc.
4. Describe how the day/date/time of AMI Meters is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Meters time synchronized after a network outage, firmware updates, demand reads and commands (remote shut off, etc.).
5. Provide a list and description of all alerts, events and notifications provided by the AMI Water Meter. This should include battery level, wire tamper, reverse flow, register removal, magnetic tamper, leak detection.
6. Describe the leak detection functionality of the water meter MIU and how it will work with 6-digit registers that are part of the existing meter inventory.
7. Describe the local communication software and methods between the AMI Water Meters, MIUs and staff who locally read and/or service the water meter. Local communications shall be done using a wireless interface.

8. Describe the use of batteries in proposed AMI Water Meter MIUs. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures (if applicable). Describe how the low battery flag triggered, by a time-based calculation or by monitoring voltage?

9. Provide details regarding the typical and maximum expected failure rate for the proposed AMI Water Meters, registers and MIUs.

10. Describe the internal memory of the MIU. Vendor shall describe how the proposed AMI system performs in the event of a communication failure and the AMI Water Meter MIU's ability to store data until communication has been re-established.

11. Describe the MIU's programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.
    b. Explanation of how program access and change events are recorded by the MIU.

12. For indoor/basement water meter products, provide:
    a. Preferred mounting method of MIU (wall enclosure or flange).
    b. Two-wire and three-wire capability
    c. Describe how the MIU is to be connected to the AMI Water Meter register (e.g. splice, connector, etc.).

13. For pit-installed products, provide:
    a. Preferred mounting method.
    b. Minimum requirements of the meter pit lid (material construction, maximum thickness, depth of through the lid antenna recess necessary to make the antenna flush with the top of the lid and diameter of hole).
    c. Minimum clearance needed between the top of meter to bottom of pit lid.
    d. Describe how the radio is wired to the register (e.g. splice, connector).

14. Explain the provisions for securing communication with the meter via the meter's local communications portal(s) – optical and/or RF.

15. Provide MIU battery life warranty (in years). Describe the conditions of the warranty, such as if On-Demand Reads affect warranty terms, and if so to what extent.

16. Describe any other non-metering devices the AMI radio transmitter is compatible with.

<u>New AMI Water Meters & Registers</u>

17. Provide a table listing all AMI Water Meters being proposed by Vendor as part of this project. Include a listing of compatible AMI Water Meters indicating manufacturer, model and sizes, approved for use with the proposed AMI solution. Include any roadmap for future AMI Water Meters to be compatible with the proposed AMI system.
18. Provide details regarding the failure rate for the proposed AMI Water Meter registers.
19. Describe any provision for water service disconnect and reconnect options which may be incorporated in the water service:
    a. Describe both remote and local operation of the service disconnect functions.
    b. Specify the number of disconnect/reconnect cycles that the meter and MIU are capable of performing.
    c. Identify if the AMI Water Meter, MIU and/or Head-End System have a duty cycle monitor for the water service disconnect.
    d. What features are in place in the AMI Water Meter to keep the valve from repeatedly cycling open and closed or sticking.
    e. Describe whether a “flow-limiting” capability can be enabled via the AMI Network. This means that control of the service disconnect valve can be configured to provide limited water flow and be securely set locally and/or remotely over the network using the AMI Head-End System.
20. Describe the use of batteries in proposed AMI Water Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management practices and battery replacement procedures (if applicable).
21. Provide details of all meters regarding compliance with industry standards such as AWWA, ANSI, etc. Include any additional industry certifications.
22. Provide details regarding the failure rate for the proposed AMI Water Meters.
23. Describe the internal memory of the AMI Water Meter. Vendor shall describe how the proposed meter performs in the event of a communication failure between the meter register and MIU.
24. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.
25. Describe the meter’s programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

26. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

Remote Disconnect Water Meters & Leak Detection

27. Provide AMI Water Meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

1.3 AMI Network

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 8

Question	**Response:** Comply, No Comply or Alternative
1. AMI Solution shall use the same network for electric and water endpoints. The same MCPs will be used for both as well.	
2. AMI Network shall include two-way transport of data and commands between AMI endpoints and their respective AMI MCPs, which transfer the messages to/from the AMI Head-End System via the Vendor's proposed backhaul network.	
3. AMI System shall not rely on any collector device which may become a single point of failure for data retrieval of any specific endpoints.	

4. Authorized utility personnel shall be able to remotely access and modify all configurable AMI Meter programming/configuration parameters via the AMI Network.	
5. AMI System shall be IPv6 compliant.	
6. All elements of the proposed AMI Network shall support industry best practices for protection of data confidentiality, data integrity, and operational security.	
7. AMI Radio transmitters shall have multiple pathways to the Head End System with the intent of eliminating any single point of failure (redundancy).	

The following section includes the functional and technical requirements for interoperation of the AMI Head-End System, AMI Network, MCP's, and AMI MIU endpoints. If applicable, responses must include information for both AMI Electric Meters and AMI Water Meters. Please be sure that all responses cover both commodities (electric and water) where differentiation is necessary. VPPSA requires an AMI Network that will transport data and commands which support the proposed AMI functions at all AMI endpoints, in accordance with the functional and performance requirements specified throughout this RFP.

Provide detailed responses for the following questions:

1. Describe the proposed AMI Network and backhaul network provisions that will serve AMI endpoints. AMI endpoints will communicate with MCPs, and the MCPs will communicate directly with the Vendor's proposed backhaul network. Available fiber take-out points owned by VPPSA members are available, see Section 3 for background. Use of fiber for backhaul is preferred, wherever available.
2. Provide a network design showing the number and approximate location of MCP and/or Repeaters (if necessary) on a map of VPPSA member service territories. Use the GIS data provided in the files listed in Section 3.0. For purposes of sizing and configuring the network, assume the following baseline system activity:
    a. On-demand reading requests shall have an average response time of 30 seconds or less at least 90% of the time.

b. All polyphase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System three times within a 24 hour period.
c. All single-phase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System once every 24 hours.
d. The AMI Head-End System shall daily send 100 individual control message commands to AMI Meters with an integrated service switch to perform 50 connections or disconnections a day.
e. All AMI Meters will send outage notifications to the Head-End System as they occur.

3. Provide the percentage of total usable AMI network communication capacity Vendor expects to be used in the proposed AMI system under the baseline operating conditions described above. Additionally, Vendors shall predict the percent of network capacity utilized at the point in the AMI system with the least communication capacity and shall also recommend the maximum percentage loading that Vendor considers acceptable for VPPSA's intended uses of the AMI system.

4. Provide a proposed installation diagram that shows spacing requirements and where the MCP and associated equipment is to be placed on power poles, towers or other structures.

5. Provide the specification sheet for the MCP and associated equipment. Specifications must include how the MCPs will be powered and if there are any battery requirements or remote antennas needed. If multiple MCPs or external antenna versions are prescribed, then specification sheets will be included for each model variant.

6. All AMI firmware in the AMI Meters, Network devices, and customer premise devices, shall be remotely accessible for review, modification, and replacement over the AMI Network.

7. Describe how personnel will perform firmware upgrades (patches) using either the Head-End System or remote meter management software with the AMI Network. Clearly describe the AMI Meter's ability to sense, reverse, and report unauthorized or unsuccessful firmware replacements.

8. Describe how the AMI Radio transmitters will be read by more than one AMI data collector, providing MCP redundancy).

1.4 Head End System, Meter Data Management and Operations Software

VPPSA is seeking hosted software for both the Head-End System (HES) and Meter Data Management System (MDMD) functionality. The Proposer shall provide day to day support for the AMI solution. Seamless integration between HES and MDMS functions is expected.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 9

Question	**Response:** Comply, No Comply or Alternative
1. The Head End and Meter Data Management systems shall be established, well-proven, commercially available products based on widely adopted technology standards.	
2. The Head End Software shall manage all meter interrogations and communications for the AMI Network.	
3. The HES shall: • Accept and schedule readings based on the billing system scheduled reads file • Perform scheduled demand meter resets based on the billing system scheduled reads file • Provide a meter reading file for the billing system of scheduled reads • Report unread meters in scheduled routes/cycles • Reschedule unread scheduled readings for following day reading file for the billing system • Report on exceptions.	
4. The HES shall gather the billing data from 99% of the meters successfully read each day without estimation.	

5. The AMI System shall not fail to retrieve billing data from any single meter more than 15 consecutive days in the absence of a permanent AMI communication failure.	
6. Data stored in the AMI Meters and/or in the AMI Network shall be stored for a minimum of five-years from the day the data is first stored.	
7. The Head End Software and Meter Data Management Software shall be located in a Tier 3 datacenter, at minimum.	
8. The MDMS shall be capable of Validation, Estimation and Editing (VEE) prior to delivering data to a member's billing system.	
9. The MDMS shall provide a dashboard and reports showing the status of data by Member and aggregated for all VPPSA members.	
10. A Service Level Agreement for the defined Tier 3 datacenter 99.982% datacenter uptime availability shall be provided.	
11. The HES and MDM shall have disaster recovery services.	
12. The MDMS shall calculate Time-Of-Use billing determinants by rate class or for individual customers.	
13. The MDMS shall support any billing calculations required by VPPSA members, e.g. Critical Peak Pricing, Dynamic Pricing, Aggregated Load, Net Billing for solar groups.	
14. Support for the AMI Network and Wide Area Services shall be included in the support services.	
15. Backup services of all software, data and configurations shall be performed at least daily.	

16. Backups shall be stored off site in a geographic region different from the hosting data center.	
17. The HES and MDM databases must be encrypted.	
18. The Head End Software supports a multi-tenant solution where each tenant has its own separate data and application set, independent of other tenants.	
19. The Head End Software shall support each tenant executing the same application set, but shared among the various tenets	
20. The HES shall provide software keys to separate individual member's data, in addition to security built into meters.	
21. The Meter Data Management System shall provide software keys to separate individual members data, in addition to security features that are built into the proposed meters.	
22. User access shall be limited to individual member system's database.	
23. VPPSA Administrator's user credentials shall be configured to allow access all Member's system data.	
24. Individual VPPSA Members shall be allowed access to only individual member's meter and system data.	
25. For VPPSA Administrators, reporting shall be set to report on combination of individual Members system data, i.e. VPPSA wide statistics.	
26. Policies, safeguards, parameters and monitoring shall be in place to prevent unacceptable interference (performance, high workload) problems among tenants.	

Provide detailed responses for the following questions:

1. Provide a description of the features and functionality of the HES and MDMS (maximum of 2-pages for each system).
2. Provide screen shots of the Head-End System dashboard and key screens or reports available from the proposed Head-End system.
3. Provide details of daily procedures to manage meters, collectors, and network.
4. Provide details of procedures when there is failure of meters, collectors, and network.
5. Describe the Validation, Editing and Estimation available in the MDMS.
6. Describe the types of billing determinant calculations available in the MDMS.
7. Provide screen shots of the Meter Data Management System dashboard and key screens or reports available from the proposed MDMS.
8. Describe the Data Center(s) hosting the HES and MDMS. Include ownership, location, physical facilities, tier and security.
9. Provide a copy of the Service Level Agreement with the hosting data center.
10. Describe the type of hosting services provided such as: Infrastructure as a Service (IaaS), Platform as a Service (PaaS), Software as a Service (SaaS)
11. Describe the disaster recovery services and process.
12. Describe separately the multi-tenant features of the HES and the MDM including login levels, data security and encryption capabilities of the proposed system.
13. Describe the data protection and operational security provisions in the HES and MDMS.

1.5 Other Capabilities with the AMI System

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 10

Question	Response: Comply, No Comply or Alternative
1. The AMI System shall support a customer pre-payment function.	

2. The AMI System shall support the measurement of load from electro-technologies such as electric vehicles.	
3. The AMI System solution shall provide load control capabilities integral to the AMI system and software.	

Provide detailed responses for the following questions:

1. Explain any additional system functionality available today which would add value to the project.

VILLAGE OF LUDLOW ELECTRIC LIGHT DEPARTMENT 2022 LONG-TERM DEMAND FORECAST SUMMARY

The Village of Ludlow Electric Light Department (Ludlow) serves approximately 3,000 residential customers in the Village of Ludlow parts of Towns of Ludlow, Proctorsville, and Plymouth. Residential sector accounts for approximately 34% of sales, and small commercial customers 10% of sales. Several large C&I customers account for 55% of sales. Other sales which include street lighting is approximately 1% of sales.

Annual sales growth has averaged 1.1% with most of the sales growth occurring in the non-residential rate classes; C&I sales averaged 1.7% annual growth largely as result large jump in 2018 non-residential sales of 20.4% due to production expansion at one of Ludlow's largest customers. COVID-19 had a significant impact on sales contributing to strong residential sales growth of 6.1% in 2020 and non-residential sales decline of 13.5%. Table 1 shows historical customer and calendarized sales (sales converted from a billing cycle-basis to calendar-month basis.)

Table 1: Ludlow Historical Sales (Calendarized) and Customers

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2011	16,449		3,002		5,479		29,791		46,240	
2012	15,543	-5.5%	2,968	-1.1%	5,237	-4.4%	30,220	1.4%	45,763	-1.0%
2013	16,546	6.5%	2,996	0.9%	5,523	5.5%	31,665	4.8%	48,211	5.3%
2014	17,054	3.1%	3,041	1.5%	5,608	1.5%	29,323	-7.4%	46,377	-3.8%
2015	17,019	-0.2%	2,979	-2.0%	5,713	1.9%	29,178	-0.5%	46,197	-0.4%
2016	16,013	-5.9%	3,001	0.7%	5,336	-6.6%	30,473	4.4%	46,486	0.6%
2017	15,836	-1.1%	3,001	0.0%	5,277	-1.1%	31,329	2.8%	47,165	1.5%
2018	16,991	7.3%	3,045	1.5%	5,580	5.7%	37,720	20.4%	54,711	16.0%
2019	16,403	-3.5%	3,045	0.0%	5,387	-3.5%	38,454	1.9%	54,857	0.3%
2020	17,399	6.1%	3,071	0.9%	5,665	5.2%	33,257	-13.5%	50,656	-7.7%
2021	16,884	-3.0%	3,046	-0.8%	5,543	-2.2%	33,978	2.2%	50,862	0.4%
11-21		0.4%		0.2%		0.2%		1.7%		1.1%

Baseline Sales Forecast Models. The baseline forecast captures expected load growth before adjustments for new PV adoptions, and electric vehicle (EV) and cold climate heat pumps (CCHP). Baseline sales are driven by expected customer growth, state economic activity, end-use efficiency projections, temperature trends, and future energy efficiency program savings. Sales forecasts are derived from monthly regression models estimated using historical monthly billed sales and customer data from 2012 through 2021. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) specification that integrates end-use stock estimates that change slowly over time with variables that impact stock utilization such as weather conditions and economic activity. The SAE model is explained in the detailed report provided in Appendix A.

