Village of Morrisville Water & Light Department

2023 Integrated Resource Plan

As filed with the Vermont Public Utility Commission

Vermont Public Power Supply Authority

EXECUTIVE SUMMARY

In this IRP Morrisville Water & Light Department (MWL) embraces a multipronged strategy to ready itself for a ten to twenty year transition to the energy provider that state policy and customers will expect and or demand for our future. This includes committing to 100% renewable energy by 2030, the adoption of a technology roadmap, the embracing of a strategy for a tri-level battery storage solution, embracing 100% beneficial electrification, consideration of how best to improve reliability to near 100% (as customers will expect in a beneficial electrification world), and committing to accomplish all of this in a manner that is more cost effective for its customers than simply operating the electric system of 2023 under static conditions for the coming decades. This commitment to keeping costs low and economic value high will result in MWL raising questions about how deeply state policy ought to tread into layering social programming on to electric bills. However, MWL believes strongly that it is simply imperative that rates and bills for total energy costs must make sense if the policy direction of the State of Vermont is to be embraced in the more rural parts of our state. It certainly is true, in the opinion of MWL, in our service territory.

While all these topics are important, this IRP first begins to explore in some detail the impacts of more rapid and intense electrification than has been experienced to date. Having worked with PLM Electric Power Engineering to complete a full Transmission and Distribution system planning study as of September of 2022, MWL is in possession of a comprehensive system assessment identifying current deficiencies, along with recommended near-term upgrades and a long-range plan for system improvements grounded in current load forecasts. This study provides a fresh baseline against which MWL can begin to contrast anticipated electrification driven load impacts and the associated distribution system improvements that will be required.

While the timing and intensity of electrification related load growth is uncertain, for analytical purposes in this IRP, MWL has chosen to develop what it believes to be an aggressive "Full Electrification" load forecast reflecting 200% saturation for electric vehicles and heat pumps (two EVs and two heat pumps at every premises) over the 20-year study period. The base, or reference, load forecast reflects the same electrification inputs and assumptions that were approved by the Vermont System Planning Committee during VELCO's 2021 Long-Range Transmission Plan (LRTP), which are less aggressive than the Full Electrification forecast.

MWL's choice to utilize an aggressive electrification forecast in this IRP is intended to provide context and a framework to highlight or illustrate certain "down-system" impacts or consequences should load growth occur as modeled. For instance, the "Full Electrification" case anticipates that MWL's winter peak and usage roughly doubles, assuming an ideal DERMS system, over the 20-year study period, raising a number of interesting questions. The most obvious question is how much and how quickly load will grow; that remains to be seen and as we develop better information over time, subsequent IRPs will reflect more detailed and comprehensive analysis.

Given the expectation that load may double, significant system investment can be expected. Morrisville has commissioned PLM to provide an analysis of further system investment that will be needed should load growth play out as modeled; the results of that study won't be available until early 2024 but preliminary, high-level estimates indicate that $15-$20 million of upgrades, in addition to planned upgrades reflected in this IRP's reference case, will become necessary. These estimated upgrades fall mainly in the substation and feeder area; it wouldn't be surprising to see much higher estimates in the final study results.

Other investment, embedded in both the reference and Full Electrification case, includes significant enhancement to customer, operations, and grid management software and technology, ranging from Customer Information/billing systems to AMI, GIS, DERMS, and Low Income Management initiatives. Other significant planned capital expenditures include over $20 million of hydro investment and routine vehicle replacement.

In addition, MWL anticipates as much as $40 million of new storage investment of various sizes, in multiple locations during the 2025-2035 period aimed at enhancing resilience and peak load management. Due to current uncertainty around the rate and locational aspects of electrification driven load growth, this issue is analyzed on a stand-alone, avoided cost basis, rather than attempting to model various sized installations as specific resources at as yet undetermined locations. MWL feels this is an important issue to flag now; as customers embrace electrification and become more "grid-dependent", the expectation of near-100% reliability will surely increase. Storage at various locations will play an important role in this resiliency effort, as well as in effectively managing peak loads. More detailed modeling will become possible in subsequent IRPs as better and more detailed information regarding load and optimal location of storage becomes known.

The commitment to a 100% renewable target by 2030 has significant implications for MWL's resource mix and procurement strategy. To meet this commitment MWL would need 80% of its supply to come from Tier I resources which translates to an additional 8,000 MWH's of wind or hydro resources over the current 2024 level. In addition, 20% of MWL's resource supply will need come from Tier II resources; an additional 3.5 MW of solar would be needed to fulfill and maintain Tier II requirements through the 2030s.

Needless to say, the level of anticipated distribution system investment, which ranges from $35 million in the reference case to $90 million in the full electrification case including storage, highlights financing as a potential issue. Current modeling indicates that by the early 2030's MWL's debt level may be in the 45% to 50% of total capital range; when $40 million of storage investment is incorporated, the debt level rises to the 60%-65% of total capital range. Should the level of electrification driven investment increase significantly beyond current estimates, or should it accelerate significantly, financing may become more constrained or expensive and additional rate pressure may be experienced. MWL does not currently anticipate a scenario where additional financing becomes impossible but that potential does bear watching; accordingly, the MWL trustees have initiated development of a series of financial policies intended to ensure appropriate and systematic cash management and financing.

Projected reference case financial results indicate noticeable rate pressure in the first half of the study period due in large part to planned hydro unit upgrades, along with the need for significant distribution system capital upgrades requiring sharp increases in financing and increased distribution maintenance costs, both recommended by the 2022 PLM distribution study. These increased levels of investment and expense reflect the need to respond to anticipated electrification driven load growth. Coupled with increased costs and a compound annual load growth of about 1%, average retail rates are anticipated to grow at a compound annual growth rate (CAGR) of 3.9%, roughly doubling over the 20-year period.

Interestingly enough, while the Full Electrification case includes an estimated additional $15 million of distribution investment, mainly substation and feeder upgrades preliminarily identified by PLM based on the Full Electrification load forecast, retail rates grow at a compound annual growth rate of only 3.3% and are about 9.5% lower than those in the reference case at the end of the period. While electrification is expected to increase revenue requirements, the related growth in load is expected to somewhat mitigate the impact on rates.

As electrification intensifies, absolute grid reliability will become critical. At the same time, the specter of increased electric costs and rates highlights the need to consider electric costs in a broader "bills not rates" context. As customers adopt more electrification measures and their electric bill increases, other energy uses such as gasoline, heating oil, and propane will be displaced, reducing those bills and more than offsetting increases in the electric bill, resulting in lower total energy costs. Morrisville believes it will be important to remind customers of these tradeoffs through intentional educational programs to promote adoption of beneficial electrification. It will also be important to carefully choose the pace of electrification and social programs that are to be included in electric rates so as not to jeopardize the competitive advantage of electrification versus fossil fuels, potentially throttling adoption of electrification measures.

TABLE OF CONTENTS

List of Tables

List of Figures

INTRODUCTION

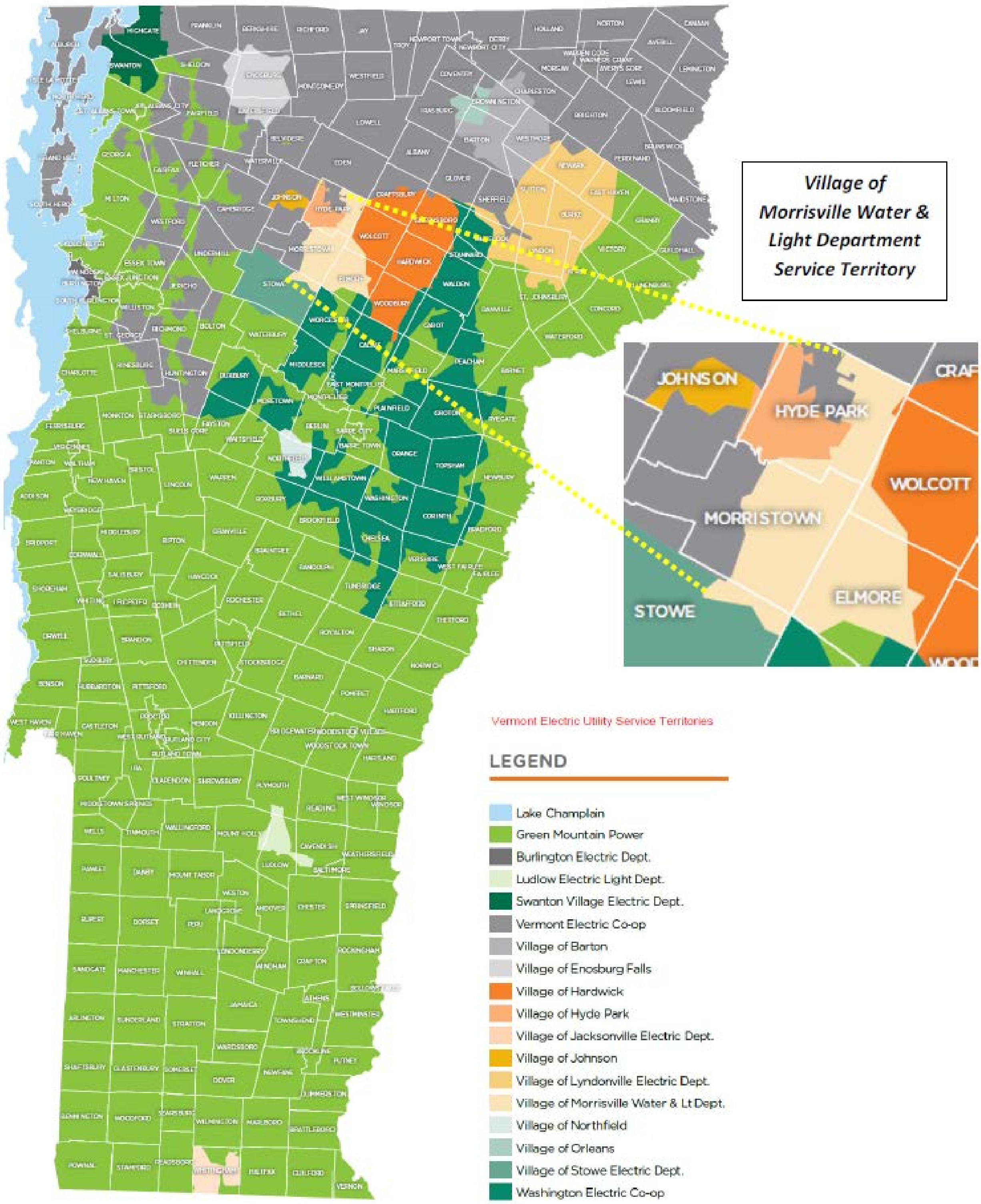
Located in Lamoille County in north central Vermont, the Village of Morrisville Water & Light Department (MWL) was incorporated in 1895. Its service territory (shown on the map below) encompasses the Village of Morrisville as well as portions of seven of the surrounding towns: Morristown, Elmore, Hyde Park, Morrisville, Stowe, Johnson and Wolcott. About 70% of Morrisville's customers are served within the village and town portions of Morrisville. Morrisville serves approximately 4,200 retail customers.

MWL 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 MWL is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

MWL's distribution system serves a mix of residential and small commercial customers. Residential customers make up over 80% of the customer mix while accounting for almost half of MWL's retail kWh sales. Approximately 648 small commercial customers (about 15%) make up a little over half of retail usage with the remaining retail sales going to public street and highway lighting customers.