Economic Drivers. Residential customers and sales are based on Moody Analytics January 2022 Vermont economic forecast. Economic forecast drivers include number of households, household income, gross state output, and employment.

Efficiency and End-Use Saturations. End-use efficiency and saturations are derived from the 2020 Annual Energy Outlook (AEO) for the New England Census Division. Historical and projected residential saturations are adjusted to reflect Vermont where data is available. We assume commercial building energy intensities (measured in kWh per sqft) for Vermont are similar to that of New England. The forecast is further adjusted for state energy efficiency program savings derived from the current state Demand Resource Plan (DRP). Energy efficiency savings projections are allocated to Ludlow customer classes, based on Ludlow's share of state customer class sales; Ludlow accounts for 0.9% of state residential sales and 0.3% of commercial sales.

Weather. Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are derived from the Rutland Airport weather station. Since 1970, average temperatures have been increasing 0.08 degrees per year (0.8 degrees per decade) as measured at the Burlington International Airport. We assume temperatures continue to increase through the forecast period resulting in long-term decline in number of heating degree-days (HDD) and increase in number of cooling degree-days (CDD). Projected HDD and CDD are based on their historical twenty-year trends. For Rutland, expected number of HDD declines 0.7% per year, and CDD increase 1.3% per year.

A detailed description of the baseline model structure, and model inputs are included in Appendix A.

Baseline Results. For the forecast we assume large industrial activity is constant translating into flat long-term electric sales. Flat large C&I sales and decline in small commercial sales (driven by end-use efficiency improvements and targeted energy efficiency programs) results in 0.1% average annual decline in non-residential sales. Similarly in the residential sector, slow customer growth and declining residential usage results in 0.4% annual decline in baseline residential sales. Total baseline sales average 0.2% annual decline. Table 2 shows Ludlow baseline customer class forecast. Projected baseline sales (holding large C&I sales constant) are consistent with the prior ten years.

Table 2: Ludlow Baseline Sales Forecast

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2022	17,033		3,068		5,552		35,972		53,005	
2023	16,303	-4.3%	3,092	0.8%	5,273	-5.0%	36,968	2.8%	53,271	0.5%
2024	16,240	-0.4%	3,107	0.5%	5,228	-0.9%	36,973	0.0%	53,213	-0.1%
2025	16,098	-0.9%	3,117	0.3%	5,164	-1.2%	36,941	-0.1%	53,039	-0.3%
2026	16,020	-0.5%	3,126	0.3%	5,125	-0.8%	36,904	-0.1%	52,924	-0.2%
2027	15,930	-0.6%	3,133	0.2%	5,085	-0.8%	36,865	-0.1%	52,795	-0.2%
2028	15,897	-0.2%	3,139	0.2%	5,065	-0.4%	36,838	-0.1%	52,735	-0.1%
2029	15,858	-0.2%	3,144	0.2%	5,043	-0.4%	36,799	-0.1%	52,657	-0.1%
2030	15,834	-0.1%	3,150	0.2%	5,028	-0.3%	36,765	-0.1%	52,599	-0.1%
2031	15,811	-0.1%	3,153	0.1%	5,014	-0.3%	36,726	-0.1%	52,537	-0.1%
2032	15,807	0.0%	3,156	0.1%	5,008	-0.1%	36,702	-0.1%	52,508	-0.1%
2033	15,734	-0.5%	3,158	0.0%	4,983	-0.5%	36,655	-0.1%	52,389	-0.2%
2034	15,679	-0.3%	3,157	0.0%	4,967	-0.3%	36,620	-0.1%	52,299	-0.2%
2035	15,639	-0.3%	3,156	0.0%	4,955	-0.2%	36,586	-0.1%	52,225	-0.1%
2036	15,628	-0.1%	3,155	0.0%	4,954	0.0%	36,569	0.0%	52,197	-0.1%
2037	15,554	-0.5%	3,152	-0.1%	4,935	-0.4%	36,528	-0.1%	52,083	-0.2%
2038	15,485	-0.4%	3,148	-0.1%	4,919	-0.3%	36,499	-0.1%	51,985	-0.2%
2039	15,417	-0.4%	3,143	-0.1%	4,905	-0.3%	36,469	-0.1%	51,886	-0.2%
2040	15,378	-0.3%	3,138	-0.2%	4,900	-0.1%	36,440	-0.1%	51,818	-0.1%
2041	15,295	-0.5%	3,132	-0.2%	4,883	-0.3%	36,390	-0.1%	51,686	-0.3%
2042	15,239	-0.4%	3,126	-0.2%	4,876	-0.2%	36,353	-0.1%	51,592	-0.2%
22-32		-0.7%		0.3%		-1.0%		0.2%		-0.1%
32-42		-0.4%		-0.1%		-0.3%		-0.1%		-0.2%

Electrification. Future electricity sales and demand growth will largely be driven by state electrification programs designed to reduce state greenhouse gas emissions. Two of the primary targets are heating – converting fossil fuel heat to cold climate heat pumps (CCHP) and Electric Vehicles (EV). The state through VEIC and state utilities are promoting the adoption of CCHP and EVs through rebates, low-interest loans, and building out electric vehicle infrastructure. Expected increase in behind the meter solar adoption (PV) mitigates some of this growth. The statewide forecast of these technologies (CCHP, EV, and PV) were developed through a collaborative process as part of the Vermont Electric Power Company (VELCO) 2021 Long-Term Transmission Plan. Forecast contributors include the Department of Public Service (DPS), the Vermont Energy Investment Company (VEIC), state utilities, and other state stakeholders. Work will begin later this year to update the state long-term forecast. We expect even stronger electrification sales growth as a result of recently passed Vermont Climate Action Plan.

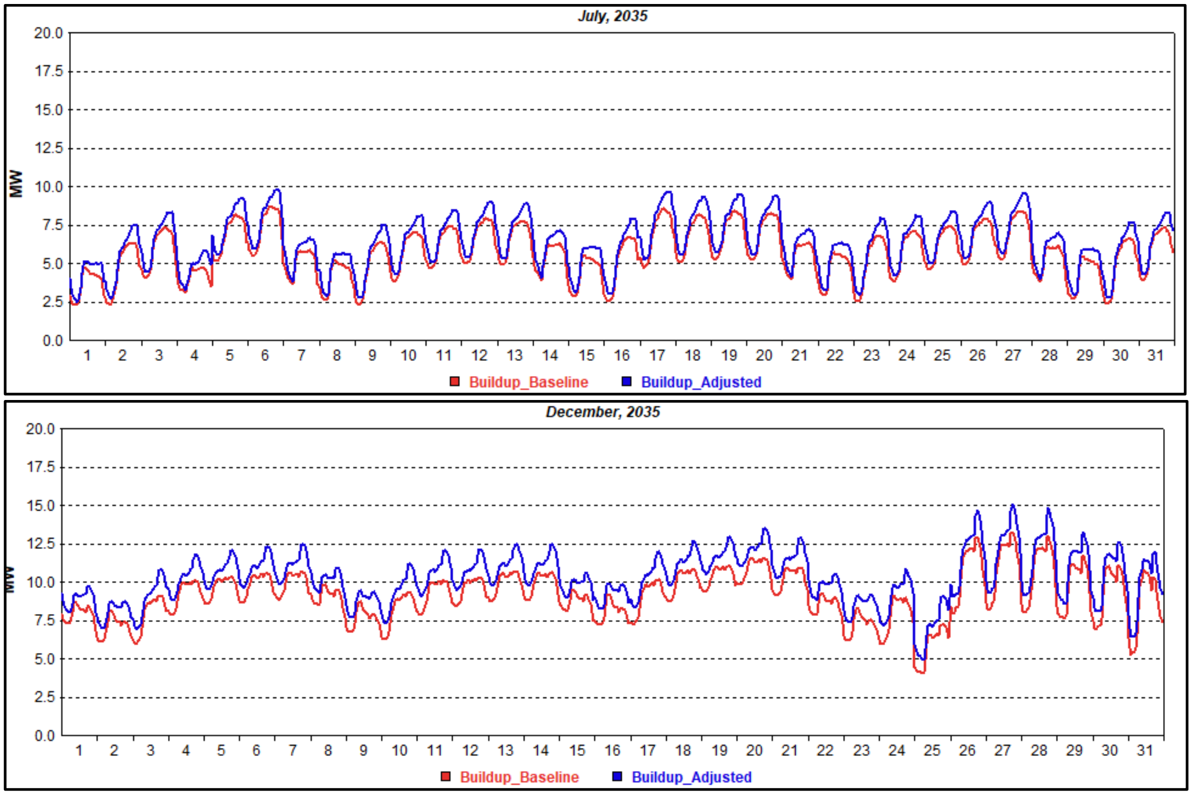
CCHP, EV, and PV forecasts are derived by allocating the state forecast based on Ludlow's share of state residential and commercial customers. Table 3 shows the resulting forecast.

Table 3: EV, PV, and CCHP Forecast

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	21	11	54
2023	48	24	114
2024	85	38	179
2025	131	46	248
2026	192	50	322
2027	269	54	402
2028	366	56	487
2029	487	56	578
2030	634	58	664
2031	806	60	738
2032	1,004	63	808
2033	1,220	64	875
2034	1,445	65	942
2035	1,668	65	1,009
2036	1,876	66	1,078
2037	2,059	66	1,147
2038	2,212	67	1,216
2039	2,332	68	1,285
2040	2,424	68	1,354
2041	2,491	69	1,424
2042	2,539	70	1,495

The adjusted load forecast is generated by adding the EV and CCHP hourly load forecasts and subtracting the PV hourly load forecast from the baseline hourly load forecast. Hourly technology and baseline forecasts are derived by combining energy and peak forecasts with hourly load profiles. The baseline hourly profile is derived from historical hourly system load data and EV, CCHP, and PV load profiles were developed as part of the VELCO Long-Term Transmission Plan Forecast. Figure 1 shows the baseline and adjusted hourly load forecast for July and December 2035.

Figure 1: Baseline and Adjusted Hourly Load Forecast



Energy and peak demand forecasts are derived from the adjusted hourly load forecasts. Tables 4 to 6 show forecast energy and coincident peak demand for baseline and each technology.

Table 4: Ludlow Energy Forecast (MWh)

Energy (MWh)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	55,216		70	-15	118	55,388	
2023	55,493	0.5%	163	-34	248	55,870	0.9%
2024	55,432	-0.1%	285	-52	388	56,053	0.3%
2025	55,251	-0.3%	445	-64	538	56,170	0.2%
2026	55,131	-0.2%	652	-69	698	56,412	0.4%
2027	54,997	-0.2%	917	-74	869	56,709	0.5%
2028	54,934	-0.1%	1,252	-77	1,052	57,161	0.8%
2029	54,853	-0.1%	1,670	-78	1,246	57,690	0.9%
2030	54,793	-0.1%	2,178	-80	1,431	58,321	1.1%
2031	54,728	-0.1%	2,777	-83	1,588	59,010	1.2%
2032	54,698	-0.1%	3,464	-87	1,739	59,814	1.4%
2033	54,574	-0.2%	4,218	-88	1,881	60,585	1.3%
2034	54,480	-0.2%	5,005	-90	2,024	61,420	1.4%
2035	54,403	-0.1%	5,786	-90	2,167	62,266	1.4%
2036	54,373	-0.1%	6,517	-92	2,313	63,112	1.4%
2037	54,255	-0.2%	7,161	-92	2,459	63,782	1.1%
2038	54,153	-0.2%	7,696	-93	2,606	64,361	0.9%
2039	54,049	-0.2%	8,117	-94	2,753	64,826	0.7%
2040	53,979	-0.1%	8,435	-95	2,901	65,220	0.6%
2041	53,841	-0.3%	8,667	-96	3,056	65,468	0.4%
2042	53,743	-0.2%	8,829	-97	3,220	65,695	0.3%
22-42		**-0.1%**					**0.9%**

Table 5: Ludlow Summer Peak Forecast (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	8.03		0.01	0.00	0.01	8.05	
2023	8.45	5.2%	0.01	-0.01	0.03	8.47	5.3%
2024	8.32	-1.5%	0.02	-0.02	0.04	8.36	-1.3%
2025	8.32	0.1%	0.04	-0.01	0.06	8.42	0.7%
2026	8.42	1.2%	0.05	-0.02	0.07	8.52	1.2%
2027	8.38	-0.5%	0.06	-0.01	0.09	8.52	0.0%
2028	8.44	0.8%	0.22	0.00	0.10	8.76	2.8%
2029	8.43	-0.2%	0.30	0.00	0.12	8.84	0.9%
2030	8.37	-0.8%	0.39	0.00	0.14	8.88	0.5%
2031	8.36	0.0%	0.49	0.00	0.17	9.02	1.6%
2032	8.37	0.1%	0.69	0.00	0.16	9.22	2.2%
2033	8.51	1.7%	0.85	0.00	0.17	9.53	3.3%
2034	8.60	1.1%	1.01	0.00	0.18	9.79	2.8%
2035	8.60	0.0%	1.16	0.00	0.19	9.96	1.7%
2036	8.62	0.2%	1.30	0.00	0.23	10.15	2.0%
2037	8.66	0.5%	1.44	0.00	0.22	10.32	1.7%
2038	8.63	-0.4%	1.55	0.00	0.23	10.40	0.8%
2039	8.78	1.8%	1.63	0.00	0.24	10.65	2.4%
2040	8.83	0.6%	1.69	0.00	0.26	10.78	1.2%
2041	8.78	-0.6%	1.74	0.00	0.27	10.79	0.1%
2042	8.73	-0.6%	1.77	0.00	0.32	10.82	0.3%
22-42		**0.4%**					**1.5%**

Table 6: Ludlow Winter Peak Forecast (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	13.35		0.00	0.00	0.04	13.39	
2023	13.72	2.8%	0.04	0.00	0.05	13.81	3.1%
2024	13.70	-0.2%	0.07	0.00	0.07	13.84	0.2%
2025	13.65	-0.3%	0.11	0.00	0.13	13.89	0.4%
2026	13.61	-0.3%	0.15	0.00	0.22	13.99	0.7%
2027	13.57	-0.3%	0.22	0.00	0.20	13.99	0.0%
2028	13.54	-0.2%	0.29	0.00	0.26	14.09	0.7%
2029	13.50	-0.3%	0.39	0.00	0.24	14.14	0.4%
2030	13.47	-0.3%	0.51	0.00	0.28	14.26	0.9%
2031	13.43	-0.3%	0.66	0.00	0.39	14.47	1.5%
2032	13.40	-0.2%	0.81	0.00	0.42	14.64	1.1%
2033	13.36	-0.3%	1.00	0.00	0.44	14.80	1.1%
2034	13.32	-0.3%	1.18	0.00	0.39	14.89	0.7%
2035	13.29	-0.3%	1.36	0.00	0.42	15.07	1.2%
2036	13.25	-0.2%	1.53	0.00	0.49	15.28	1.4%
2037	13.21	-0.3%	1.69	0.00	0.79	15.68	2.7%
2038	13.17	-0.3%	1.82	0.00	0.61	15.59	-0.6%
2039	12.86	-2.3%	1.91	0.00	0.93	15.71	0.7%
2040	13.09	1.7%	1.98	0.00	0.56	15.63	-0.5%
2041	13.04	-0.4%	2.04	0.00	0.59	15.67	0.3%
2042	12.99	-0.3%	2.08	0.00	0.78	15.86	1.2%
22-42		**-0.1%**					**0.9%**

APPENDIX A: VPPSA Long-Term Demand Forecast

LUDLOW ELECTRIC DEPARTMENT
LUDLOW, VERMONT

TRANSMISSION AND DISTRIBUTION SYSTEM STUDY

NOVEMBER 2019

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LUDLOW ELECTRIC DEPARTMENT
LUDLOW, VERMONT

TRANSMISSION AND DISTRIBUTION SYSTEM STUDY
NOVEMBER 2019

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LUDLOW ELECTRIC DEPARTMENT

LUDLOW, VERMONT

TRANSMISSION AND DISTRIBUTION SYSTEM STUDY

NOVEMBER 2019

1.0 Overview of Study

A Distribution System Planning Study was performed for the Ludlow Electric Department (LED). The study included a review of the LED's transmission system, substations, and distribution feeders. The major focus of the study was to:

- Identify current deficiencies (based on present demand load level).
- Review system performance at future projected (year 2039) demand load level.
- In addition to PLM's experience, evaluation of the LED system was based on guidance and concepts found in relevant State regulatory documents, including the 2016 Vermont Comprehensive Energy Plan and the 2005 Vermont Electric Plan.
- Net Present Value of Revenue Requirement calculations were performed in order to evaluate T&D system upgrades with respect to potential loss savings.
- Based on the above, provide recommendations for near term upgrades (justified by existing conditions or currently planned load increases) as well as a Long Range Plan for the LED system.

2.0 Summary of Findings and Recommendations

The LED system has six (6) 12.47 kV distribution feeders which serve a winter peaking load. The all-time system peak demand of 13.058 MW occurred during winter 2018. The previous all-time system peak demand value of 12.871 MW was recorded during winter 2006.

The Vermont Public Power Supply Authority (VPPSA) had recently developed a 20-year peak demand forecast for the LED system as part of its Integrated Resource Planning and that forecast was used for this study. The forecasted value for 2019 (December) was 13.41 MW. Peak demand is projected to increase to 14.55 MW by the year 2039.

A review of the existing LED system (including visual observations and discussions with LED personnel) indicates that the system is generally in good physical condition, operating efficiently, and able to provide reliable power to all customers in the service territory now and throughout the study period. All customers are supplied via the regulated 12.47 kV distribution system. All substation equipment and line conductors are operating within their thermal limits.

As part of this review, various types of system efficiency improvements that could potentially decrease I^2R losses were considered, including those listed in the 2005 Vermont Electric Plan. Using a twenty-year net present value of revenue requirement analysis, the dollar value of the predicted kW and kWh savings was used in order to determine the maximum cost expenditure that would be supported by the savings. The maximum expenditure was then compared to the estimated cost of implementation in order to make an appropriate recommendation as to whether or not to proceed. The value of the projected loss savings for all recommended system improvements was determined and noted, whether or not the project was fully justified by the reduced losses. A spreadsheet summarizing the results of the loss savings analysis that was performed as part of this study is included as Appendix E. Typical system improvements that may result in loss savings are discussed in detail in Section 9.0.

2.1 Recommended Near Term Improvements

Recommended near term system improvements that were identified by this study include:

- Implement updated substation voltage regulator settings (reflecting present system configuration and anticipated load levels)
- Install additional power factor correction capacitors on the Smithville and Lake feeders
- Perform phase load balancing on the Lake feeder
- Replace the feeder circuit breaker at the Smithville substation with a circuit recloser (due to having reached the end of its expected service life).

2.2 Longer Term Considerations

While there are presently no operating issues, the LED will need to budget and plan for the replacement of the substation transformer and six voltage regulators at the Route 103 substation. This equipment will likely reach the end of its expected service life during the 20 year study period.

2.3 LED Planned Distribution Line Relocation Project

As a planned event needed to address issues of aging facilities, river bank erosion and providing improved access for service restoration, the LED will be rebuilding and relocating approximately 1.2 miles of three-phase 12.47 kV distribution line on the branch of the Smithville feeder that feeds the village of Proctorsville and vicinity. The line section to be replaced runs from East Hill Rd. in Ludlow to Main St. in Proctorsville. The existing line runs behind a field and along the edge of the Black River and then along a railroad corridor. It is difficult to access during winter and may require railroad permission, adversely impacting restoration time and system reliability. LED Is proposing to relocate this line so that it runs along Route 103, providing year-round access from standard bucket trucks. LED is in the process of securing any necessary easements from the abutters. The is some existing single phase distribution running along Route 103, so the new line would effectively be filling in the gaps. The existing line utilizes a combination of #2 and 1/0 AWG conductor. The relocated line will be constructed using 4/0 AL spacer cable conductor, which is consistent with LED's standard construction practices for three-phase mainline. The system model indicates that the project will result in 0.8 kW of loss savings at time of system peak demand.

An existing pole mounted circuit recloser sectionalizes this portion of the line for faults toward Proctorsville. The existing circuit recloser is reaching the end of its service life and will not be relocated. A new circuit recloser will be installed as part of this project.

2.4 Additional Load at Okemo Mountain Resort

2.4.1 The Okemo Mountain Resort (OMR) has indicated to the LED that they plan to install two new chair lifts. A lift with a 600 HP motor is proposed for the Okemo base area (supplied by the High St. feeder). A lift with a 800 HP motor is proposed for the Jackson Gore area (supplied by the Jackson Gore feeder). Existing OMR lifts with motors of this HP size are presently supplied by the LED 12.47 kV system with no motor starting or operational issues. The affected feeders and substations have thermal capacity available to interconnect these new loads.

2.4.2 The OMR is considering replacing its diesel powered air compressors that are used for snowmaking with electric compressors. Preliminary discussions indicate that there could be three (3) 1000 HP +/- motors, which would add 2.2 MW +/- of demand to the LED system. The motors would be located on a portion of the LED system that is presently supplied by the High St. feeder and the Commonwealth Ave. substation. The OMR may not have completed its internal analysis and specific motor operating characteristics have not yet been made available to LED. The LED system as presently configured may not be able to support a load addition of this magnitude. Should the OMR elect to move forward, it will be necessary to perform a T&D system impact study that focuses specifically on the interconnection of this equipment.

3.0 System Description

3.1 Service Territory and Customer Base

The LED is a municipal utility providing service to approximately 3750 customers (metered accounts) in the Village of Ludlow and the towns of Ludlow, Plymouth, Proctorsville and Mt. Holly, Vermont. Residential customers make up about 80% of the customer mix while accounting for about one-third of retail kWH sales. Four large customers account for almost 40% of retail kWH sales with the remaining 30% of retail sales going to small to medium commercial and public authority customers.

The LED owns and operates approximately 1/2 mile of overhead 46 kV transmission lines, approximately 65 miles of 12.47 kV overhead distribution lines, and three electrical substations. The area covered by the service territory is approximately 23 square miles.

The primary industries located within the service territory are the Okemo Mountain Resort (OMR), supporting local services related to OMR, and Imerys Talc (Imerys).

3.2 46 kV Transmission

The LED receives 46 kV transmission service from Green Mountain Power (GMP). Each of the LED's three substations is connected to a 46 kV line that is owned by GMP. The GMP line has a source at each end, at the GMP Mt. Holly and Cavendish substations.

The LED owns and operates short radial taps of the GMP 46 kV line that supply each of its substations. The total length of 46 kV transmission owned by LED is approximately 0.35 miles. The tap to the Commonwealth substation is the longest and utilizes #1 copper conductor. The short tap to the Route 103 substation utilizes 4/0 ACSR conductor. The short tap to the Smithville substation utilizes 477 kcmil ACSR conductor.

3.3 46 kV to 12.47 kV Substations

The LED's three distribution substations are of an outdoor open bus style. Each substation has a single power transformer. Each distribution feeder has its own circuit breaker or circuit recloser and voltage regulators.

3.3.1 Route 103 Substation

The Route 103 substation is located on Cross Rd. (a.k.a. Megawatt Ln.) in the town of Ludlow. This substation incorporates a single 10/12.47/14 MVA main power transformer and three (3) 12.47 kV feeder positions, each with its own circuit recloser and set of three voltage regulators. The feeders are designated Lake, Solitude and Jackson Gore, which corresponds to the geographical areas that they serve. The circuit reclosers are capable of monitoring and storing ampere demand and operations information. Only the newest set of voltage regulators is capable of monitoring and storing ampere demand and power factor information. The substation supplies the northern end of the LED system, including the Solitude and Jackson Gore areas of the OMR.

3.3.2 Commonwealth Substation

The Commonwealth substation is located on Commonwealth Ave. in the town of Ludlow. This substation incorporates a single 9/12/15 MVA main power transformer and two (2) 12.47 kV feeder positions, each with its own circuit recloser and set of three voltage regulators. The feeders are designated Main (St.) and High (St.), which corresponds to their physical routing. The circuit reclosers are capable of monitoring and storing ampere demand and operations information and the voltage regulators are capable of monitoring and storing ampere demand and power factor information. The substation supplies the central portion of the LED system, including the Village of Ludlow and significant portions of the OMR. A small amount of GMP load (the Southface development on Okemo Mountain) is being temporarily supplied by this substation while GMP constructs a three phase line extension on its system.

3.3.3 Smithville Substation

The Smithville substation is located on Deroo Ln. in the town of Ludlow. This substation incorporates a single 11/14 MVA main power transformer and one 12.47 kV feeder position with its own circuit breaker and set of three voltage regulators. The voltage regulators were recently upgraded and are capable of monitoring and storing ampere demand and power factor information. The feeder circuit breaker is of an older design and its replacement with a modern circuit recloser should be considered. The substation supplies the southeastern portion of the LED system, including Imerys. The substation is shared with GMP and it supplies both LED and GMP distribution load

3.4 Distribution Feeders

The LED operates a total of six (6) regulated 12.47 kV distribution feeders. The distribution system has been fully converted to 12.47/7.2 kV (four-wire) operation. The distribution system is generally in good physical condition and has been properly maintained.

Overhead feeder mainline is typically 4/0 15 kV spacer cable or 4/0 ACSR on crossarms. Overhead branch circuits are typically constructed using 1/0 ACSR.

Underground feeder mainline is typically 500 kcmil aluminum 15 kV cable and this is typical of the underground circuits that supply significant portions of the OMR. 500 kcmil copper 15 kV cable was used for the recent upgrade of the Smithville feeder, which provided additional capacity and an associated incremental loss savings benefit.

3.5 Pole Mounted Circuit Reclosers

The LED distribution system incorporates five (5) mid-feeder pole mounted circuit reclosers. These provide automatic sectionalizing capability to reduce the number of customers affected by a fault beyond the recloser.

Two of these (designated Trailside and Okemo Base) are located on Okemo Ridge Rd. These protect customers served by the Main and High feeders in the Village of Ludlow from disturbances occurring further up on the mountain.

The Smithville feeder bifurcates in several directions incorporates three pole mounted reclosers. The Industrial Sites and Proctorsville reclosers isolate the respective portions of the feeder. The Imerys recloser isolates the customer-owned equipment at the Imerys manufacturing facility.

3.6 Power Factor Correction

The LED system presently includes 12 pole-mounted capacitor banks located on its 12.5 kV distribution feeders. These provide a total of 4.5 MVAR of reactive power which resulted in a power factor of 0.99 at the time of the system overall coincident peak demand. A combination of fixed and switched banks is used to follow the characteristics of the load. A list of the existing distribution system capacitors is attached as Appendix A.

3.7 Internal Generation

The LED does not own or operate any internal generation.

3.8 System One-Line Diagram and 12.5 kV Feeder Tie Capability

A one-line diagram of the LED system is attached as Appendix B. The diagram shows the electrical capability (rating) of the major equipment at each substation.

The diagram shows the pole mounted circuit reclosers noted above and the normally open manual tie switches between LED's 12.5 kV distribution circuits that allow it to temporarily transfer load to an alternate circuit or substation if necessary.