Consistent with regulatory requirements, every three years MWL 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. MWL's Integrated Resource Plan (IRP) is intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

Figure 1: MWL's Distribution Territory



VERMONT PUBLIC POWER SUPPLY AUTHORITY

The Vermont Public Power Supply Authority (VPPSA) is a joint action agency established by the Vermont General Assembly in 1979 under Title 30 VSA, Chapter 84. It provides its members with a broad spectrum of services including power aggregation, financial support, IT support, rate planning support and legislative and regulatory representation. VPPSA is focused on helping local public power utilities remain competitive and thrive in a rapidly changing electric utility environment.

MWL 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:

- Morrisville Water & 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
- Ludlow Electric Light Department
- Lyndon Electric Department[1]
- Northfield Electric Department
- Village of Orleans
- Swanton Village Electric Department

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

[1] The Villlge of Lyndonville Electric Department became Lyndon Electric Department in July 2023 after a town of Lyndon and village of Lyndonville government merger.

SYSTEM OVERVIEW

In 2022 MWL's peak demand in the winter months was 8,502 kW and 9,143 kW during the summer and shoulder months. Annual energy retail sales for 2022 were 45,788,872 kWh and the annual load factor for 2022 was 61.8%.

MWL is connected to the transmission systems of Green Mountain Power Corporation (GMP) to the north, Vermont Electric Power Company (VELCO) to the south in Stowe, and the Hardwick Electric Department (and eventually GMP) to the east.

Table 1: MWL's Retail Customer Counts

	2018	2019	2020	2021	2022
Residential (440)	3,568	3,498	3,602	3,644	3,736
Small C&I (442) 1000 kW or less	648	644	662	666	674
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	3	4	4	3	3
Public Authorities (445)	0	0	0	0	0
Interdepartmental Sales (448)	0	0	0	0	0
Total	**4,219**	**4,146**	**4,268**	**4,313**	**4,413**

Table 2: MWL's Retail Sales (kWh)

	2018	2019	2020	2021	2022
Residential (440)	21,688,925	21,460,395	22,894,833	23,099,459	23,095,882
Small C&I (442) 1000 kW or less	24,062,506	23,681,266	23,132,910	23,253,349	23,398,581
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	37,441	38,148	37,380	37,312	37,250
Public Authorities (445)	0	0	0	0	0
Interdepartmental Sales (448)	0	0	0	0	0
Total	45,788,872	45,179,809	46,065,123	46,390,120	46,531,713
YOY	4%	-1%	2%	1%	0%

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

	2018	2019	2020	2021	2022
Peak Demand kW	9,143	8,671	9,087	9,183	8,725
Peak Demand Date	07/02/18	07/30/19	07/27/20	08/11/21	01/15/22
Peak Demand Hour	15	17	16	19	18

[2] Noncoincident Peak (NCP)

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

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

SYSTEMS PLANS

This chapter describes MWL's operating systems including the distribution system itself, but also support systems such as the customer information system (CIS), geographic information system (GIS), and automated metering infrastructure (AMI).

FINANCIAL ANALYSIS

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

ACTION PLAN

This chapter includes a timeline of specific actions the MWL expects to take as a result of this IRP.

APPENDIX

The appendix includes a series of supporting documents and reports.

ELECTRICITY DEMAND

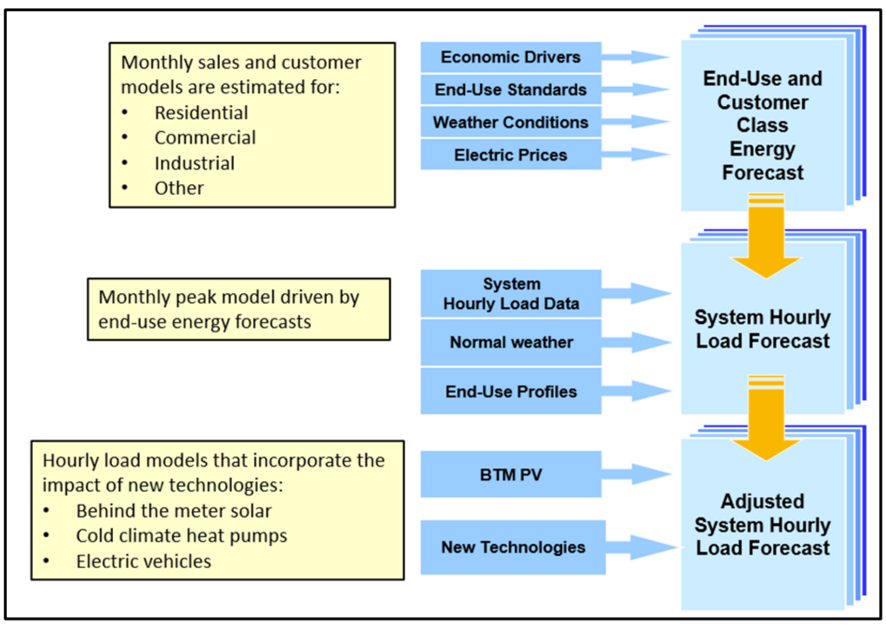
I. ELECTRICITY DEMAND

ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast MWL'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 2.[4]

Figure 2: Forecasting Process



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

ENERGY FORECAST RESULTS

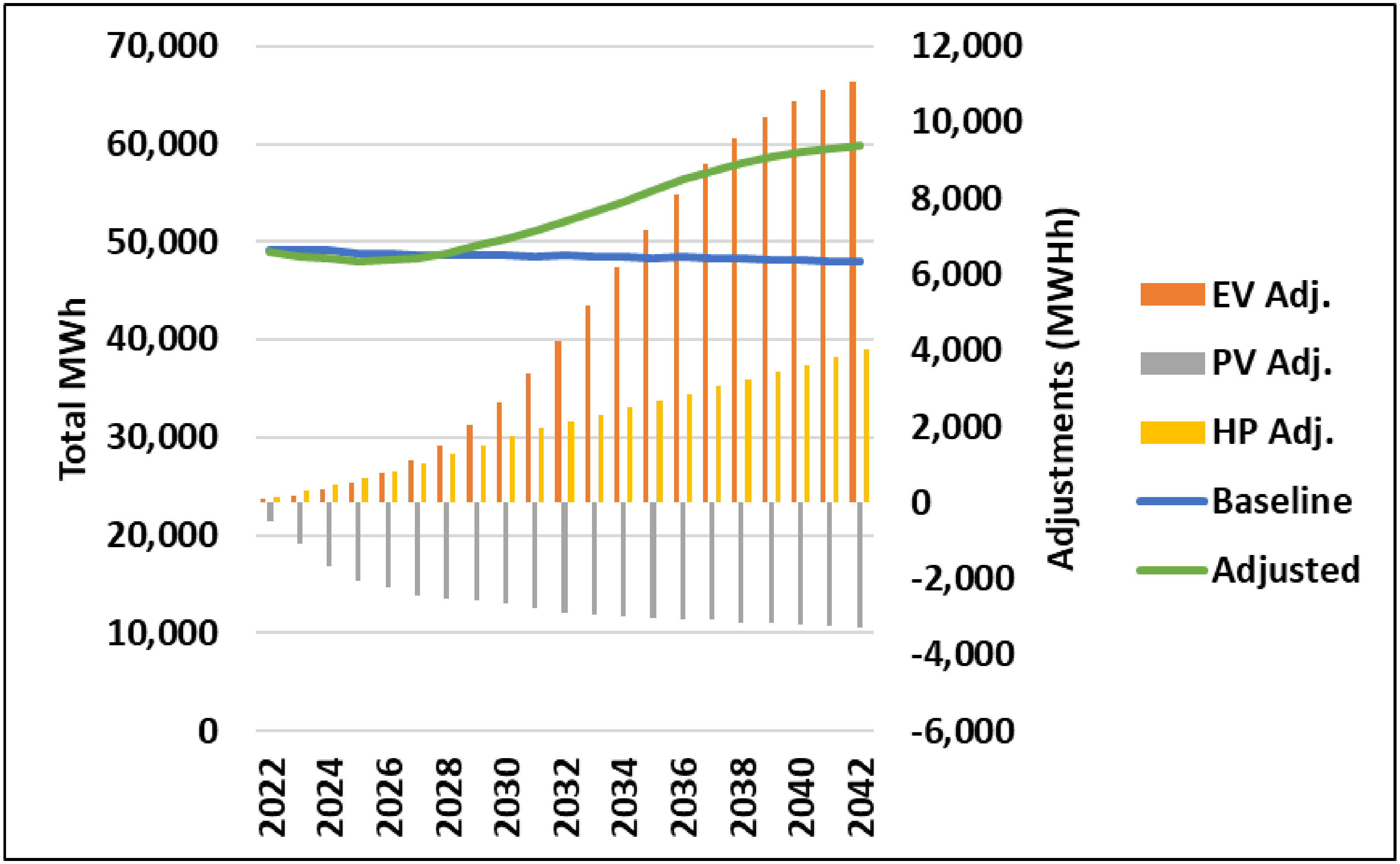
Table 4 shows the results of the Baseline Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is declining 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%).

Table 4: Adjusted Energy Forecast (MWh/Year)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2023	1	49,100	194	-1,078	295	48,511
2028	5	48,634	1,518	-2,530	1,275	48,898
2033	10	48,496	5,191	-2,928	2,315	53,073
2038	15	48,301	9,585	-3,135	3,246	57,998
2042	20	47,976	11,043	-3,289	4,028	59,758
CAGR		-0.1%	21.2%	5.5%	13.3%	1.0%

Figure 3 shows how these adjustments impact the baseline trend.

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES

To form a high case, we assumed that the market saturation rate for net-metered solar remains the same as in the base case, and that EVs and HPs reach about 200% saturation. This is substantially faster adoption than the VSPC assumed for the 2021 LRTP, and it means that most households and buildings will have two heat pumps and two electric vehicles by the end of the forecast period. These assumptions are intended to result in a reasonable approximation of the kind of growth in energy use that is possible: 3.4% per year. This growth rate results in a 100% increase (a doubling) in electricity use by 2042.

Table 5: Energy Forecast – High Case (MWH)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2023	1	49,100	194	-1,078	295	48,511
2028	5	48,634	4,555	-2,530	6,377	57,036
2033	10	48,496	15,572	-2,928	11,575	72,714
2038	15	48,301	28,756	-3,135	16,229	90,152
2042	20	47,976	33,129	-3,289	20,138	97,954
CAGR		-0.1%	27.7%	5.5%	22.3%	3.4%

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	49,100	194	-1,078	295	48,511
2027	5	48,634	759	-2,530	638	47,501
2032	10	48,496	2,595	-2,928	1,157	49,321
2037	15	48,301	4,793	-3,135	1,623	51,582
2042	20	47,976	5,521	-3,289	2,014	52,223
CAGR		-0.1%	17.3%	5.5%	9.6%	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 about +/-0.3% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 1.3-2.4% per year. The winter peak is presently less than the summer peak, but this is expected to change by 2027. Finally, the timing of the peak hour is expected to be stable in the early evening hours.