4.0 System Protection Practices

PLM has provided engineering support for the LED for the past 25 years, including short circuit analysis and recommended protective device settings for all circuit reclosers on the LED system. A coordination review of the affected equipment has been performed each time a major equipment component has been added or replaced or a large customer load added. In each case, specific device settings recommendations have been provided by PLM and implemented by LED. Careful attention is paid to ensuring that the devices will trip when necessary, but that upstream (source side) devices will not trip unnecessarily, which could result in a larger number of customers being affected.

The operating characteristics for every substation and sectionalizing circuit recloser have been engineered by plotting the phase and ground overcurrent time-current curves for the circuit recloser along with the adjacent upstream and downstream protective device. Circuit recloser settings have been specifically adapted to coordinate with branch or transformer fuses that exist at the larger customers, such as Imerys and the OMR, and to generally accommodate branch fuses in sizes up to 100 amperes.

4.1 Substations, Distribution Feeders and Mid-Feeder Reclosers

4.1.1 Route 103 Substation

Transformer high side protection at the Route 103 substation is accomplished using power fuses rated 200 amperes. The fuse size has been selected to adequately protect the transformer and coordinate with the (GMP) source side devices.

Distribution feeder protection for the Lake, Solitude and Jackson Gore feeders is accomplished using circuit reclosers with phase and ground fault detection. Automatic line reclosing (following detection of a fault) is utilized in order to avoid extended customer outage time due to a temporary fault.

There are no mid-feeder line reclosers on these circuits.

4.1.2 Commonwealth Substation

Transformer high side protection at the Commonwealth substation is accomplished using power fuses rated 200 amperes. The fuse size has been selected to adequately protect the transformer and coordinate with the (GMP) source side devices.

Distribution feeder protection for the Main (Street) and High (Street) feeders is accomplished using circuit reclosers with phase and ground fault detection. Automatic line reclosing (following detection of a fault) is utilized in order to avoid extended customer outage time due to a temporary fault.

Each feeder also incorporates a mid-feeder pole mounted circuit recloser that located on Okemo Ridge Rd. These reclosers protect customers served by the Main and High feeders in the Village of Ludlow from disturbances occurring further up on the mountain. These reclosers utilize single or three-phase tripping to minimize customer outages.

4.1.3 Smithville Substation

Transformer high side protection at the Smithville substation is accomplished using power fuses rated 200 amperes. The fuse size has been selected to adequately protect the transformer and coordinate with the source side devices.

Distribution feeder protection for the Smithville feeder is accomplished using a relayed circuit breaker with phase and ground fault detection. This is the only circuit breaker on the LED system, is of an older design that is approaching the end of its expected service life. The associated overvoltage relays are of an older electro-mechanical design that is being phased out by most utilities. Replacement of this equipment with a modern circuit recloser is recommended.

Beyond the riser on Route 103, the Smithville feeder bifurcates in several directions incorporates three mid-feeder pole mounted circuit reclosers. The Industrial Sites and Proctorsville reclosers isolate the respective portions of the feeder. The Imerys recloser isolates the customer-owned equipment at the Imerys manufacturing facility.

4.2 12.47 kV Feeder Branch Fusing

The ability to automatically detect faults and disconnect faulted branch lines is an important part of distribution system overcurrent protection. Fault detection devices located on the 12.5 kV distribution system include sectionalizing (mid-feeder) circuit reclosers with phase and ground current sensing as well as stepped size traditional branch fusing. A specific family of fuses with similar operating characteristics is used to ensure predictable branch fuse operation.

In overhead areas, branch fusing is accomplished using pole mounted fuse cutouts. Branch fusing is typically installed at any junction or tap for any overhead line of two spans or more. Branch fusing may be located in padmounted switchgear in underground areas.

Fuse links that are sized to 1) carry the necessary load and 2) coordinate with the adjacent upstream and downstream protective device. To ensure that a proper replacement is used and to aid with evaluating coordination, the actual fuse size is noted 5 ft. above the base of the pole supporting the fuse cutout. As an aid to service restoration, branch fuse locations are shown on LED’s system maps.

A general review of the LED feeder maps was done in order to confirm that branch fusing was being appropriately applied.

5.0 Historical System Peak Demand

5.1 Total System Demand

Due to the OMR and related activity, peak MW demand on the LED system occurs during the winter months. The LED’s 2019 Integrated Resource Plan (IRP) indicates that the LED experienced a new all-time peak MW demand of 13.058 MW during winter of 2018 and that the previous all-time peak MW demand of 12.871 MW occurred during winter of 2006. This indicates that winter peak demand on the LED system has increased only slightly over this 12 year period. The IRP also indicates that summer demand during the corresponding period increased from 7.048 MW to 8.352 MW.

5.2 GMP 15-Minute Demand Data

Each of the LED’s three substations is a metered delivery point for power to the system. MW and MVAR load data (15-minute interval) from January 1, 2017 to present for each of the LED’s three substations was obtained from GMP (the LED’s transmission supplier and metering agent). GMP also provided 15-minute interval load data for the two metering points where its native load is supplied via a LED substation. The GMP metering is located downstream of the substation metering, meaning that the GMP load must be subtracted from the substation load in order to determine the native LED load (GMP load values are entered as negative values in the table below).

5.3 Coincident System Peak Demand

An hour by hour analysis of the data furnished by GMP results in a coincident system peak demand of 13.413 MW that occurred on January 2, 2019 at 10:15 AM. This peak demand was higher than in past years and likely driven by the interconnection of new equipment at Imerys. The 15-minute interval demand data for this date and time, broken down by meter location, is shown in the table below.

Table 5-3
System Coincident Peak Demand by Metering Location

Substation	MW	MVAR	Power Factor
Commonwealth	6.837	0.861	.992
Route 103	3.192	0.168	.999
Smithville	4.290	0.782	.984
GMP Deroo Ln. (1)	-0.828	-0.123	.989
GMP Southface (2)	-0.078	-0.006	.997
LED Total	**13.413**	**1.682**	**0.992**

1. GMP load that is supplied via LED’s Smithville substation is subtracted from the above in order to determine the LED system internal demand.

2. GMP load that is supplied via LED’s Commonwealth substation is subtracted from the above in order to determine the LED system internal demand.

5.4 Individual Substation Peak Demand (Non-Coincident)

As might be expected, each of the LED’s individual substations experienced a peak demand that was not coincident with the overall system peak. As noted above, for two of the three substations, the substation peak demand also includes some GMP load. The peak demand on each individual substation, as found in the GMP 15-minute demand metering data, is shown in the table below.

Table 5-4
Individual Substation Peak Demand

Substation	MW	MVAR	Power Factor	Date/Time
Commonwealth	7.940	0.505	.998	1/12/19 5:45 PM
Route 103	4.242	0.246	.998	12/29/18 9:30 PM
Smithville	5.262	1,149	.981	1/18/19 6:30 PM

When determining the above, the simultaneous demand occurring at the other two substations was checked in order to ensure that the individual substation peak demand value shown was not the result of a temporary load transfer.

5.5 Okemo Mountain Resort Interruptible Snowmaking Load

Snowmaking at the OMR may be operated as desired as long as the overall LED system demand does not exceed the level specified in the snowmaking contract. The overall demand on the LED system has recently increased due to the addition of large electrical equipment at Imerys. To accommodate this change, the snowmaking demand limit was increased to 13.5 MW for the 2018-19 winter period. The LED system total demand is telemetered to the OMR at all times to facilitate this arrangement. The maximum LED total demand for the contract may be adjusted as needed and is calculated based on the previous year’s peak and the forecast of the next year’s system peak. The net result is that snowmaking load at the OMR should never be the cause of LED exceeding its forecasted peak demand.

6.0 System Peak Demand Load Forecast

6.1 Twenty-Year Peak Demand Load Forecast

The LED’s (IRP) that was recently prepared by the Vermont Public Power Supply Authority (VPPSA) includes a twenty-year peak demand load forecast. The comprehensive approach and methods that were utilized are fully documented therein. Increased use of electric vehicles, net metering and combined cooling heat and power (CCHP) systems were accounted for when preparing the forecast.

Peak demand on the LED system is forecast to increase by an average of 0.4% per year of the twenty-year study period, resulting in a total increase of 8.3% over the present level. Peak demand occurs in winter and is typically associated with the increased activity of the holiday season.

Values from the VPPSA forecast for the normal case are shown in the table below.

Table 6-1
Ludlow Electric Department – Peak Demand Load Forecast (Normal Case)

Year	Demand (MW)
2019	13.43
2020	13.38
2021	13.45
2022	13.58
2023	13.62
2024	13.52
2025	13.51
2026	13.57
2027	13.65
2028	14.11
2029	13.90
2030	13.83
2031	13.81
2032	14.19
2033	14.10
2034	14.21
2035	14.34
2036	14.00
2037	14.27
2038	14.38
2039	14.55

7.0 System Model

7.1 Software and Approach to Modeling

The LED system was modeled using Aspen DistriView software. This program was selected in part because it is able to handle single phase branch circuits and unbalanced load conditions at all nodes.

PLM had previously developed a model of the LED system. Data in the model was reviewed, updated and significantly enhanced as part of this study. GIS based distribution system mapping data was provided by LED. Additional data was obtained (or reviewed) in the field by PLM.

The LED system has been modeled using approximately 1960 nodes, approximately 890 of which are load buses (individual transformers) on the distribution feeders. In addition to the transmission and substation components, the model now incorporates a node at each distribution feeder branch connection and each distribution transformer.

kVA ratings were obtained from the LED for all of the larger padmounted distribution transformers on the system. The specific nameplate kVA rating for the pole mounted distribution transformers and the smaller padmounted transformers is generally not indicated on the LED distribution system mapping and impractical to fully compile or field check. To establish a load distribution within the model, all of the smaller transformers were assumed to be uniformly loaded.

In order be able to model the individual phase load on the distribution feeders, the phase connections for all single phase transformers were verified by a field review.

7.2 12.5 kV Feeder Demand Load Levels

kW demand and power factor information for the large industrial and commercial accounts was obtained and accounted for in the model. kW and kVAR demand values for each remaining transformer location were calculated in proportion to connected distribution transformer kVA, on a feeder by feeder, phase by phase basis, until the sum of the loads in the model (plus line losses) was approximately equal to the demand load and power factor for the individual substations and the total system.

The GMP Deroo Ln. load is metered at the Smithville substation and supplied through a separate distribution line that is owned by GMP. The LED Smithville feeder demand is therefore equal to the total demand on the Smithville substation minus the GMP Deroo metering point load. The GMP Southface load is supplied by the Main St. feeder and metered on the 12.5 kV distribution feeder at the transition from the LED to the GMP system. The GMP southface load is subtracted from the Main St. feeder and the Commonwealth substation load in order to determine the LED native load.

7.3 12.5 kV Feeder Coincident Peak Demand

Individual internal feeder loads coincident with the overall LED system peak demand were calculated as indicated above and summarized as follows:

Table 7-3
Substation and Feeder Coincident Peak Demand Load

Component	MW	MVAR	Power Factor
High St. Feeder	3.57	-0.24	1.00
Main St. Feeder	3.31	0.77	1.00
Lake Feeder	0.98	0.32	.95
Jackson Gore Feeder	0.58	0.04	1.00
Solitude Feeder	1.65	-0.21	0.99
Smithville Feeder	3.44	0.64	0.98

7.4 12.5 kV Feeder Non-Coincident Feeder Peak Demand

Individual internal feeder loads coincident with the individual substation peak demand levels were calculated as indicated above and summarized as follows:

Table 7-4
Feeder Non-Coincident Peak Demand Load

Component	MW	MVAR	Power Factor
High St. Feeder	4.95	0.06	1.00
Main St. Feeder	3.32	0.45	0.99
Lake Feeder	1.88	0.53	0.96
Jackson Gore Feeder	1.05	0.09	1.0
Solitude Feeder	1.28	-0.4	0.95
Smithville Feeder	4.64	1.0	0.98

Where individual substation or feeder load levels were determined to be higher under peak individual substation loading conditions than during the coincident system peak, these loads were also modeled and used to evaluate system performance with respect to thermal loading, voltage regulation, power factor correction, etc.

7.5 2019 Load Levels

The computer model was used to analyze system performance at 2019 load levels. Appendix C of this report includes voltage profiles for the longer distribution feeders (Lake, High St., Main St. and Smithville).

Appendix D is a schematic of the node and branch map as generated by the LED system computer model.

7.6 2039 Load Levels

As noted earlier, the forecast provided by VPPSA projects a system demand of 14.55 MW in the year 2039. This represents an increase of approximately 8.3 percent over existing demand levels.

A 2039 base case model was developed by taking the 2019 base case model, implemented the recommendations contained herein, and growing the system demand load to the projected 2039 level. For purposes of this screening analysis, no other changes were assumed. No additional reactive support was assumed.

The results indicate that the system is able to support the projected load level with no issues. Primary voltage levels on the most remote portions of the system will decrease slightly as the load increases, but all voltages were found to be within the recommended voltage range.

8.0 Summary of Computer Modeling Results

8.1 Thermal Analysis

No overloaded substation components or distribution line conductors were found to exist.

8.2 Voltage Performance

The system model has identified one location on the system where low voltage conditions have potential to exist during times of peak demand.

8.2.1 Northern End of Lake Feeder

The northwestern area of the Lake feeder is residential in nature and supplied by a long single phase branch of the feeder running along Route 100 North that is connected to B phase. It is recommended that a 100 kVAR capacitor be installed on or in vicinity of P. 109 Route 100 North. This will increase the voltage on B phase at this point (and all points beyond) by approximately 0.8 percent.

The northeastern area of the Lake feeder is also residential in nature and supplied by a long single phase branch of the feeder running along East Lake Rd. and connected to A phase. Three 50 kVAR capacitors have previously been installed in this branch of the feeder and provide voltage support. The system model indicates that voltage conditions are acceptable in this area.

While the system model is useful to predict possible low voltage conditions, it is recommended that the actual voltage conditions be checked at the above locations during winter loading conditions, to verify that they are acceptable. In addition, these areas should be periodically monitored going forward.

9.0 System Efficiencies and Improvements

All Vermont electrical utilities are required to develop a least cost integrated plan for the provision of electrical service. One of the major goals is to improve transmission and distribution system efficiencies with respect to reducing system losses.

The LED system was reviewed for potential efficiency improvements. A summary of the results of this analysis is included as Appendix E of this report.

9.1 Economic Evaluation of Efficiency Improvements

The economic evaluation of loss savings used in this report is based on a comparison between the cumulative present worth of projected annual savings, in dollars, and the net present value of life cycle societal costs associated with the investment. Where relevant, the crossover or "break even" year is indicated as an aid in prioritizing viable loss savings projects.

The annual cost calculations include both the fixed costs associated with new investment (i.e., interest, depreciation, insurance, etc.) and the variable costs (system demand and energy power supply). Annual costs have been discounted using a present worth factor so as to recognize the time value of money and an appropriate inflation factor was used. All costs are stated in constant (2019) dollars.

9.1.1 Avoided Power Purchase Costs

Avoided power purchase costs are based on a report entitled "Avoided Energy Supply Components in New England: 2018 Report, Prepared for AESC 2018 Study Group, dated March 30, 2018, which was furnished to PLM and LED by VPPSA in support of this study.

Avoided demand costs represent the projected cost of capacity and transmission from ISO-New England. The capacity prices (and resulting avoided capacity costs) are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market. The capacity price forecast is based on experience in recent auctions as well as expected changes in demand, supply and market rules.

Avoided wholesale energy costs change over time and are dependent on system demand, available generating units (including renewable and distributed generation, transmission constraints, fuel prices and other factors. Costs have been trending downward due to replacement of higher-cost fossil units with renewable alternatives, import of power from outside New England and the construction/upgrade of transmission lines.

9.1.2 Additional Avoided Cost Factors

A five percent allowance for externalities is added to the avoided costs. In addition, a small allowance is added to the calculated system loss savings to account for non-system (upstream) losses.

9.1.3 Economic Parameters

Annual Carrying Charges:

	Period	20 years
	Cost of Capital	5.0%
	Depreciation	5.0%
	Taxes	0.5%
	Insurance	0.5%
	O&M	3.0% (for T&D plant investments)
Principal Payment		5.0% (20 level payments assumed)
Discount Rate		4.5%

9.2 System Efficiency Improvements Selected for Evaluation

What follows is a list of the potential system efficiency improvements that were evaluated. The types of improvements that were evaluated are consistent with the 2005 Vermont Electric Plan.

The value of the projected loss savings for all recommended system improvements was determined and noted, whether or not the project was fully justified by the reduced losses. Each new evaluation was based on a system that incorporated the prior recommendations. A spreadsheet summarizing the results of the loss savings analysis that was performed as part of this study is included as Appendix E.

9.2.1 Strategic Placement and Control of Reactive Power Devices

Properly applied reactive power devices (power factor correction) provide a source of reactive power (measured as kVAR) which can be located at or near the load. Improving the power factor in proximity to the load decreases the line current, which will in turn reduce system I^2R losses. Properly placed reactive power devices also provide voltage support (reduce line voltage drop) in an economical, low maintenance fashion. This in turn helps with implementation of conservation voltage reduction.

These devices, typically in the form of pole mounted capacitor banks, can be fixed (always on line) or switched to follow changes in system load level. A variety of switching options are available, separately or in combination, including manual, time clock, voltage control, current control, power factor control, temperature control, and remote control via SCADA or radio systems, if available.

As shown in Appendix A, the existing LED system incorporates 2400 kVAR of switched and 2100 kVAR of fixed capacitor banks. These are all pole-mounted, located on the distribution feeders. A review of the reactive power requirements and voltage performance at time of peak demand indicates that the LED system would benefit from the following additional capacitor installations:

Table 9-2-1
Additional Distribution System Capacitors

Feeder	Location	Size (kVAR)	Phase	Switching
Smithville	P. 12-2 East Hill Rd.	600	ABC	Current Controlled
Lake	P. 109 Route 100 North	100	B	Fixed

The addition of the above will increase the kVAR on the LED system from 4500 to 5200. This will maintain LED's high system power factor on all feeders, reduce system losses and improve voltage levels. With respect to the additional capacitor bank that is recommended for the Smithville feeder, the load current on East Hill Rd. is due almost entirely to the Imerys facility. The demand load pattern at Imerys can be irregular. It is recommended that the new 600 kVAR bank be switched based on line current, which will follow the load and ensure that the bank is online when needed. The system model indicates that the addition of these capacitors will result in 2.2 kW of loss reduction at time of system peak demand, with additional loss reduction occurring during times of maximum demand at Imerys. The estimated cost to install the recommended equipment is $6,000, $4,500 of which will be offset by loss savings at time of system coincident peak demand.

9.2.2 Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) was implemented on the LED system approximately 25 years ago, using the substation voltage regulator controls. CVR, combined with adequate reactive power compensation, has allowed LED to continue to utilize CVR and realize the associated loss savings.

Each feeder on the LED system has independent voltage regulation at the substation. There are no mid-feeder voltage regulators on the LED system. The existing substation voltage regulator settings were reviewed using the system model. Voltage performance was checked under peak demand and light demand load levels. The settings changes recommended below will provide improved overall voltage performance. LED will continue to benefit from the loss savings associated with CVR. The recommended settings going forward are summarized in table 9-2-2 below.

Table 9-2-2

Recommended LED Voltage Regulator Settings

Feeder	**Line Drop Compensation**		**Float**	**Bandwidth**
	R	**X**	**(Volts)**	**(Volts)**
Lake	4.5*	4.4*	120.5*	2.5
Solitude	1.9*	1.9*	120	2.5
Jackson Gore	1.1*	1.2*	120*	2.5
High St.	3.4*	3.5*	120*	2.5
Main St.	3.1*	3.5*	120*	2.5
Smithville	1.2*	1.4*	120	2.5*

* Indicates a revised setting

General Comments on Voltage Regulation

The primary voltage level on a regulated distribution feeder should normally be between 126 and 118 volts, when referenced to the secondary, per ANSI standard C84.1-1982. This allows for an additional four volts drop through the distribution transformer and the secondary or service drop while still maintaining adequate voltage at the customer main switch.

As the load increases on a distribution feeder, a voltage drop through the primary conductor will cause customers at the end of the circuit to experience lower voltage levels than customers at or near the source. Proper voltage regulator settings combined with proper application of distribution line capacitors will help to mitigate this effect, however, it is not feasible to maintain a perfectly flat voltage profile along the entire length of the circuit under all loading conditions. Voltage regulator controls incorporate a bandwidth of acceptable voltage variation before a tap change is called for in order to reduce the number of tap changer operations and the associated equipment maintenance requirements. This bandwidth is typically two to three volts. Voltages within the bandwidth must be accounted for when performing voltage analysis.

9.2.3 Distribution Circuit Reconfiguration

Distribution circuit reconfiguration consists of arranging the primary distribution system so as to obtain the maximum benefit from the existing substation equipment, line conductors and other facilities. The existing LED circuit arrangement was reviewed for possible alternate circuit arrangements (relocate normally open point between circuits) which could result in reduced overall system losses in a cost effective manner. The system was found to be appropriately configured. No load transfers between distribution circuits are recommended.

9.2.4 LED Substation Automation

The LED automatically provides system demand level information to the OMR in order to facilitate the snowmaking contract.

Additional automation of LED’s substations would require that LED implement what is typically known as a SCADA (Supervisory Control and Data Acquisition) system. Because the system is compact and has been reliable, the incremental benefit does not justify the cost.

9.2.5 Reconductoring

The standard line conductors used on the LED system are shown in table 9-2-5.

Table 9-2-5

LED Standard Line Conductors

Loading	Overhead/Underground	Conductor Type
Main Line	Overhead	4/0 AWG AL Spacer Cable 4/0 AWG ACSR on Crossarms
Branch Line	Overhead	1/0 AWG ACSR on Crossarms
Main Line	Underground	500 kcmil CU or AL Cable
Branch Line	Underground	4/0 or 1/0 AWG AL Cable

The LED has standardized on the above in order to simplify requirements for stocking of hardware and accessories.

The LED's distribution feeders are lightly to moderately loaded. The most heavily loaded section of 4/0 AWG main line conductor is the 1700 ft. ft. section of spacer cable between the Commonwealth substation and Gill Terrace. Replacement of this conductor with 477 kcmil (the largest practical alternative) would result in a loss savings of 7.2 kW at time of system peak demand. The value of these loss savings is not sufficient to justify replacement of the conductor, which is estimated to be $35,000. It follows that replacement of any 4/0 AWG main line conductor that is more lightly loaded would also not be cost justified.

The LED notes that when the load at Imerys increased significantly approximately 3 years ago, the 4/0 ACSR Smithville feeder mainline from the substation to Route 103, a distance of approximately 3400 ft., was replaced with a 500 kcmil CU underground cable. The system model indicates that this upgrade has resulted in 15.7 kW of loss reduction at time of system peak demand.

9.2.6 Transformer Replacement

Table 9-2-6 lists the existing substation transformers on the LED system.

Table 9-2-6

LED Substation Transformers

Substation	**Voltage**	**MVA**	**Manufactured**
Route 103	43.8 to 12.47 kV	10/12.5/14	1987
Commonwealth	43.8 to 12.47 kV	9/12/15	9/1999
Smithville	43.8 to 12.47 kV	11/14	10/2003

LED's substation transformers are of modern design, are moderately loaded, and not at the end of their nominal 40-year service lives. Replacement cannot be justified solely based on losses. When it became ultimately becomes necessary to replace the transformer at the Route 103 substation, the evaluation of manufacturer's quotes should incorporate the net present value of load and core losses.

It is not generally economical to replace existing distribution transformers on a one-for-one basis with lower loss units. Utilities do purchase some additional distribution transformers on an ongoing basis for new customer loads and maintenance, and long term operating costs are important. It should be noted that, in 2009, the Department of Energy significantly increased its efficiency requirements for new distribution transformers. While this did add significantly to the cost of the transformers, it does ensure that all utilities conform to the new higher standards.

9.2.7 Increased Distribution System Voltage Levels

LED serves its entire load via regulated four wire 12.47 kV distribution circuits. Large customer loads are located in reasonable proximity to the existing substations.

LED's substations are supplied by a three wire 46 kV transmission system.

<u>Conversion to 34.5 kV Distribution</u>

The study examined the options for conversion of the distribution system to 34.5 kV operation. Conversion was found to be uneconomical for the following reasons:

- The transmission system operates at 46 kV. Substation transformers and related equipment would still be required.
- The distribution feeders are constructed for 12.47 kV operation and no distribution system equipment is currently in place to facilitate conversion to 34.5 kV.
- The distribution feeders are moderately loaded.
- The distribution and substation plant is well maintained and not in need of reconstruction, so there is no offsetting or lost opportunity cost that could be assumed.

A formal cost estimate for conversion of the system to 34.5 kV operation was not done. Based on experience with similar prior analyses, it can be safely stated that this expenditure would not be justified by loss savings within the twenty (20) year study period.

9.2.8 Distribution Transformer Load Management Program

It is beyond the intent or scope of this study to consider evaluation or implementation of a distribution transformer load management program

(DTLM). A program of this type would use customer kWh billing records in order to estimate transformer loading. A list of the most heavily loaded transformers could then be produced, allowing for further investigation by LED. It is unlikely that a DTLM program would be cost effective overall, given the relatively small number of transformers that could be expected to be heavily loaded.

9.3 Additional System Efficiency Improvements

The following other potential system efficiency improvements were also evaluated as part of this study.

The dollar value of the loss savings and implementation costs associated with the recommendations contained in this Section are also shown in the Summary of System Efficiency Improvements, which is attached as Appendix E.

9.3.1 Phase Balancing Loads on Circuits

Each of the LED distribution feeders was checked for load balance between phases. The load balance between phases is not static due to ongoing load fluctuation. Reasonably balanced phase loading at time of peak demand will reduce losses and improve end of line voltage levels.

The Lake feeder includes two large areas that are served via single-phase distribution. The East Lake Rd. area is supplied by A Phase. The Plymouth area (Route 100 North) is supplied by B Phase. Because of this, C phase is more lightly loaded. The feeder phase balance is improved if the single phase area along Route 103 North that is presently supplied by A Phase is transferred to C Phase. The system model indicates that this transfer provides 0.1 kW of loss reduction at time of system peak demand. The O&M related cost to perform this transfer is estimated to be $250.

The Main St. feeder was found to be in need of phase load balancing when a capacity review of the feeder was done in 2018. It was recommended that Line #5, the single phase tap on Commonwealth Ave. that extends northward from the substation, be transferred from C phase to A phase. This change has been incorporated into the system model and the analysis contained herein. The system model indicates that this improved load balance has resulted in 1.9 kW of loss reduction at time of system peak demand.

9.3.2 Expanded Three Phase Coverage

The extent of three phase coverage on a system is to a large degree driven by customer requests for three phase service. Three phase line may also be installed by the utility in order to create switching ties between circuits, and increased three phase coverage helps to minimize voltage drop on long circuits due to neutral current cancellation. Three phase coverage on the LED system is sufficient to meet the load and voltage requirements, and is generally present in the commercial and industrial areas of the system.

The longest single phase branch circuits on the LED system are on the Lake feeder. Route 100 north leading into Plymouth is supplied by a single phase tap connected to B Phase. The estimated maximum load level on this tap is 80 amperes. The load level on this tap that is coincident with the total LED system load (needed for loss savings analysis) is estimated to be 45 amperes. The first significant opportunity to divide the load between multiple phases occurs at the village of Plymouth, a distance of 7400 ft. from the end of the existing three phase line. Extending three phase coverage to this point and rebalancing the load would result in loss savings of 1.2 kW at time of coincident peak system demand. This level of loss savings is not sufficient to justify the estimated cost of $75,000 to perform the necessary line construction.

The East Lake Rd. area is supplied via a single phase tap connected to A phase. The estimated maximum load level on this tap is 60 amperes. Similar to the above, the loss savings that would be realized by extending three phase coverage is not sufficient to justify the cost of the necessary line construction.