Table 7: Summer Peak Forecast (MW)

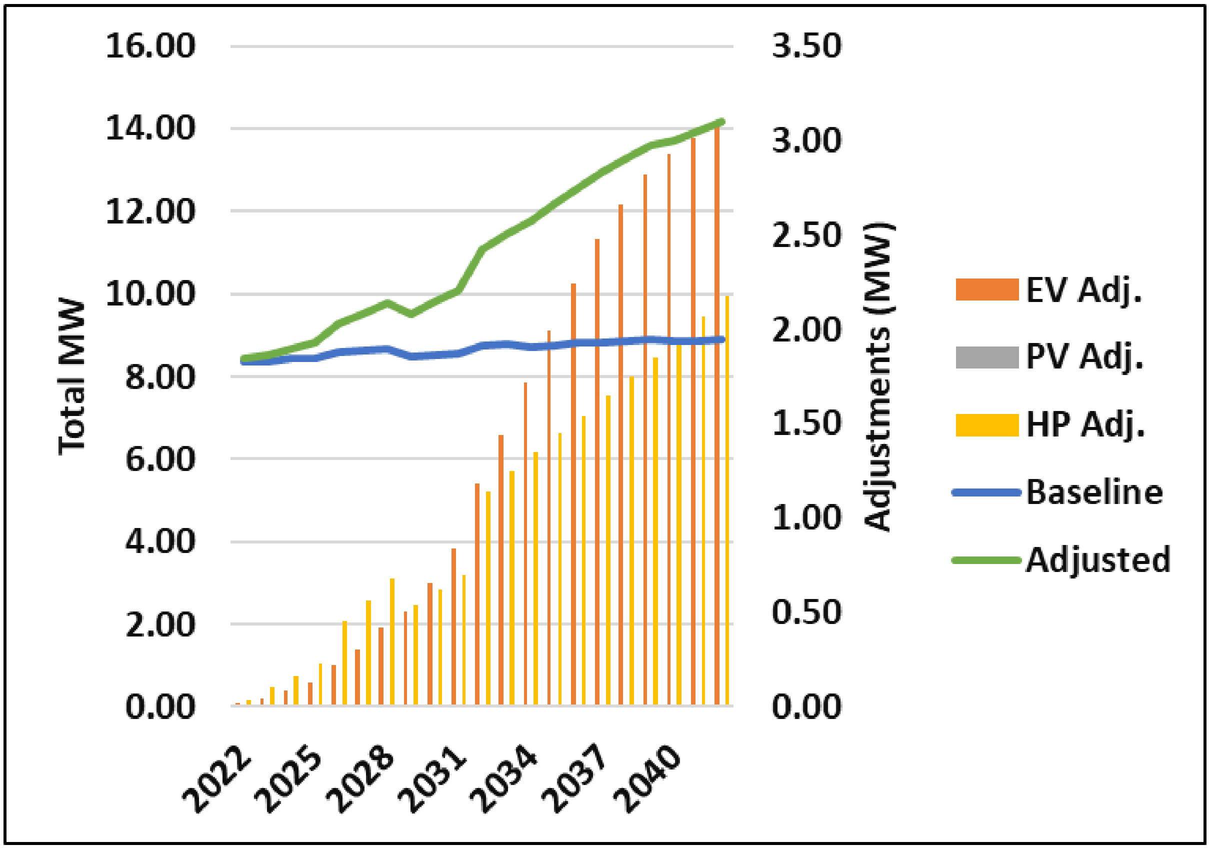
Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	8.9	0.0	0.0	0.0	9.0
2027	5	9.0	0.3	0.0	0.2	9.4
2032	10	9.0	1.0	0.0	0.3	10.3
2037	15	9.2	1.8	0.0	0.4	11.4
2042	20	9.2	2.1	0.0	0.5	11.9
CAGR		0.2%	21.7%		13.1%	1.3%

Table 8: Winter Peak Forecast (MW)

Year	#	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	8.4	0.0	0.0	0.1	8.5
2027	5	8.7	0.4	0.0	0.7	9.8
2032	10	8.8	1.4	0.0	1.3	11.5
2037	15	8.9	2.7	0.0	1.8	13.3
2042	20	8.9	3.1	0.0	2.2	14.2
CAGR		-0.3%	21.9%		15.5%	2.4%

The size of the electrification adjustments can be seen in Figure 4, which shows the winter peak forecast plus adjustments for EVs, HPs and PV. The Adjusted Forecast exceeds the Baseline Forecast immediately as a result of high CAGRs for HPs and EVs.

Figure 4: Adjusted Peak Forecast (MW)



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we adopt the same assumptions from the high case as in the energy forecast. In addition, we assume that a combination of load control and/or time of use (TOU) rate programs are implemented such that incremental loads from EVs and HPs are almost perfectly smoothed out. This assumption enables the system load factor to remain in the 60-65% range. In practice, load control programs could increase the load factor from its present-day 65%. However, some customers are likely to opt-out of such programs, and not all end uses are likely to be cost-effective to control. In any case, under these assumptions, peak load growth may reach 18.2 MW by 2042, which is about 28% 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	8.4	0.0	0.0	0.1	8.5
2027	18	8.7	0.5	0.0	1.7	11.0
2032	18	8.8	1.8	0.0	3.2	13.7
2037	18	8.9	3.3	0.0	4.4	16.6
2042	18	8.9	3.8	0.0	5.5	18.2
CAGR		0.3%	27.7%		22.3%	3.7%

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 not only offset any peak load growth resulting from CCHPs and EVs, but could also improve the system load factor to the point where peak loads could decrease. In the context of the anticipated electrification trends, this outcome is unlikely, however. Furthermore, the existing distribution system is already sufficiently sized to serve present-day peak loads. For these reasons, a low case scenario is not quantified.

TIER III IMPACTS ON THE FORECAST

The provisions of Tier III 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."[5]

Based on the following analysis, the load forecast adjustments for heat pumps and electric vehicles exceed the electrification that is budgeted through Tier III programs. The deviation represents about 366 MWH per year, which is less than 1% of the Year 1 load forecast.

Table 10 shows the budgeted measures from VPPSA's 2023 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. Eighty percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles, and the 123 MWH/Year of new electric loads is in reasonable alignment with the heat pump and electric vehicle adjustments in Table 5 , which shows a 489 MWH increase in electric loads in 2023 due to these technologies.

Table 10: Program Year 2023 Tier III Measures & Their Expected Impact on Load

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
CCHP	44	1.3	58
Ebike	5	2.1	10
EV	12	2.8	33
Fork Lift / Golf Cart	1	3.4	3
HPWH	5	1.2	6
Lawn Mower	2	0.9	2
Smart t-stats	2	0.0	0
WBHP	7	1.6	11
Yard care	4	0.1	0
Total	81		123

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

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 for controlling refrigeration loads and open-source Electric Vehicle Supply Equipment (EVSE). The EVSE pilot is particularly promising because it is 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 a potentially cost-effective way to manage load. As a result, VPPSA is exploring innovative rates that may include Time-of-Use (TOU) based rates. This effort may inform rates applicable to both residential electric vehicle chargers and public charging stations, as well as providing rate research that can carry over into more generalized load management efforts.

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, MWL's reference 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.

MWL presently has about 151 net metered customers and installed capacity of about 2.7 MW. 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, it could lead to a steep 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 by over 20% 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. Importantly, future net metering rules should consider the requirement of all on-grid net metered systems to fully pay for the fair share cost of the use of the electric grid that supports the system.

The final uncertainty is demographic growth in the building stock. If the number of electric customers grows faster than forecast due to greater construction activity, naturally load growth would rise as a result.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

MWL'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 MWL 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 MWL's portfolio.

EXISTING POWER SUPPLY RESOURCES

1. **Brookfield 2023-2027 PPA**
    - Size: 8-10 MW On-Peak, 7-8.5 MW Off-Peak
    - Fuel: Hydro
    - Location: MA HUB
    - Entitlement: 5% On Peak, 3.5% Off Peak
    - Products: Energy, Tier I RECs
    - Term: 1/1/2023 - 12/31/2027

2. **Cady's Falls Hydro**
    - Size: 1.4 MW
    - Fuel: Hydro
    - Location: Morrisville, VT
    - Entitlement: 100%, Owned
    - Products: Energy, capacity
    - End Date: Life of unit
    - Notes: The unit produces Vermont Tier I environmental attributes.

3. **Fitchburg Landfill**
    - Size: 4.5 MW
    - Fuel: Landfill Gas
    - Location: Westminster, MA
    - Entitlement: 15.65%, PPA
    - Products: Energy, capacity, renewable energy credits (MA I)
    - End Date: 12/31/2031

4. **Hydro Quebec US (HQUS)**
    - Size: 212 MW
    - Fuel: Hydro
    - Location: Quebec
    - Entitlement: 0.192% (0.407) MW, PPA
    - Products: Energy, renewable energy credits (Quebec system mix)
    - End Date: 10/31/2038

5. **Kruger Hydro**
    - Size: 6.7 MW
    - Fuel: Hydro
    - Location: Maine and Rhode Island
    - Entitlement: 18.73% (1.25) MW, PPA
    - Products: Energy, capacity
    - End Date: 12/31/37
    - Notes: MWL 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.

6. **Lawrence Brook**
    - Size: 2.2 MW
    - Fuel: Solar
    - Location: Morrisville, Vermont
    - Entitlement: 100%
    - Products: Energy, VT Tier II RECs
    - End Date: 12/15/2045
    - Notes:

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, MWL 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 Station**
    - Size: 54 MW
    - Fuel: Wood
    - Location: Burlington, Vermont
    - Entitlement: 2.64% (1.32 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 MWL to pay for and purchase 2.64% of the unit's output.

9. **Morrisville #2 Hydro**
    - Size: 1.8 MW
    - Fuel: Hydro
    - Location: Morrisville, VT
    - Entitlement: 100%, Owned
    - Products: Energy, capacity
    - End Date: Life of unit
    - Notes: The unit produces Vermont Tier I environmental attributes.

10. **New York Power Authority (NYPA)**
    - Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
    - Fuel: Hydro
    - Location: New York State
    - Entitlement: 0.511 MW (Niagara PPA), 0.011 MW (St. Lawrence PPA)
    - Products: Energy, capacity, renewable energy credits (New York System Mix)
    - End Date: 9/1/2025 (Niagara), 4/30/2032 (St. Lawrence)
    - Notes: NYPA provides hydro power to MWL under two contracts, which will be extended at the end of their term.

11. **Project 10**
    - Size: 40 MW
    - Fuel: Oil
    - Location: Swanton, VT
    - Entitlement: 9% (3.6 MW), joint-owned through VPPSA
    - Products: Energy, capacity, reserves
    - End Date: Life of unit
    - Notes: As the joint-owner, VPPSA has agreements with MWL to pay for and purchase 9% of the unit's output.

12. **PUC Rule 4.300 (Standard Offer Program)**
    - Size: Small renewables, primarily solar < 2.2 MW
    - Fuel: Mostly solar, but also some wind, biogas and micro-hydro
    - Location: Vermont
    - Entitlement: 0.95% (Statutory)
    - Products: Energy, capacity, renewable energy credits
    - End Date: Varies
    - Notes: MWL is required to purchase power from small power producers through the Vermont Standard Offer Program in 2022, in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with MWL's pro-rata share of Vermont's retail energy sales.

13. Ryegate
    - Size: 20.5 MW
    - Fuel: Wood
    - Location: East Ryegate, VT
    - Entitlement: 0.92% (0.189 MW), PPA
    - Products: Energy, capacity, renewable energy credits (CT Class I)
    - End Date: 10/31/2032

14. Sanders Hydro
    - Size: 1.8 MW
    - Fuel: Hydro
    - Location: Hyde Park, VT
    - Entitlement: 100%, Owned
    - Products: Energy, capacity
    - End Date: Life of unit
    - Notes: The unit produces Vermont Tier I environmental attributes.