9.3.3 Installation of Additional Switching Capability

The LED system incorporates numerous switching points in order to be able to rearrange load in order to restore service or remove a substation for maintenance. No additional switching points are recommended.

In some cases, switching on the distribution system is performed using single phase devices. For ease of operation and safety considerations (switches can be operated at ground level and at a distance), it is recommended that gang operated three phase switches be considered when replacing these single-phase devices.

9.3.4 Addition of Circuits

The Smithville feeder serves LED and GMP distribution customer load. Approximately two years ago, and in conjunction with increasing the feeder capacity, LED and GMP reworked the 12.47 kV distribution circuit getaways (portion of the circuit exiting the substation) to provide increased reliability and operating flexibility. Although supplied by the same substation equipment, separately owned and maintained 12.47 kV distribution circuits now begin at the substation for each utility.

No additional opportunities to add distribution circuits were identified as part of this study.

9.3.5 Installation of Distribution System Automation Equipment

The concept of economic dispatch is generally associated with system generation facilities. This principal could also be applied to a distribution system that supported several major load centers which peaked at different times.

It is assumed that the system is normally arranged in such a fashion that system losses on peak are at the lowest possible level. In this case, only the energy component of the loss savings should be used when calculating possible loss savings attributable to distribution system automation.

No cost effective options for real time switching of distribution loads in order to increase system efficiencies were identified.

9.3.6 Utilization of Load Management Systems to Improve Distribution Efficiency

LED has an existing arrangement with its largest customer, the Okemo Mountain Resort, by which snowmaking is reduced or curtailed during times of LED system peak electrical demand. The system load is monitored directly by the ski area.

LED has several other large customers, the biggest being Imerys. It is beyond the scope of this study to evaluate whether load management alternatives at any of LED's other large customers would reduce LED system demand. Large customers are generally conscious of their demand and already have an economic incentive to levelize or reduce demand. It is likely that any loss savings that might be realized would not be sufficient to justify the cost of implementation, which could require communications equipment, a special rate, etc.

9.3.7 Addition/Expansion of Substations

The present number of substations and feeder positions is sufficient to serve the system load. The three distribution substation locations are sufficiently close to the load centers and are able to serve the system load now and throughout the study period. The substations each have a single transformer but the ability to transfer load via field switching allows for continuity of service under most loading conditions in the event that a substation is unavailable. The development of another substation site is not needed or recommended.

10.0 Recommendations for Immediate Implementation

Items for immediate implementation are summarized below. Supporting details are presented in the preceding sections of this study.

10.1 Additional Power Factor Correction Capacitors

As noted in Section 9.2.1 and in Table 9-2-1, the following additional power factor correction capacitors are recommended:

Feeder	Location	Size (kVAR)	Phase	Switching
Smithville	P. 12-2 East Hill Rd.	600	ABC	Current Controlled
Lake	P. 109 Route 100 North	100	B	Fixed

The estimated cost to purchase and install the above is $6,000.

10.2 Updated Voltage Regulator Settings

As noted in Section 9.2.2 and in Table 9-2-2, the following updated settings are recommended for the LED's substation voltage regulators:

Feeder	Line Drop Compensation		Float	Bandwidth
	R	X	(Volts)	(Volts)
Lake	4.5*	4.4*	120.5*	2.5
Solitude	1.9*	1.9*	120	2.5
Jackson Gore	1.1*	1.2*	120*	2.5
High St.	3.4*	3.5*	120*	2.5
Main St.	3.1*	3.5*	120*	2.5
Smithville	1.2*	1.4*	120	2.5*

*Change to existing setting.

There is no significant cost associated with implementation of these settings changes.

10.3 Feeder Phase Load Balancing

As noted in Section 9.3.1, the phase balance on the Lake feeder can be improved by transferring the single phase tap that extends along Route 103 to the north of the intersection with Route 100 North from A phase to C phase. There is no significant cost associated with this transfer.

10.4 Replacement of Smithville 12.5 kV Circuit Breaker

As noted in Section 4.1.3, the Smithville 12.5 kV feeder incorporates the only circuit breaker on the LED system. This circuit breaker is of an older design that is reaching the end of its service life. The associated protective relays are of an older electro-mechanical design. Its replacement with a modern circuit recloser is recommended. The estimated cost to purchase and install the above is $50,000.

11.0 Long Range Plan - Future Considerations

The following general long range strategy is suggested for the LED system:

1. On an annual basis, request from GMP and conduct a review of the interval load data for each LED substation.
2. Continue to monitor substation loads and distribution feeder load levels. For any new large customer loads, perform an interconnection review in order to identify any necessary system upgrades.
3. Monitor customer utilization voltage levels, paying particular attention to the long single phase branch lines at the tail end of the Lake feeder. These areas have been identified as the most likely locations where voltage concerns could exist.
4. Monitor the system power factor and, as the load grows, install additional power factor correction capacitors as needed to correct the power factor back to the desired value of 0.99 or better at time of system peak demand.
5. Monitor the internal condition (via oil sampling, etc.) and plan for the replacement (due to end of expected service life) of the main power transformer and two sets of voltage regulators at the Route 103 substation.

Appendices

Appendix A – LED Distribution System Capacitors

Appendix B – LED System One Line Diagram

Appendix C – Selected Feeder Voltage Profiles

Appendix D – System Node and Branch Map Schematic

Appendix E - Loss Savings Summary

Revision History

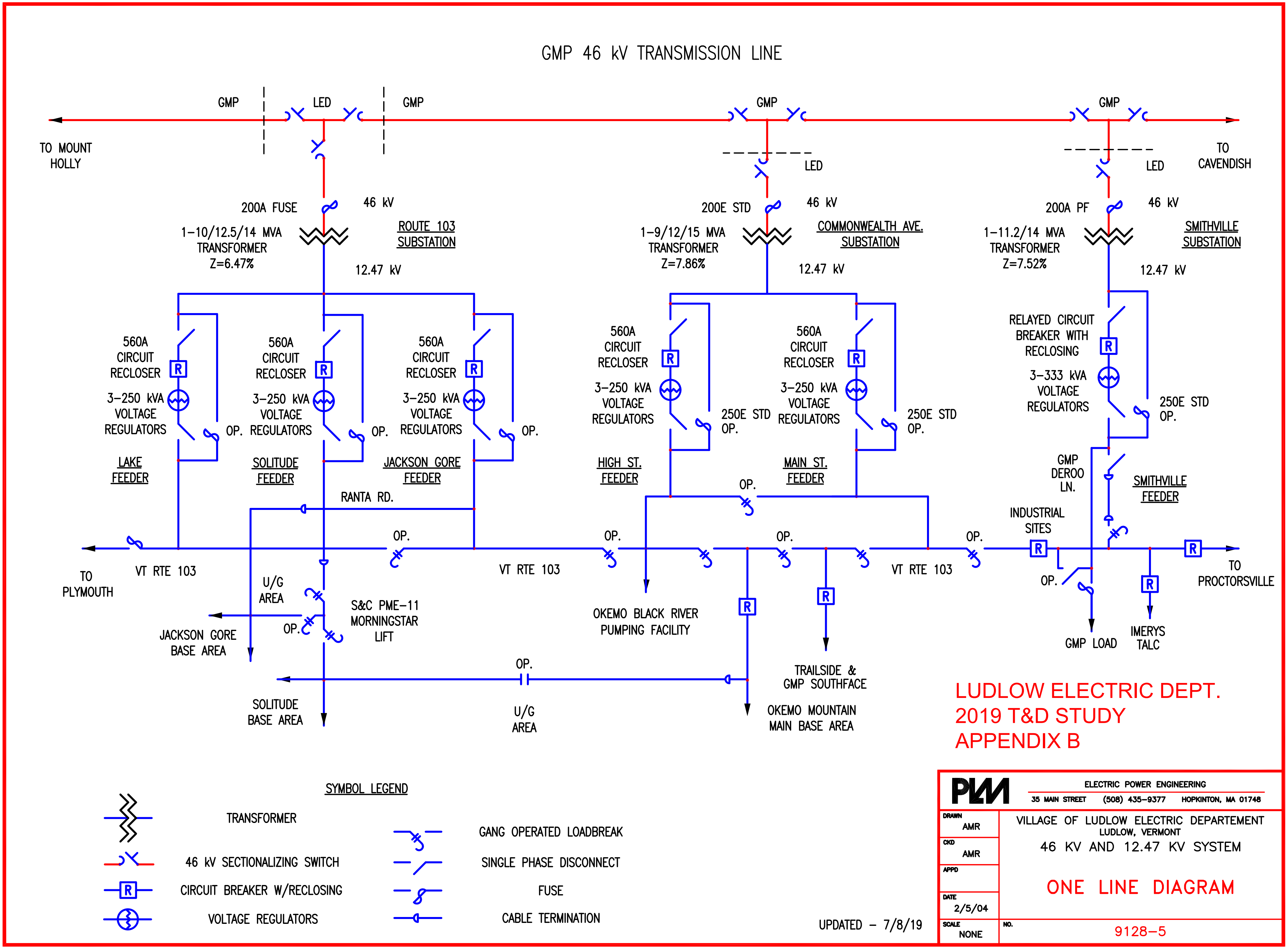
Date	By	Rev. No.	Description
11/12/19	AMR	0	Draft for Client Review

Capacitors on Ludlow Electric System
July-19

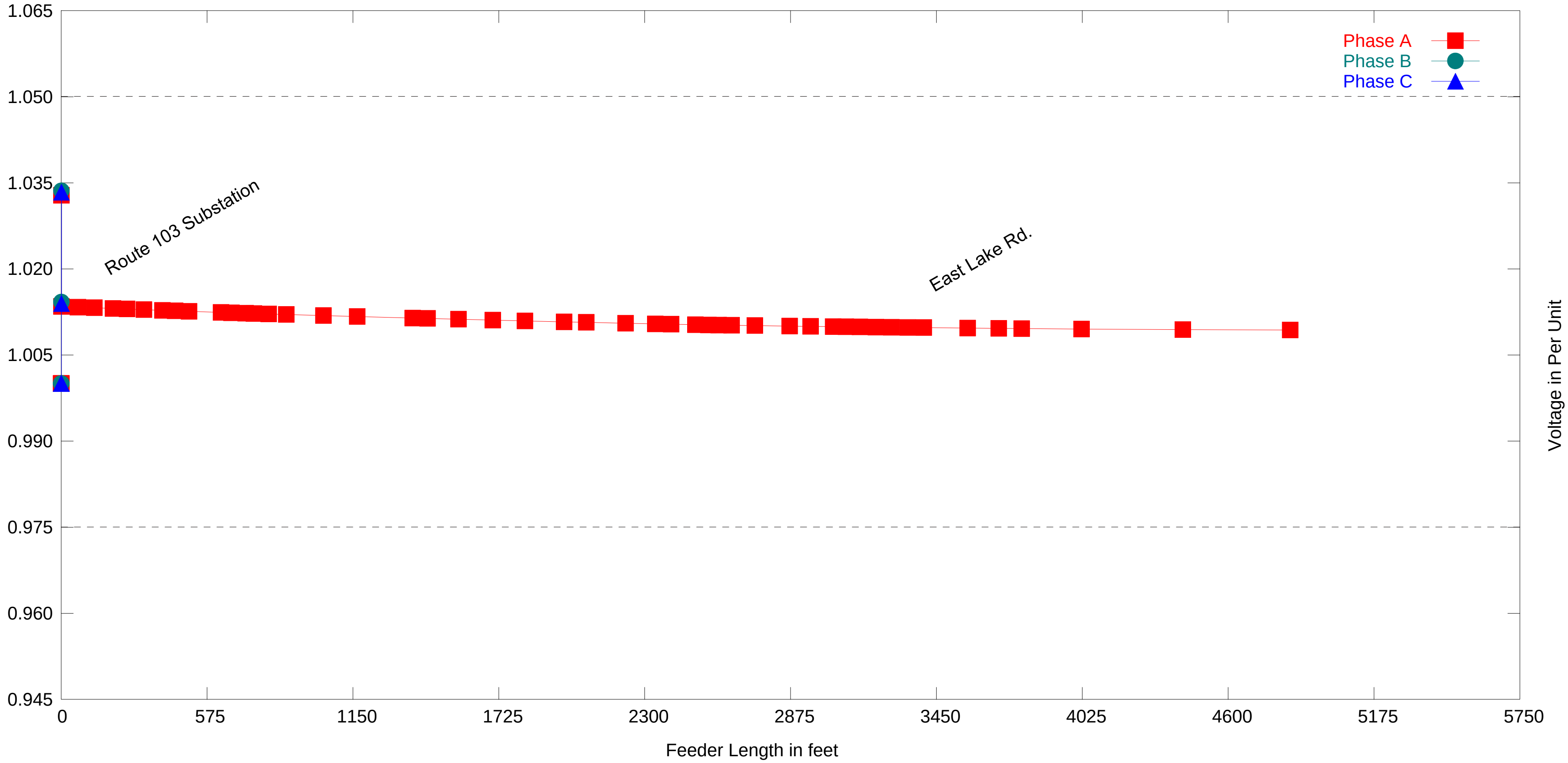
Location	Line # Pole #	KVAR	Substation	Distance From Substation	Phase	Type	Control
Dug Road	L.6 P.28	900 (3-300)	Commonwealth	5,280	3 Phase	Switched	powerflex
Andover/main st.	L.85 P.2	300 (3-100)	Commonwealth	4,224	3 Phase	Fixed	
Okemo Ridge rd.	L.22 P.12	300 (3-100)	Commonwealth	12,160	3 Phase	Fixed	
Okemo Ridge rd.	L.22 P.5	300 (3-100)	Commonwealth	10,560	3 Phase	Switched	powerflex
Okemo Access Rd.	L.2 P.53	300 (3-100)	Commonwealth	9,500	3 Phase	Switched	powerflex
Ghia Farm Rd.	L.2 P.64	150 (3-50)	Commonwealth	11,850	3 Phase	Fixed	
East Main St.	L.7 P.18	300 (3-100)	Smithville	7,920	3 Phase	Fixed	
Rt.103 South	L.9 P.18	300 (3-100)	Smithville	6,836	3 Phase	Fixed	
East Lake Road	L.32 P.44	150 (3-50)	Rt. 103	13,728	Single Phase	Fixed	
103 /Okemo Access Rd.	L.2 P35	300 (3-100)	Commonwealth	5,280	3 Phase	Fixed	
Ranta Rd.	L.1 P.5x	900 (3-300)	Rt. 103	500	3 Phase	Switched	powerflex
Ranta Rd.	L.1 P.10	300 (3-100)	Rt. 103	1,000	3 Phase	Fixed	