15. Seabrook PPA
    - Size: 1,250 MW
    - Fuel: Nuclear
    - Location: Seabrook, NH
    - Entitlement: 0.300 MW, (PPA)
    - Products: Energy, capacity, environmental attributes (Carbon-free nuclear)
    - End Date: 12/31/2034

16. Stetson Wind 2023-2027
    - Size: VPPSA entitled to 20-27MW depending on year
    - Fuel: Wind
    - Location: UN.Stetson
    - Entitlement: 15.8%, 3.2MW
    - Products: Energy, Tier I RECs
    - Term: 1/1/2023 - 12/31/2027

17. Stonybrook Station
    - Size: 352 MW
    - Fuel: Natural Gas, Oil
    - Location: Morrisville, MA
    - Entitlement: 0.352%, (1.24 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 sixth column, followed by the resource's expiration date and whether we assumed that it would be renewed until 2042.

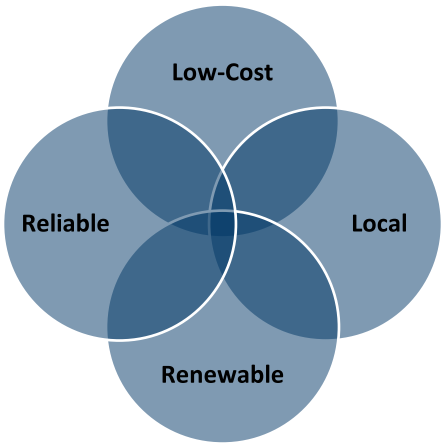
Table 12: 2023 Power Supply Resources

RESOURCE	2023 MWH	% of MWH	Delivery Pattern	Price Pattern	REC	Expiration Date
Brookfield Hydro	0	0%	Firm	Fixed	✓	12/31/27
Cady's Falls	1,694	3%	Intermittent	O&M	✓	Life of unit
Fitchburg Landfill	5,744	11%	Baseload	Fixed	✓	12/31/31
HQUS	2,377	5%	7x16	Formula	✓	10/31/38
Kruger Hydro	4,284	9%	Run of River	Fixed		12/31/37
Lawrence Brook Solar	2,933	6%	Intermittent	O&M	✓	12/15/45
Market Contracts	5,805	12%	Must Take	Fixed		Varies
McNeil	6,473	13%	7x16	O&M + Fuel	✓	Life of unit
Morrisville #2	3,789	8%	Baseload	O&M	✓	Life of unit
NYPA	3,953	8%	Baseload	Fixed	✓	Life of unit
Project #10	39	0%	Peaking	O&M + Fuel		Life of unit
Ryegate	1,442	3%	Baseload	Fixed	✓	10/31/32
Sanders Hydro	946	2%		O&M	✓	Life of unit
Seabrook PPA	2,054	4%		Fixed		12/31/34
Std. Offer Program	997	2%	Intermittent	Fixed	✓	Varies
Stetson Wind	7,438	15%	Intermittent	Fixed	✓	12/31/27
Stony Brook	276	1%	Peaking	O&M + Fuel		Life of unit
TOTAL RESOURCES	50,242					

FUTURE RESOURCES

MWL will seek out future resources that meet as many of the following criteria as possible. Ideally, future resources will meet four criteria by being low-cost, local, renewable and reliable.

Figure 5: Resource Criteria



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

- **Local** resources are located within MWL'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 MWL to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that MWL 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 5,.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

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

1.1 MARKET CONTRACTS

Market contracts are expected to be the most readily available source of electric supply for energy, capacity, ancillary services and renewable attributes (RECs). By conducting competitive solicitations through VPPSA, MWL 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 MWL 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, MWL will continue to welcome the work of the Efficiency Vermont (EVT) and SCVCA in its service territory. MWL 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 MWL continues to implement its energy transformation programs under RES.

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

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

CATEGORY 3: NEW RESOURCES

VPPSA regularly meets with developers throughout New England, and through VPPSA staff, MWL 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, MWL will consider both on and offshore wind PPA's as those opportunities arise.

3.2 GAS-FIRED GENERATION

Project 10 underwent 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 MWL'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, MWL will continue to investigate solar developments both within and outside its service territory.

NET METERING

MWL presently has 134 residential scale (< 15 kW) net metered customers with a total installed capacity of about 1,054 kW. In addition, there are 16 customers who have arrays between 15 and 150 kW, with an installed capacity amount of 1,134 kW. Finally, one customer has a 500 kW system. This totals to 151 net metered systems on the MWL system totaling 2,688 kW.

MWL 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. Since then, MWL has been working with its development partner, Encore Renewables, to develop a storage site in Morrisville.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Lamoille County Planning Commission (LCPC), MWL is part of a Regional Energy Plan[6] that was amended in 2018. According to the Plan, the

> "Lamoille County's Energy Plan is guided by two broad state energy goals. These goals - set for year 2050 – are to decrease the overall energy consumption in Vermont by 33% and transition the state's energy use from 75% non-renewable to 90% renewable. Meeting these energy goals will set the state on a path to meet its greenhouse gas emission reduction targets."[7]

All future resource decisions will be made with this plan in mind. Specifically, MWL will consult with the LCPC on resource decisions that involve potential siting of new resources in Vermont.

[6] The full plan can be found at https://www.lcpcvt.org/?SEC=77A0A7C5-D81B-4DAB-AC09-D59CA8D9A347.

[7] 2015-2023 Lamoille County Regional Plan, Section 3: Where We Live, LCRP 2018, Page 93

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 MWL 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. MWL 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.

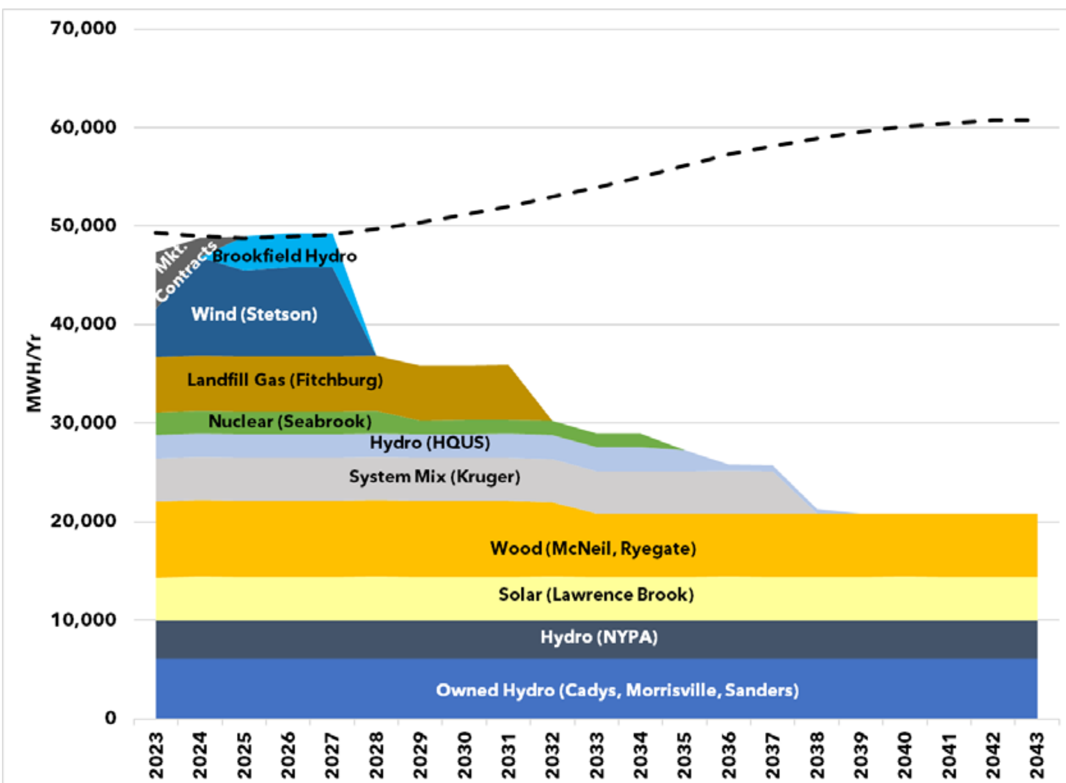
Energy Resource Plan

Figure 6 compares MWL's energy supply resources to its adjusted load. There are two resource decisions that, in total, will affect about 37% of MWL's energy supply between 2023 and 2031. Importantly, the first decision occurs during the first five years of the forecast period (2023-2027), and it will affect about 25% of MWLs energy supply.

DECISION 1: BROOKFIELD HYDRO AND STETSON WIND BY 2027

When the Brookfield Hydro and Stetson Wind contracts expire in December 2027, a 25% deficit forms starting in January 2028. This deficit may be hedged before the start of each calendar year using the annual hedging process. However, the most likely scenario is to extend the term of one or both contracts with Brookfield Hydro and Stetson Wind. A competitive bid process would be used, and the expectation is that these resources can be procured at prevailing market prices.

Figure 6: Energy Supply & Demand by Fuel Type



DECISION 2: FITCHBURG LANDFILL BY 2025

This decision is whether to elect a five-year extension of the Fitchburg Landfill PPA, and it will represent about 11% of MWL's energy requirements in 2031. The contract has had this option since it was signed, and it must be triggered one year in advance of 12/31/26.

Because this resource produces premium RECs that are being sold out-of-state to reduce the overall cost of the portfolio, it does not impact RES compliance. However, its expiration will be just one year before the culmination of RES. As a result, the decision to extend this contract or replace it with another resource will be influenced by RES requirements and any subsequent energy policies that are being considered at that time.

Finally, VPPSA maintains a Monte Carlo analysis of this PPA that it will use to make this decision in the summer of 2025. Please note that

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

Table 13 summarizes the energy resources decisions MWL faces in the coming years.