East Lake Rd was **on** during winter peak

Total Switched kVAR	2400
Total Fixed kVAR	2100
Total kVAR	4500

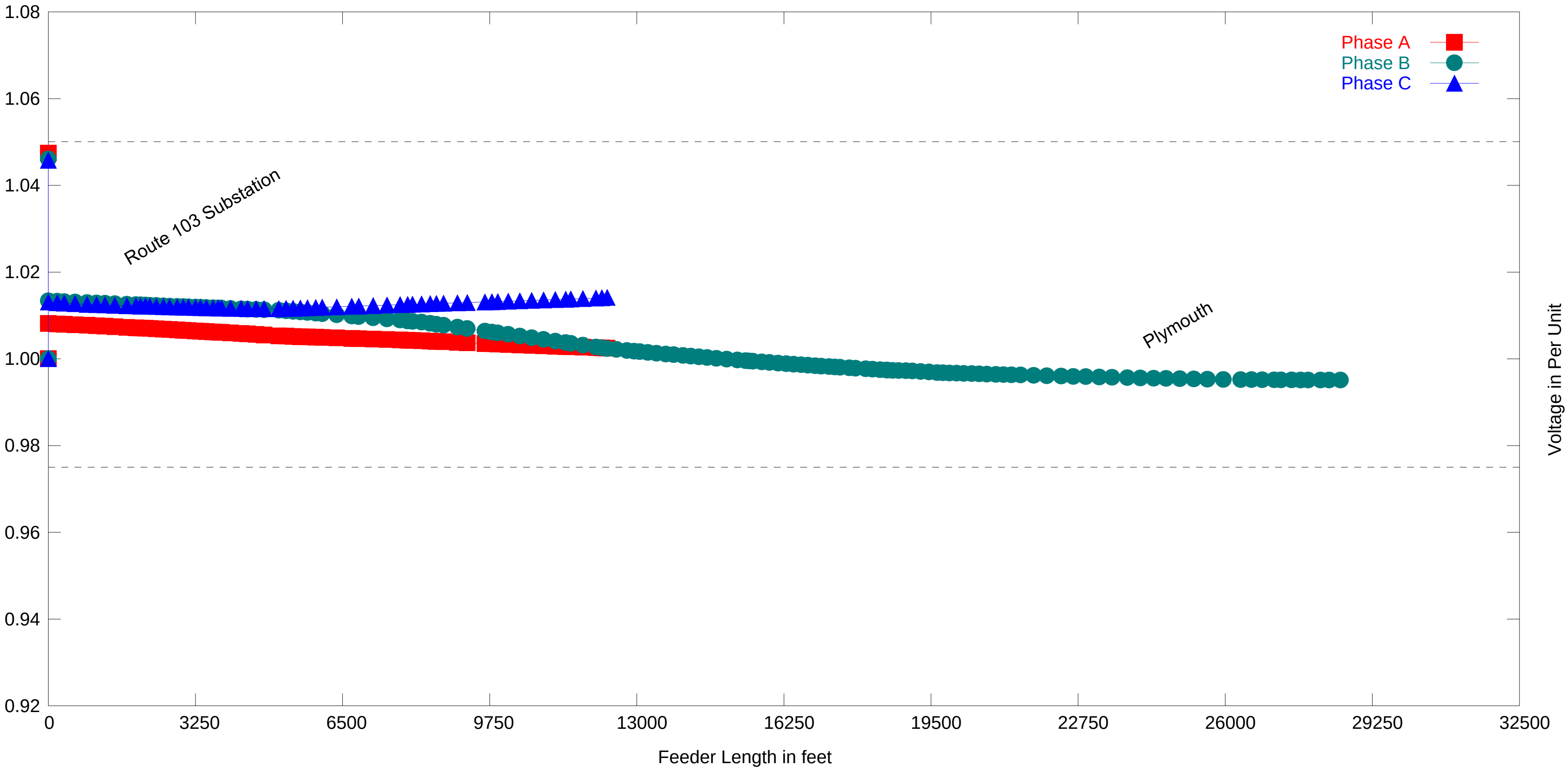

GMP 46 kV TRANSMISSION LINE
GMP
LED
GMP
GMP
GMP
TO MOUNT HOLLY
LED
LED
TO CAVENDISH
200A FUSE
46 kV
1-10/12.5/14 MVA TRANSFORMER Z=6.47%
ROUTE 103 SUBSTATION
12.47 kV
200E STD
46 kV
1-9/12/15 MVA TRANSFORMER Z=7.86%
COMMONWEALTH AVE. SUBSTATION
12.47 kV
200A PF
46 kV
1-11.2/14 MVA TRANSFORMER Z=7.52%
SMITHVILLE SUBSTATION
12.47 kV
560A CIRCUIT RECLOSER
3-250 kVA VOLTAGE REGULATORS
OP.
LAKE FEEDER
SOLITUDE FEEDER
JACKSON GORE FEEDER
RANTA RD.
560A CIRCUIT RECLOSER
3-250 kVA VOLTAGE REGULATORS
250E STD OP.
HIGH ST. FEEDER
MAIN ST. FEEDER
RELAYED CIRCUIT BREAKER WITH RECLOSING
3-333 kVA VOLTAGE REGULATORS
250E STD OP.
GMP DEROO LN.
SMITHVILLE FEEDER
INDUSTRIAL SITES
TO PLYMOUTH
VT RTE 103
U/G AREA
S&C PME-11 MORNINGSTAR LIFT
JACKSON GORE BASE AREA
SOLITUDE BASE AREA
U/G AREA
OKEMO BLACK RIVER PUMPING FACILITY
TRAILSIDE & GMP SOUTHFACE
OKEMO MOUNTAIN MAIN BASE AREA
GMP LOAD
IMERYS TALC
TO PROCTORSVILLE
LUDLOW ELECTRIC DEPT.
2019 T&D STUDY
APPENDIX B
SYMBOL LEGEND
TRANSFORMER
46 kV SECTIONALIZING SWITCH
CIRCUIT BREAKER W/RECLOSING
VOLTAGE REGULATORS
GANG OPERATED LOADBREAK
SINGLE PHASE DISCONNECT
FUSE
CABLE TERMINATION
UPDATED - 7/8/19
PLM
ELECTRIC POWER ENGINEERING
35 MAIN STREET (508) 435-9377 HOPKINTON, MA 01748
DRAWN AMR
CKD AMR
APPD
DATE 2/5/04
SCALE NONE
VILLAGE OF LUDLOW ELECTRIC DEPARTEMENT
LUDLOW, VERMONT
46 KV AND 12.47 KV SYSTEM
ONE LINE DIAGRAM
NO. 9128-5

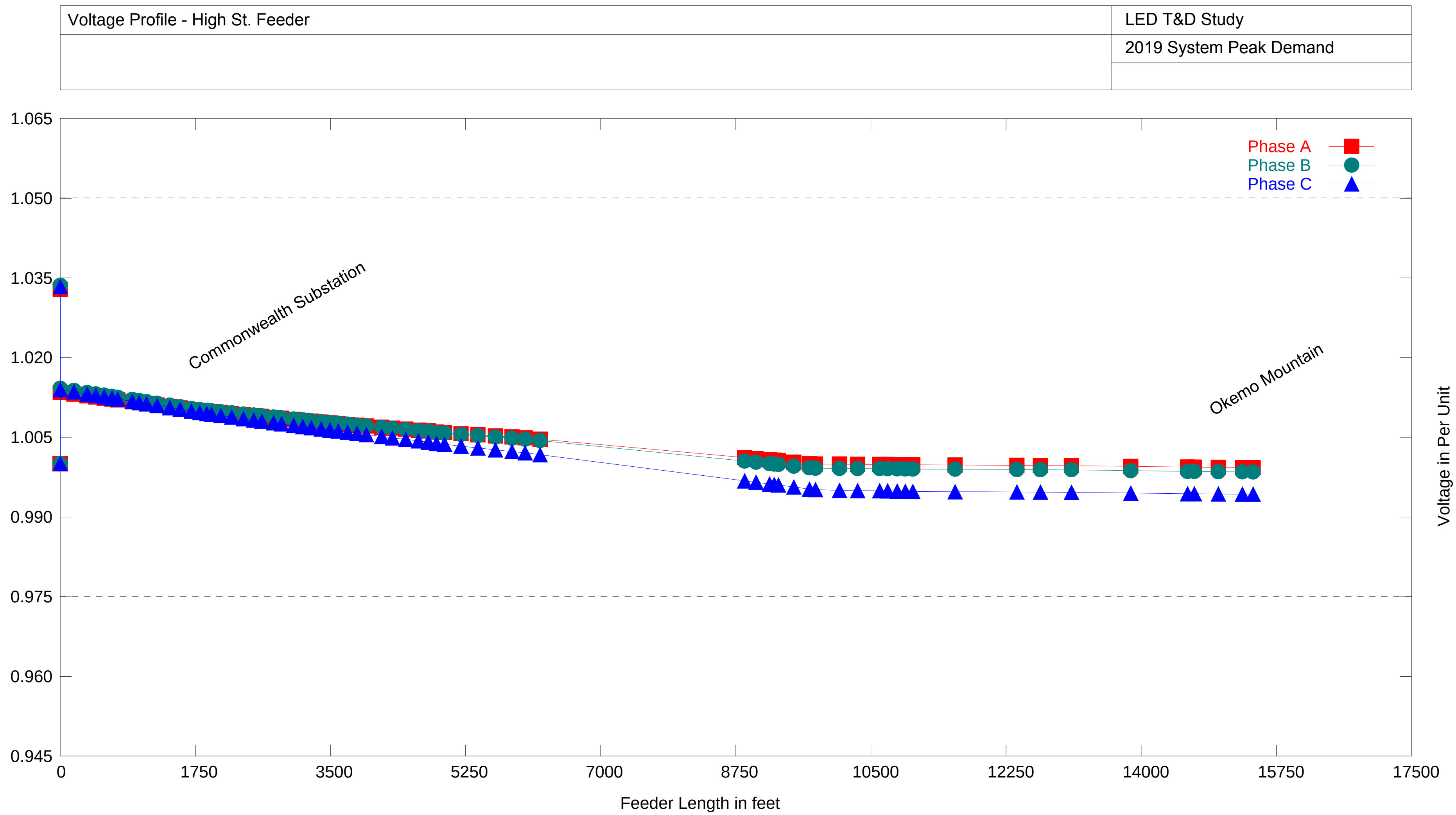
Voltage Profile - Lake Feeder A Phase	LED T&D Study
	2019 System Peak Demand



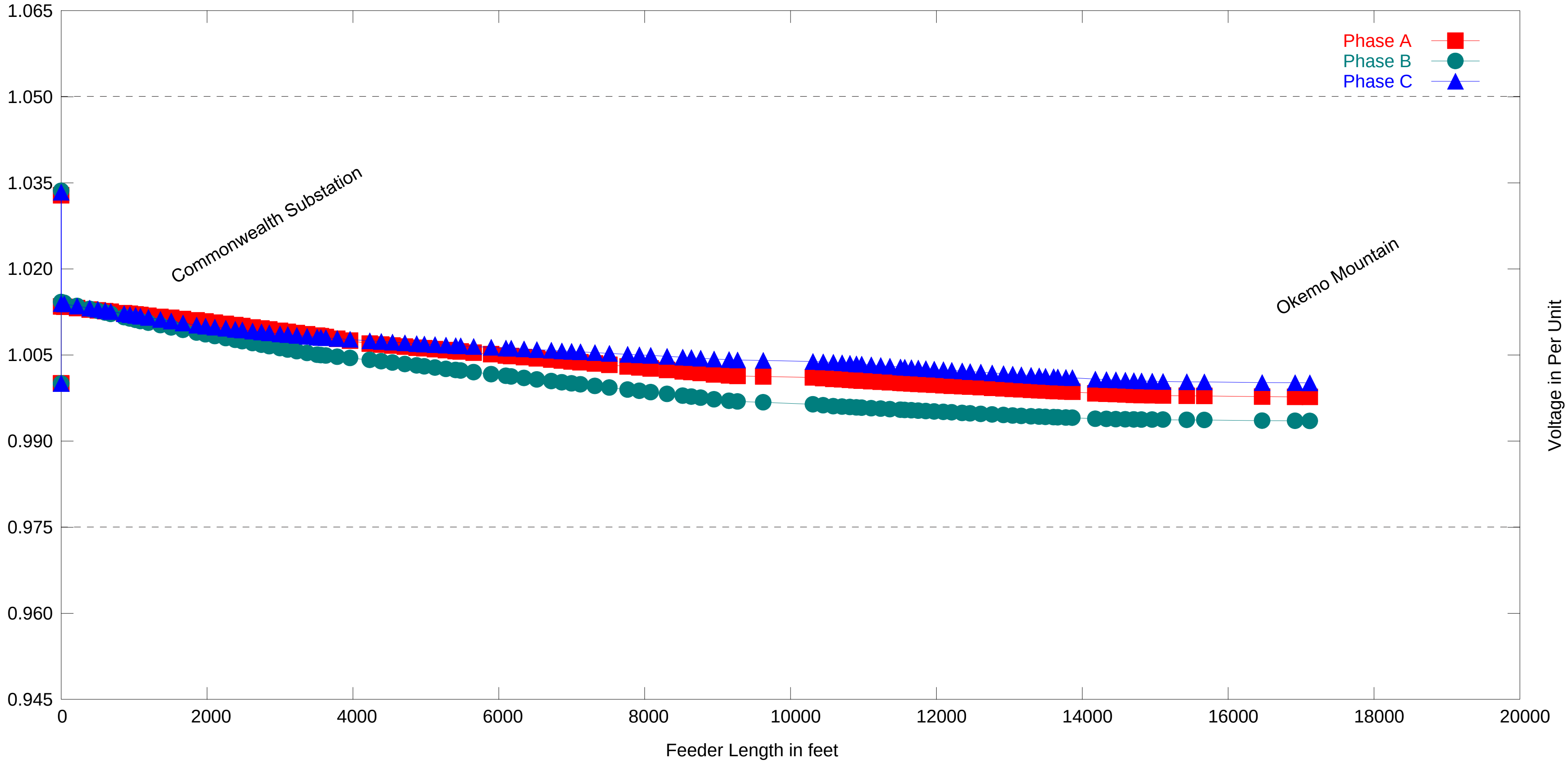
LUDLOW ELECTRIC DEPT.
2019 T&D STUDY
APPENDIX C