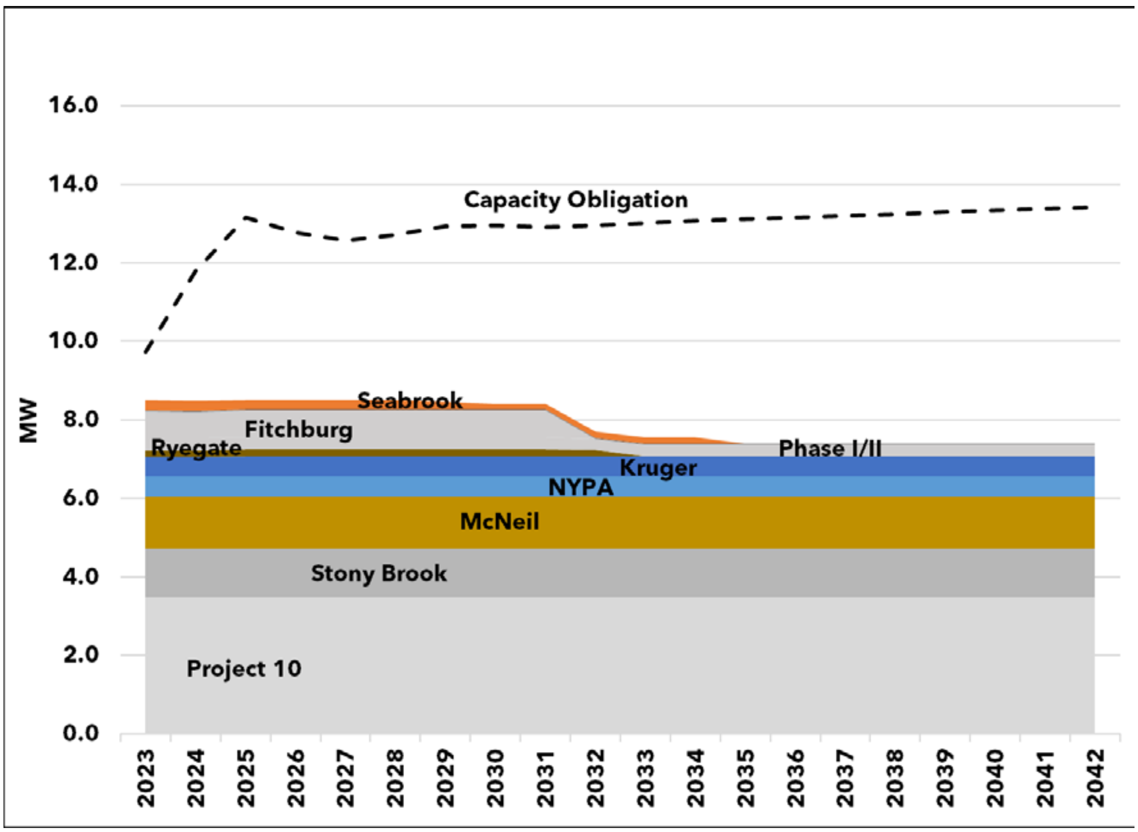
Table 13: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
Brookfield Hydro	2028+	5%	Increase	Yes
Stetson Wind	2028+	10-20%	Decrease	Yes
Fitchburg Landfill Gas	2027-2031	10%	Neutral	Possible

CAPACITY RESOURCE PLAN

Figure 7 compares MWL's capacity supply to its capacity supply obligation (CSO). The CSO is equal to MWL'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 70% of MWL's capacity. In 2023, Project 10 provides about 40%, Stonybrook provides 14% and McNeil provides another 15%.

Figure 7: Capacity Supply & Demand (Summer MW)



Notice that the CSO increases steeply in the first few years of the forecast. This is driven by the assumption that peak loads will grow from their maximum historical level (2018) in future years. In other words, it is not an average, but a maximum from the previous five years of historical data. In any case, MWL 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 Project 10, Stonybrook or McNeil drops for an extended period of time.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because MWL 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, MWL will be provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance[8] (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 MWL'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, MWL could receive up to a $12,800 payment or pay up to a $14,500 penalty during a one-hour scarcity event. This represents a range of plus or minus 15% of MWL's 2023 monthly capacity budget. However, such events occur infrequently (only twice since 2018).

Table 14: Pay for Performance Ranges for One Hour of Project 10 Operation[9]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWH	-$6,300	$3,300	$12,800
15,000	$5,500/MWH	-$9,000	$500	$10,100
20,000	$5,500/MWH	-$11,800	-$2,200	$7,400
25,000	$5,500/MWH	-$14,500	-$4,900	$4,600

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

[9] 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

STORAGE RESOURCE PLAN

As MWL's electric system relies more and more on intermittent resources like solar and wind, it will require the means to maintain reliability to its customers. This will likely include investments in Distributed Energy Resource Management Systems (DERMS) and battery storage.

DERMS can improve both the reliability and cost effectiveness of the grid. They coordinate various communications and control systems systems to determine when energy use occurs, and send price or control signals to reduce energy demand whens supply costs are high.

Battery storage systems are complementary DERMS systems. For example, small scale batteries are almost always controlled by a DERMS, while large scale battery systems are often operated separately. MWL's vision for storage is to adopt a hub, sub-hub and "spoke" approach as follows:

- **Hub**: There are locations on the MWL system where a utility scale (MW scale) grid-tied battery will be quite useful. Critical locations such as Substation 3, a location to serve large loads in the business district or perhaps with huge solar fields to both store energy and address voltage irregularities are examples of these (to be determined) locations.

- **Sub-Hub**: MWL is just beginning to hear of interest in EV charging infrastructure from its community and will need to address an approach to meeting these needs. MWL does not need to be the sole provider or even the "retail" manager, but it will impact the MWL system, so, MWL will be involved regardless.

  Typically, EV charging is powered by having sufficient resource for the type of charger. However, there is interesting technology that enables EV charging to be more ubiquitously located by installing smaller battery banks at either a business partner location or a location of public interest. These units are sized in the 60 to 180 kw range and are then wired to have a 480 v buss, which is sufficient for level 3 charging. Drops from the buss can be stepped down to say level 2 chargers (240v) off the buss. What is interesting is that the batteries can take in electricity whenever it's available and cheap at whatever level happens to be available in a location. Further, this battery, typically used for EV charging, is then available for load shaping and emergency use.

- Spoke: The intent is that once hubs and sub-hubs are identified, then a gap analysis for reliability could be performed to understand where the "end of the line" reliability may still not be covered. MWL would create a home-scale battery program to serve those customers as a means to both assure their reliability and to further create resources to shape the load.

In this model, MWL can envision a series of large circles addressing customers covered by the grid tie batteries, smaller circles to address customers covered by these combo battery / EV stations, and pin points at the end of the various lines, each point taking care of one home. Perhaps there would be two or three large circles in the territory depicting areas effectively served by grid-tied batteries. There may also be ten to thirty smaller circles depicting the smaller units fulfilling MWL's joint EV charging/battery storage at that scale. Finally, there may be hundreds of pinpoints would depict those locations where home scale batteries may make sense.

This blending of both economic cost and value with an attempt to resolve the larger EV charging infrastructure necessities of the future, may provide an elegant, cost-effective manner to assure MWL's customers reliability in the future. Since all these resources can then help lower peaks, avoid blackouts, potentially participate in frequency markets in the future, and other such market-based solutions, this may result in a very strong model for MWL to consider.

RENEWABLE ENERGY STANDARD (RES 1.0) REQUIREMENTS

MWL's obligations under the Renewable Energy Standard (RES) are shown in Table 15. Under RES, MWL must purchase increasing amounts of electricity from renewable sources. Specifically, its Total Renewable Energy (Tier I) requirements rise from 63% in 2023 to 75% in 2032, and the Distributed Renewable Energy (Tier II) requirement rises from 4.6% in 2023 to 10% in 2032. Note that this plan assumes that both the Tier I and Tier II requirements are maintained at their 2032 levels throughout the rest of the study period.

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

Table 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
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%	10.67%

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[10]…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.

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).

Table 16: ACP Prices[11] ($/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

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.

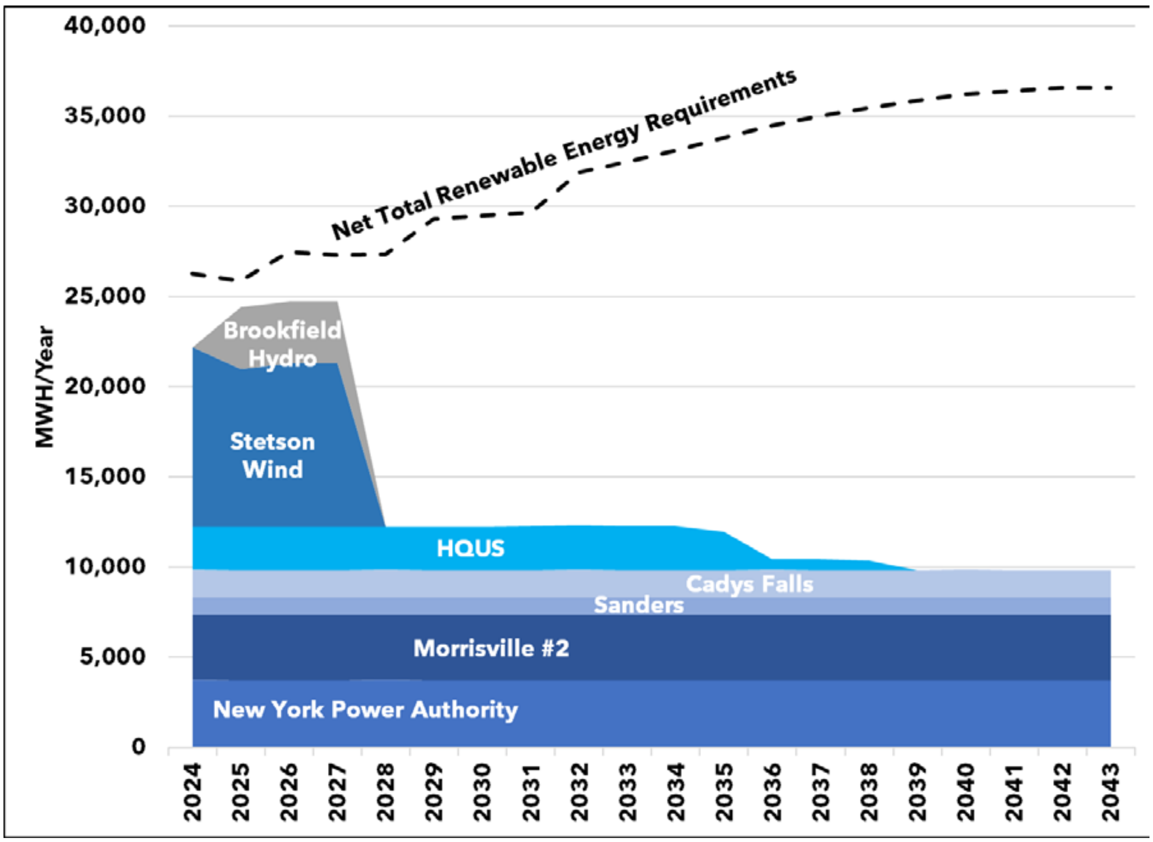
[10] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2023 and 2027, MWL's Net Tier I requirement is about 27,000 MWH per year. MWL owns seven resources that contribute to meeting the Net Tier I requirement as shown in Figure 8. These resources add up to about 24,000 MWH per year or about 90% of MWL's Net Tier I requirement. Through 2027, the remaining Net Tier I requirement (deficit) is about 2,700 MWH per year.

Figure 8: Tier I - Total Renewable Energy Supplies

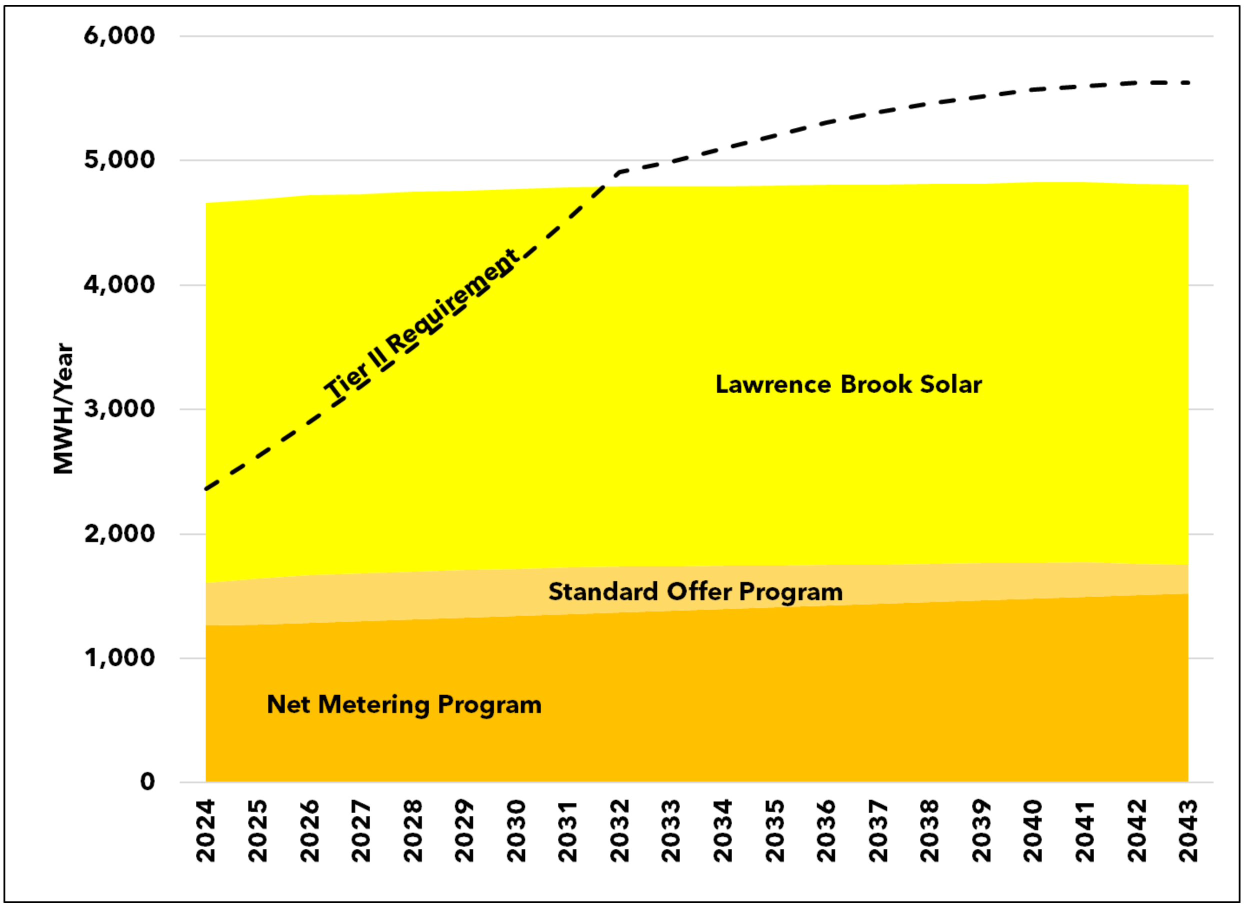


MWL is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). These are presently the lowest cost source of Tier I-compliant RECs in the region, and their price has ranged from a low of $1.00 to a high of $10.00 per MWH over the past five years. At the current price of $10/MWH, the cost of complying with Net Tier I between 2024 and 2027 with ME II RECs would average about $43,000 per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 9 shows MWL's Distributed Renewable Energy (Tier II) requirement, which rises steadily from 2,500 MWH in 2023 to 5,000 MWH in 2032. This requirement is being met with a combination of net-metered, standard offer program and the Lawrence Brook solar resources. Between 2023 and 2029, the surplus may be banked or sold to other entities.

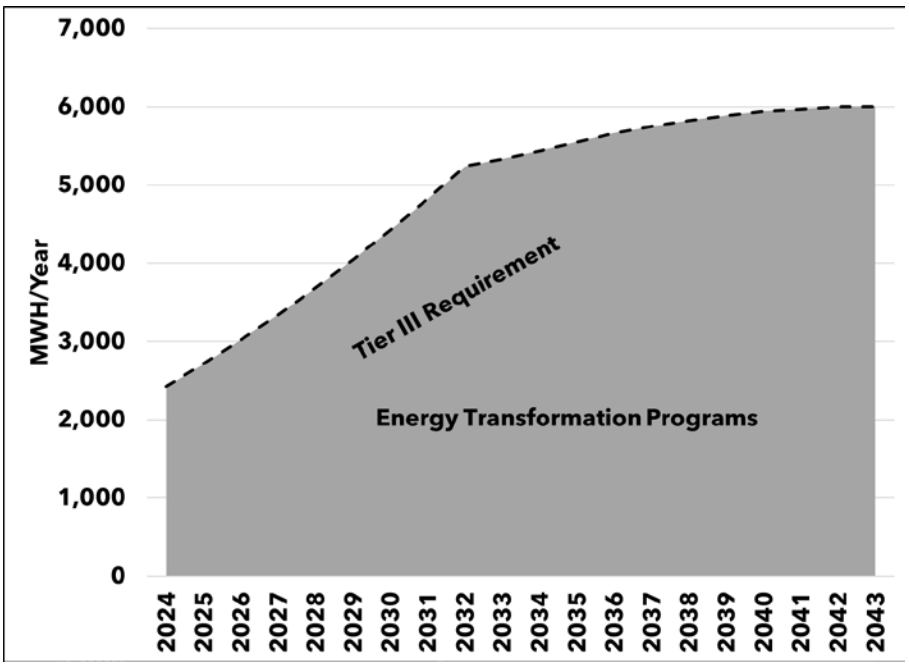
Figure 9: Tier II - Distributed Renewable Energy Supplies



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 10 shows MWL's Energy Transformation (Tier III) requirements, which rise from about 2,400 MWH in 2024 to 5,200 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 10. These programs cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. More detail on these programs can be found in Appendix A (VPPSA's 2023 Tier 3 Annual Plan) and in the following section.

Figure 10: Energy Transformation Supplies



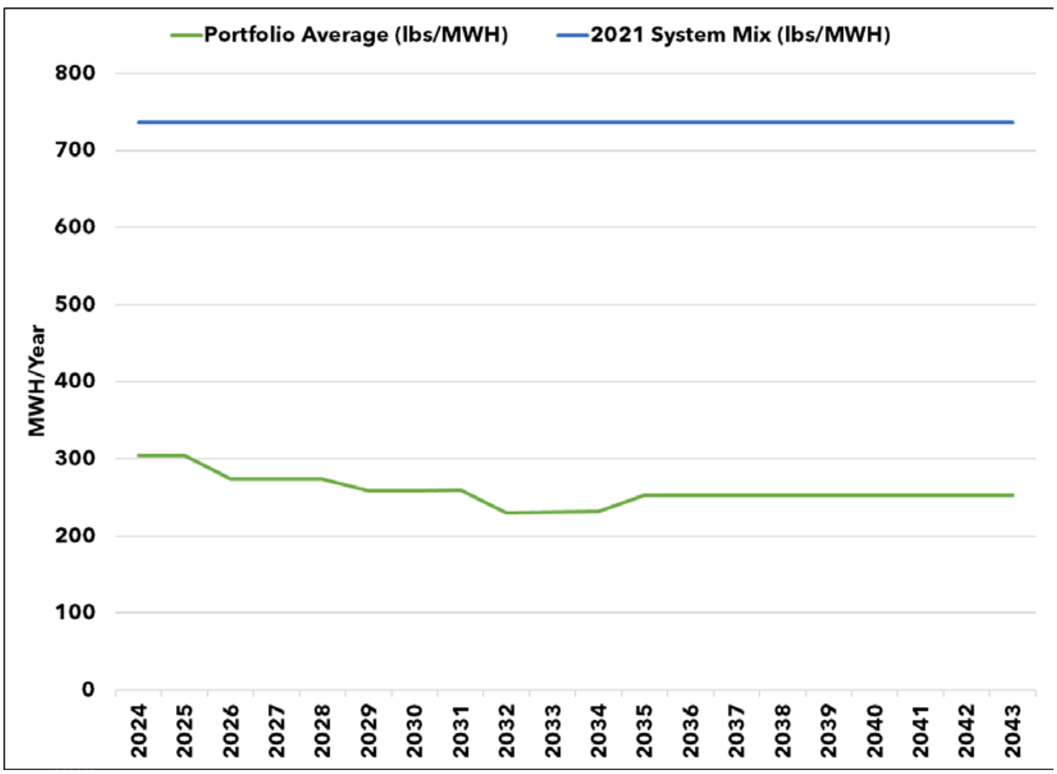
In the event that prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. In any event, MWL will follow a three-part strategy to fulfill its Tier III requirements.

- ✓ 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 minimize costs across both Tier II and Tier III requirements.

CARBON EMISSIONS AND COSTS

Figure 11 shows an estimate of MWL's carbon emissions rate compared to the 2021 system average emissions rate in New England[12]. The emissions rate in 2024 is expected to be about 300 lbs/MWH, which includes the carbon-free emissions attributes of Seabrook Station, a nuclear generator in Seabrook, NH. Carbon emissions continue to decrease over time as the RES program requirements increase and bottom out in 2032 at about 230 lbs/MWH. This compares favorably to the carbon emissions rate of the 2021 New England System Mix, which is a proxy for the fossil fuel emissions rate in the region.[13] Finally, the emissions rate remains stable after 2032 because this plan assumes that the RES requirements will be maintained.

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



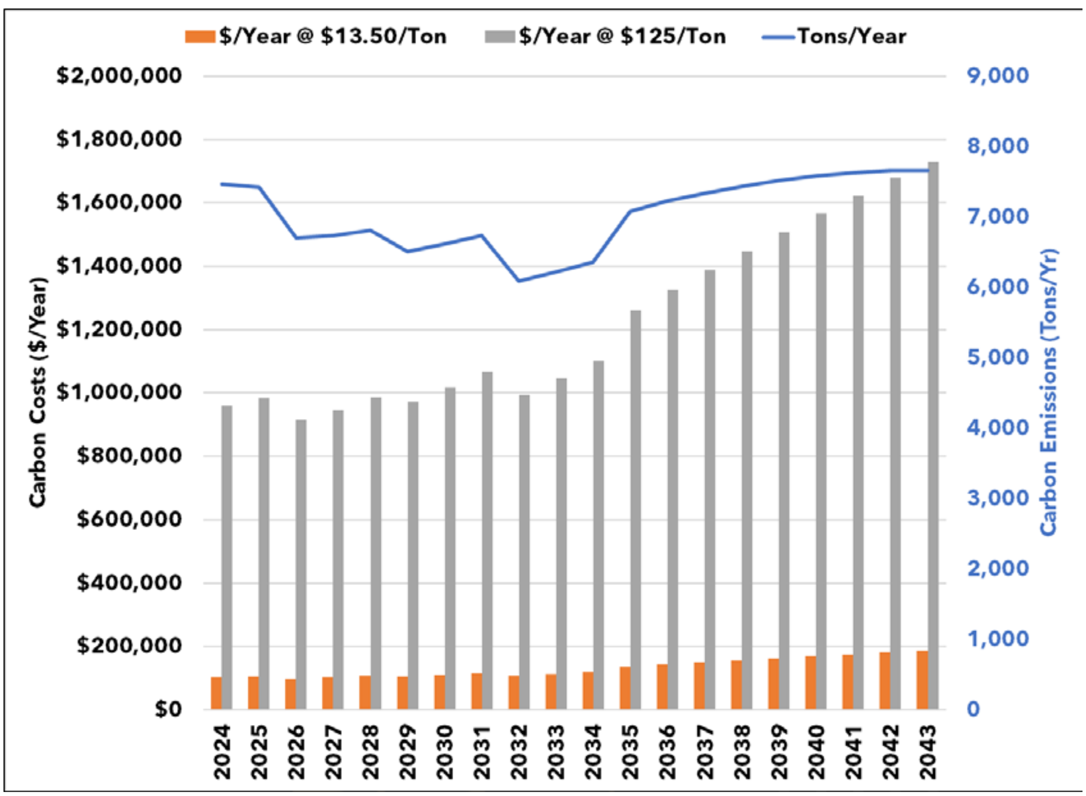
[12] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

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

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 7,000 tons/year in 2024 down to 6,000 tons/year in 2032. Emissions rise after 2032 as electrification increases load while the RES requirements remain the same.