Voltage Profile - Lake Feeder B Phase	LED T&D Study
	2019 System Peak Demand

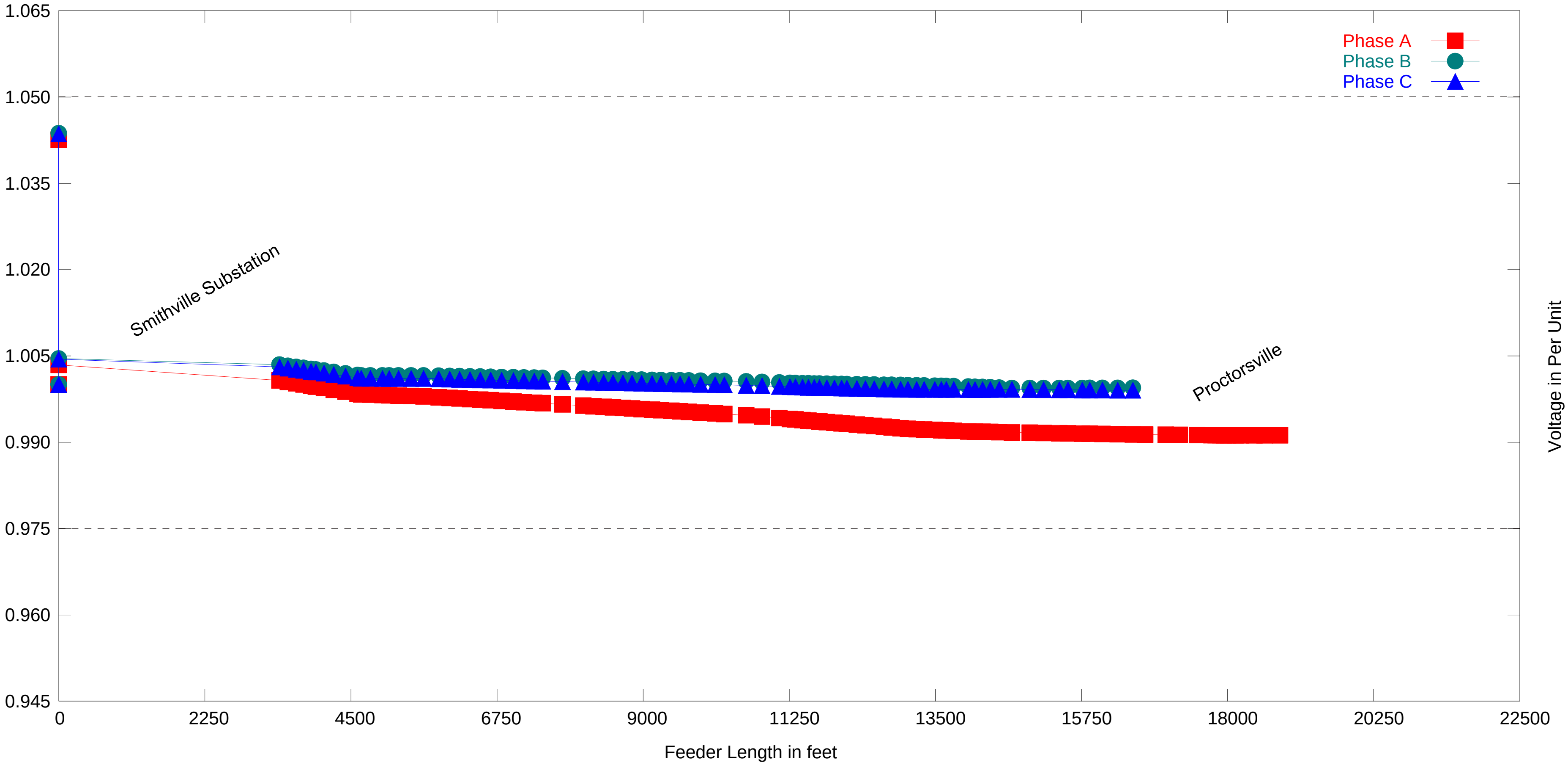


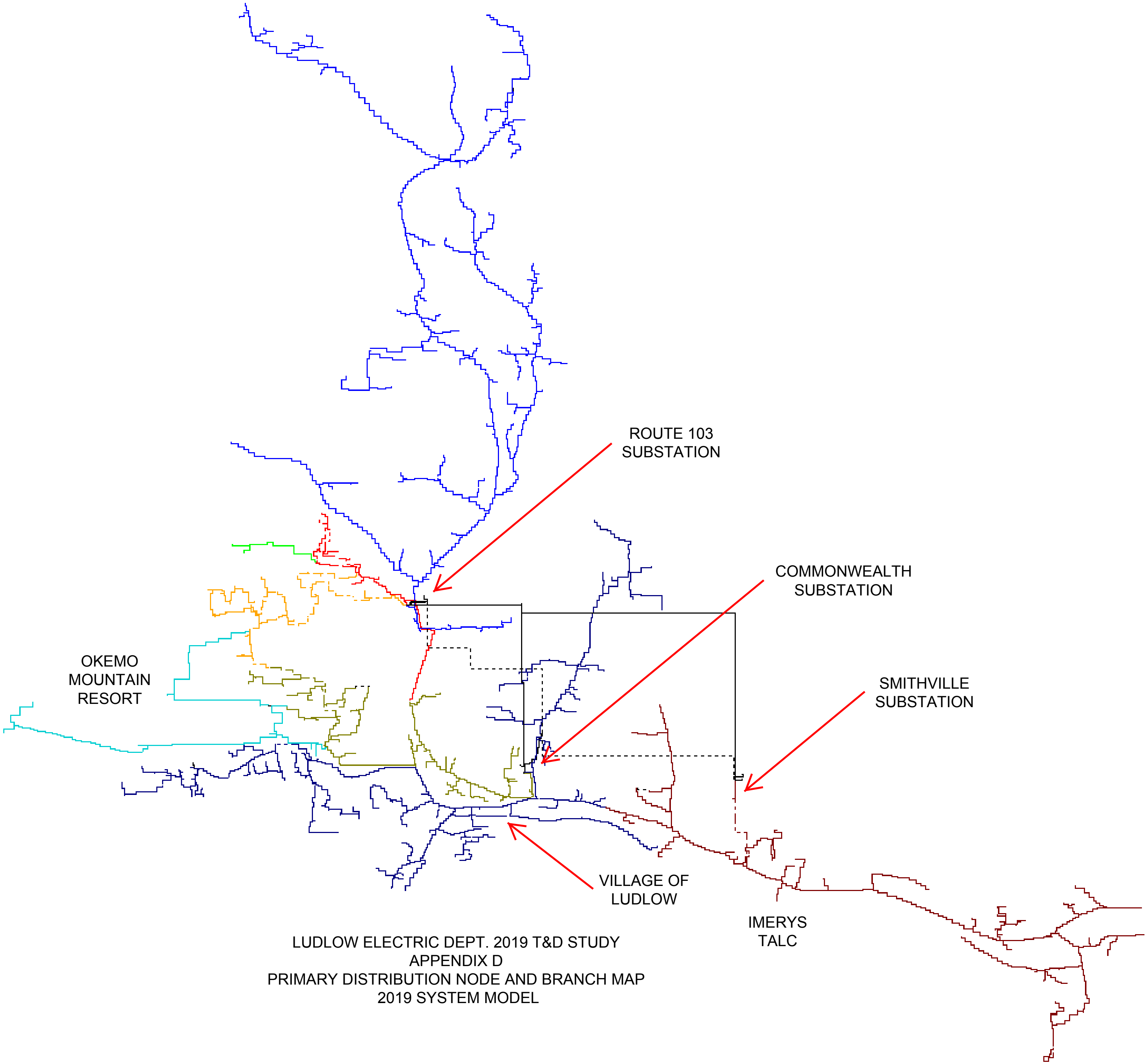

Voltage Profile - High St. Feeder
LED T&D Study
2019 System Peak Demand
Phase A
Phase B
Phase C
Commonwealth Substation
Okemo Mountain
1.065
1.050
1.035
1.020
1.005
0.990
0.975
0.960
0.945
0
1750
3500
5250
7000
8750
10500
12250
14000
15750
17500
Feeder Length in feet
Voltage in Per Unit

Voltage Profile - Main St. Feeder	LED T&D Study
	2019 System Peak Demand



Voltage Profile - Smithville Feeder	LED T&D Study
	2019 System Peak Demand





LUDLOW ELECTRIC DEPT. 2019 T&D STUDY
APPENDIX D
PRIMARY DISTRIBUTION NODE AND BRANCH MAP
2019 SYSTEM MODEL

Ludlow Electric Department - 2019 T&D Study
Appendix E - Summary of System Improvements and Associated Loss Savings
Initial losses based on system load and configuration at time of January 2, 2019 Coincident System Peak Demand

Item	Report Section Ref.	Construction Item and Description	LED System Losses Before (kW)	LED System Losses After (kW)	LED System Loss Savings (kW)	20 Year NPV of Loss Savings ($)	2020 Construction Cost Fully Justified by Loss Savings ($)	2020 Estimated Cost to Implement ($)	20 Year NPV of Cost to Implement ($)	20 Year NPV of Differential ($)	Recommended (Y/N)
1	9.2.5	Replace feeder mainline from Smithville Substation to Rte 103 with 500 kcmil CU underground cable	240.5	224.8	15.7	Note: This work was completed in 2016 to support load increase at Imerys Talc America on East Hill Rd. It is noted here to document the reduction in kW losses that was also realized.					
2	9.3.1	Transfer Commonwealth Ave. single phase tap from C phase to A phase	224.8	222.9	1.9	Note: This feeder load balancing step was recommended in 2018 to increase available capacity on the Main St. feeder to better accommodate load growth at the Southface development on Okemo Mountain. It is noted here to document the reduction in kW losses that was also realized.					
4	9.2.1	Install 600 kVAR switched capacitor on Smithville Feeder and 100 kVAR fixed capacitor on Lake Feeder	222.9	220.7	2.2	$ 7,080	$ 4,500	$ 6,000	$ 9,355	$ (2,275)	Yes (provides additional benefits during non-coincident feeder peak loading)
5	9.3.1	Transfer single phase branch on Route 103 north of Route 100 North from A phase to C phase	220.7	220.6	0.1	$ 322	$ 375	$ 250	$ 250	$ 72	Yes
6	9.3.2	Extend three phase coverage on Lake feeder on Route 100 North, from end of existing three phase to village of Plymouth, a distance of 7,400 ft.	220.6	219.4	1.2	$ 3,862	$ 2,500	$ 75,000	$ 116,937	$ (113,075)	No
7	9.2.5	Reconductor 4/0 AWG spacer cable mainline on the High St. feeder with 477 kcmil spacer cable, from Commonweath substation to Gill Ter., a distance of 1,700 ft.	220.6	213.4	7.2	$ 23,171	$ 15,000	$ 35,000	$ 54,571	$ (31,400)	No
8	2.3	Relocate three phase mainline that feeds Proctorsville and vicinity from right-of-way to along Route 103. Install 4/0 AWG spacer cable, a distance of approximately 6,400 ft.	220.6	219.8	0.8	Note: This line reconstruction/relocation project is being done due to aging facilities, to improve access and to relocate the line away from the bank of the Black River and a railroad corridor, all of which provide reliability benefits. It is noted here to document the reduction in kW losses that will also be realized.					

APPENDIX H: TIER III LIFE-CYCLE COST ANALYSIS

The Tier III Rule states that:

"4.410 (3) The Energy Transformation Project shall meet the need for its goods or services at the lowest present-value life-cycle cost, including environmental and economic costs. This evaluation shall include an analysis of alternatives that do not increase electric consumption. If a Retail Electricity Provider's Integrated Resource Plan includes an analysis of alternatives, the Provider's Tier III annual plan shall reference the analysis in the Integrated Resource Plan and shall include any significant changes. If a Provider's Integrated Resource Plan does not include an analysis of alternatives, the Provider's Tier III annual plan shall include the analysis."

Because ninety-five percent of the savings from LED's Tier III programs are from four measures, we summarize the life cycle costs for electric vehicles and heat pumps in Table 29. In terms of avoided costs, these ratios are based on the forecast of electricity, capacity and transmission prices that support the financial analysis section. The measure savings (lifetime kWh) are consistent with the averages in the Tier III Planning Tool for Program Year 2022, and the value of avoided emissions is consistent with the 2021 Avoided Energy Supply Cost (AESC) study. Finally, the retail rates are based on a forecast of LED's residential rate.

Table 1: Life-Cycle Cost-Benefit Ratios

Measure	Utility	Customer	Society
EV	0.8	0.4	0.5
PHEV	0.8	0.5	0.8
CCHP	1.0	1.1	1.3
WBHP	0.9	1.6	1.8

Heat pumps are the least-cost measure. The provide net benefits to both the customer, to society, and they break-even for the utility. Electric vehicles have much higher incremental costs as well as shorter measure lives. As a result, their cost-benefit ratios are less attractive. The Tier III Planning Tool does include some measures that do not increase electric consumption. These measures include the use of biodiesel, the use of wood pellets, telecommuting, bicycle commuting, using public transportation and installing smart thermostats. LED will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.