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 2024 is about $104,000 per year and about $107,000 per year in 2032. Using AESC prices, the cost fluctuates around $1 million per year between 2024 and 2032.

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



RES 2.0 REQUIREMENTS

Because there is discussion in the Vermont legislature to increase the RES requirements, we have analyzed the impact of a 100% by 2030 Tier I requirement and a doubling of the Tier II requirement. It is worth noting the importance of carefully managing the combined pace of electrification and social programs that are to be included in electric rates so as not to jeopardize the competitive advantage of electrification versus fossil fuels, potentially throttling adoption of electrification measures.

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 18% in 2042. Figure 13 shows the year-by-year trajectory of these changes to the RES.

Figure 13: RES 2.0 Requirements

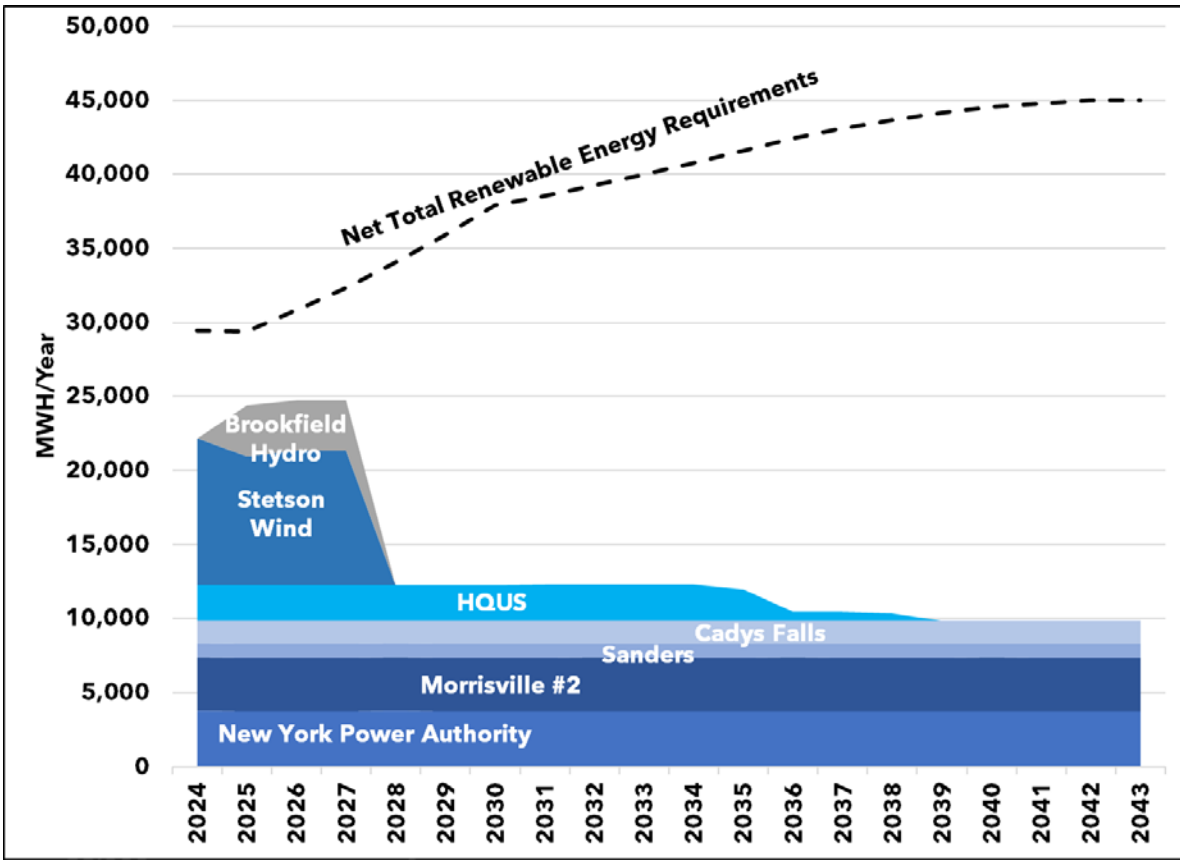
Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: (A) - (B)	Tier III: Energy Transformation
2023	65.0%	60.4%	4.6%	4.7%
2024	70.0%	64.8%	5.2%	5.3%
2025	75.0%	65.0%	10.0%	6.0%
2026	80.0%	68.0%	12.0%	6.7%
2027	85.0%	71.0%	14.0%	7.3%
2028	90.0%	74.0%	16.0%	8.0%
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%
2042	100.0%	80.0%	20.0%	18.0%

TIER I - TOTAL RENEWABLE ENERGY PLAN

Under a 100% by 2030 Tier I requirement, MWL 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, MWL's requirement would rise from 30,000 MWH per year in the 2024 to about 38,000 per year in 2030.

Figure 14: Tier I Requirements Under RES 2.0

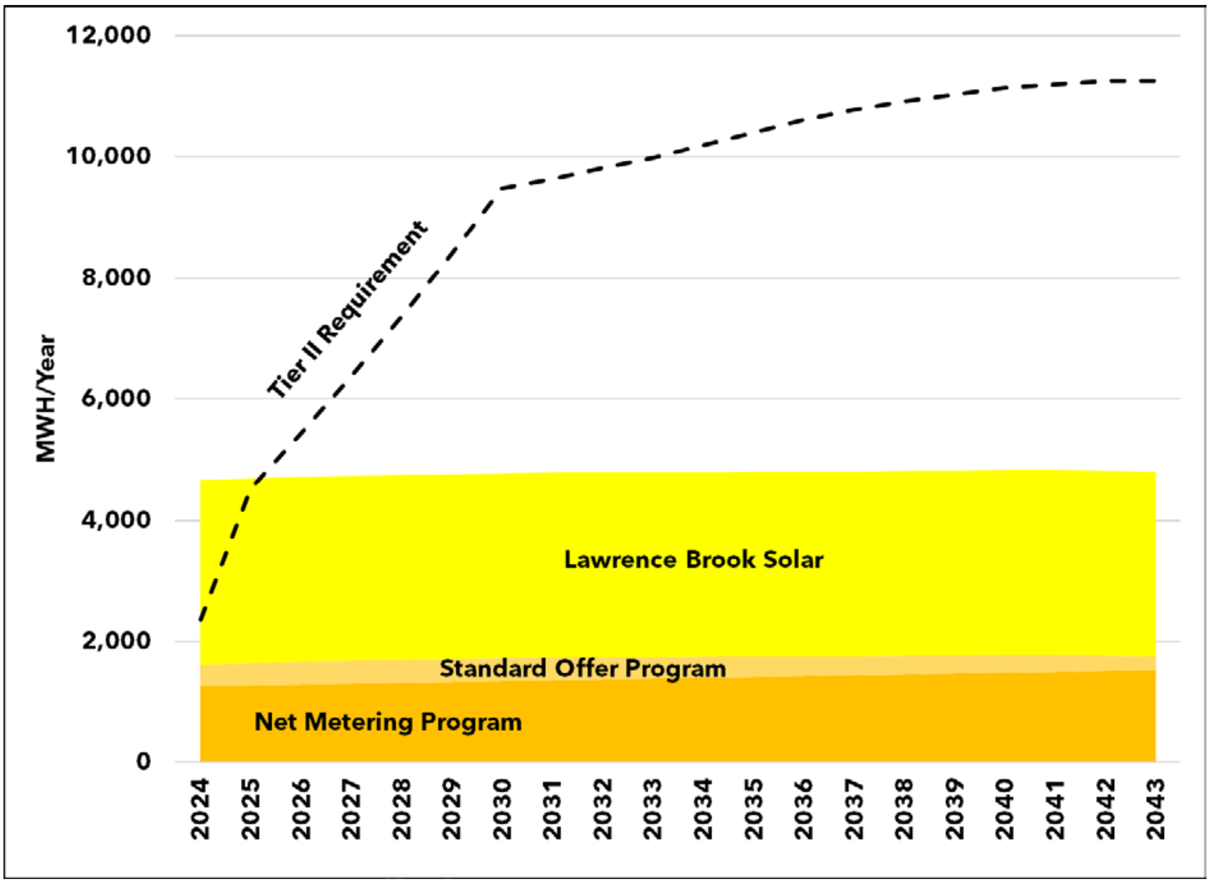


MWL could meet this requirement by purchasing any number of hydro resources in New England, but it could also purchase a wind resource or some combination of the two.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The impact of a 20% by 2030 Tier II requirement is shown in Figure 15. In 2030, the requirement rises to about 9,500 MWH per year. An additional 3.5 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.

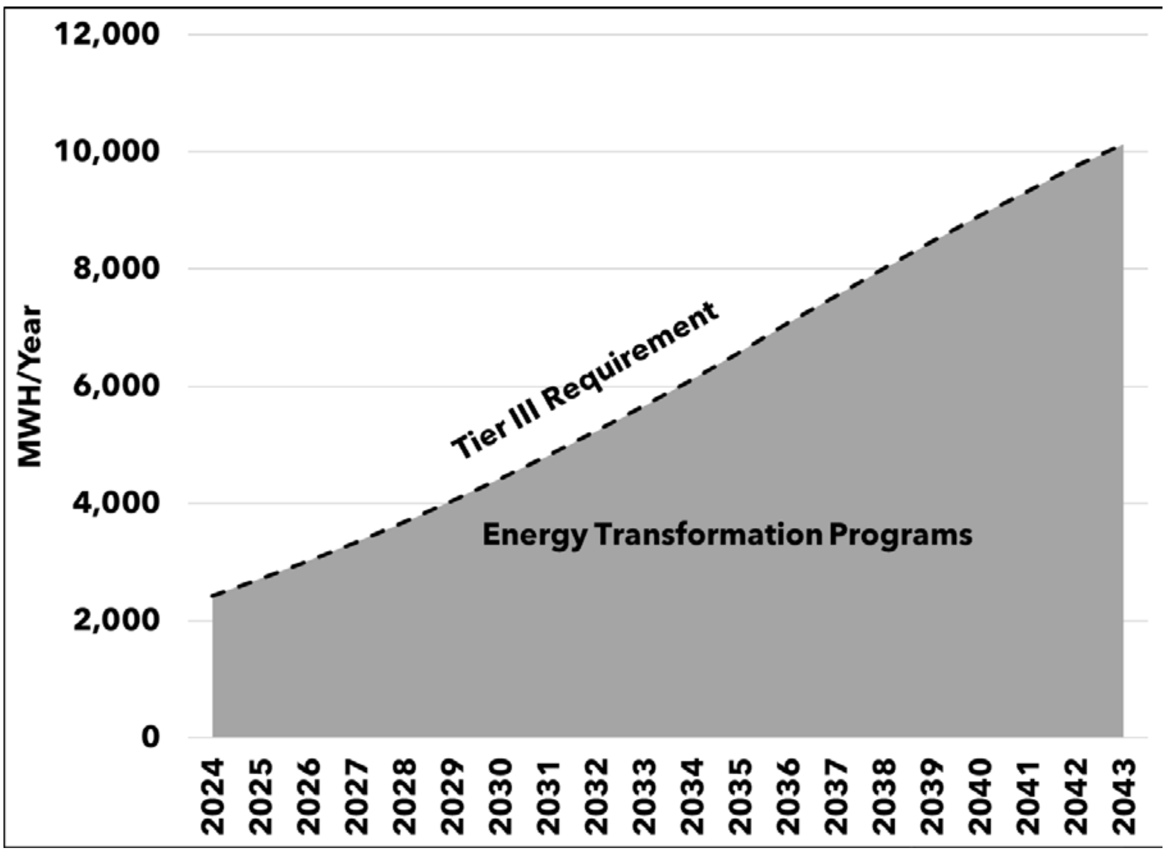
Figure 15: Tier II Requirements Under RES 2.0



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 16 shows MWL's Energy Transformation (Tier III) requirements, which rise from about 2,000 MWH in 2024 to 10,000 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.

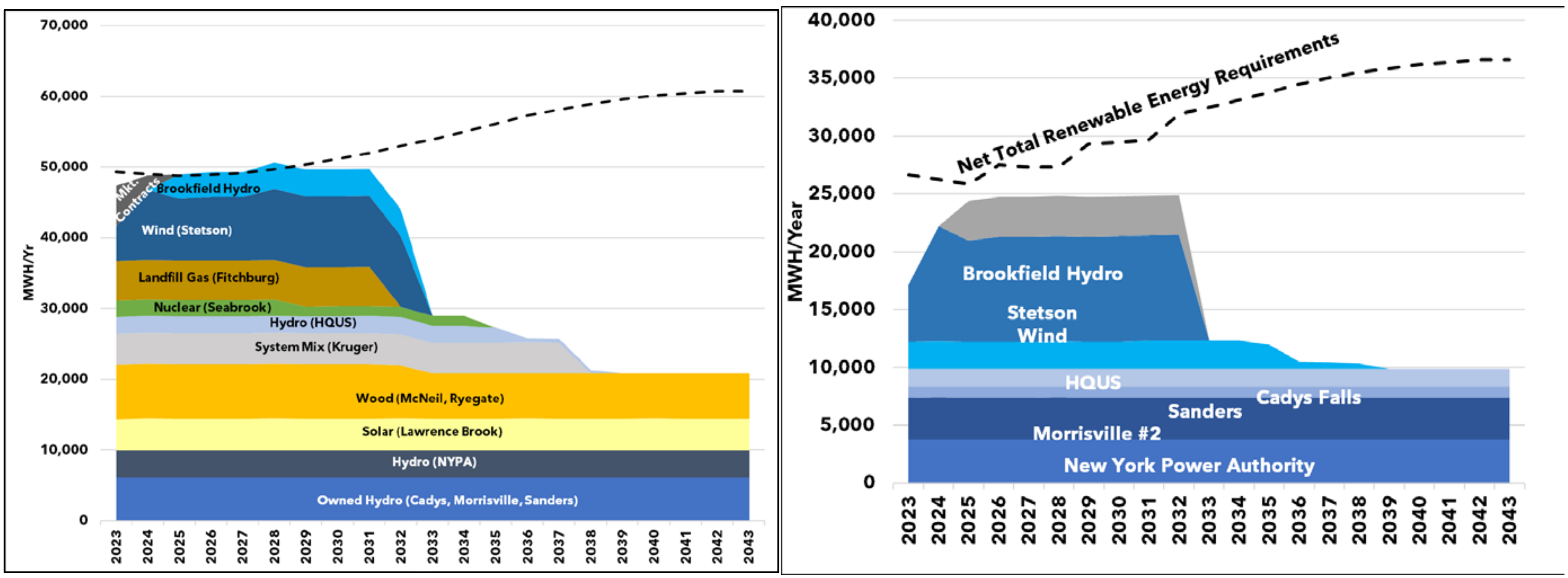
Figure 16: Tier III Requirements Under RES 2.0



PROCUREMENT PLAN FOR RES 1.0

Under RES 1.0 requirements, MWL 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. Simply extending the existing contracts with Brookfield Hydro and Stetson Wind would fulfill MWL's energy requirements through 2030. This approach would retain the diversity of the existing resource mix, and MWL's Tier I supply would keep pace with the increasing Tier I requirements, leaving it with a manageable level of REC market exposure.

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



After 2032, RES 1.0 requirements could be maintained by increasing amounts of onshore wind and/or hydro. By this time, offshore wind resources are expected to be available too, and could add further diversity to the portfolio. Offshore wind has several benefits. It has a higher capacity factor than onshore wind while retaining a winter-peaking generation profile. Finally, the Class I RECs would be an effective hedge against the price of buying Tier I RECs for compliance as described below.

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 17 shows that there is a long-term, 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 and Stetson Wind PPAs would need to be extended to 2032. This step meets MWL's energy requirements, and gives MWL a short-term deficit position between 20% and 35% on Tier I RECs. The third resource, 4.0 MW of new solar, would be required to meet a 20% by 2030 requirement under Tier II.

Figure 18: RES 2.0 Energy Resources Compared to Requirements

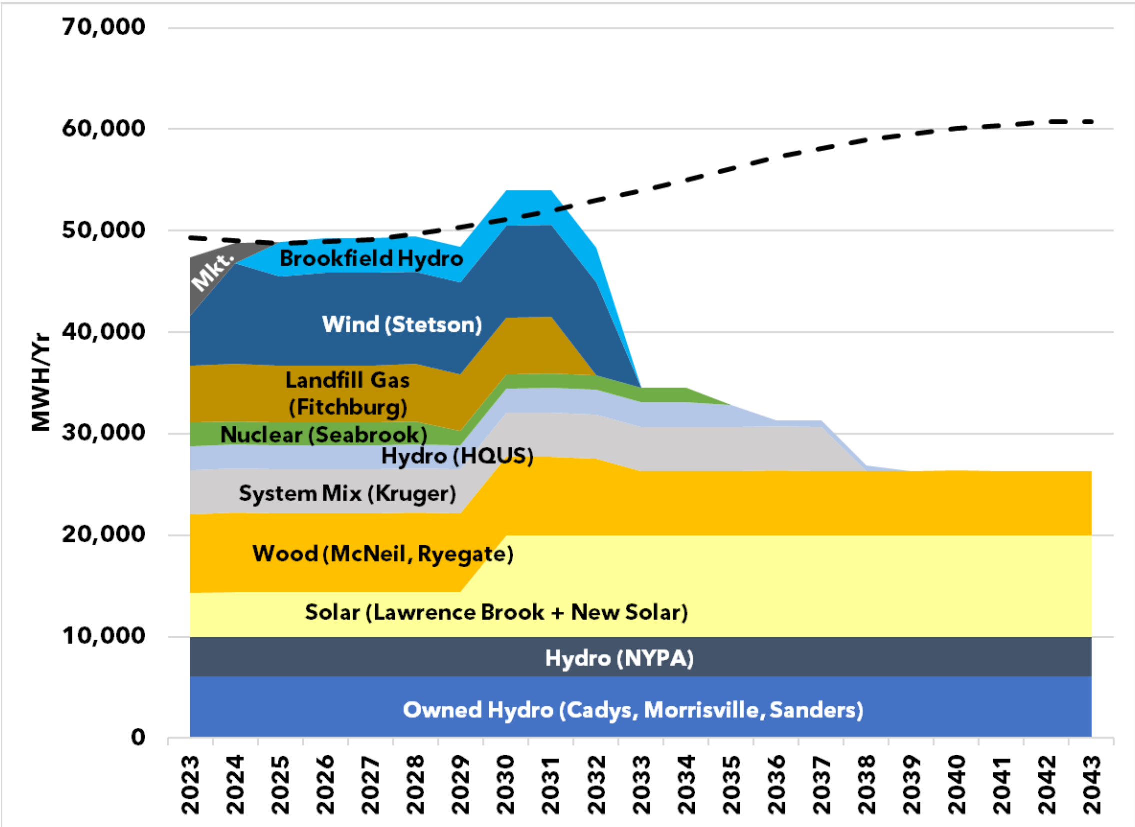
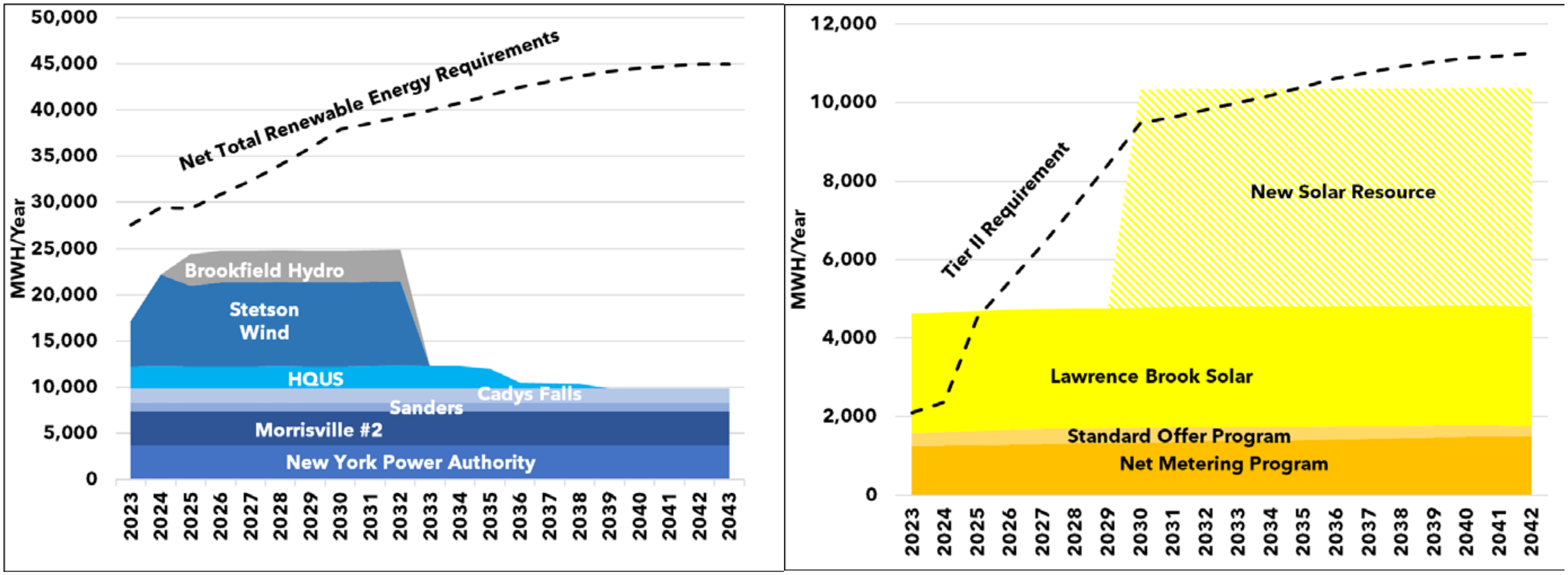


Figure 19: RES 2.0 Tier I and Tier II Resources Compared to Requirements



The timing and magnitude of the hydro, wind, and 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 and, for MWL, desirable, there are some limits and some trade offs. For example, MWL'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. The reason for this is that MWL's energy requirements are fulfilled before its Tier I requirements are fulfilled. As a result, a 100% Tier I requirement would force MWL to either procure too much Tier I RECs or procure an unbundled Tier I REC contract. Both circumstances are commercially manageable. For example, the deficit of Tier I RECs can be purchased as unbundled Tier I RECs in the 1-3 year time frame.

Similarly, there is a limit to the amount of Tier II resources that MWL can reasonably develop and use. MWL's service territory is limited in both area and in suitable terrain. Furthermore, MWL already has sufficient volumes of existing daytime resources during the summer months, namely the Lawrence Brook 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, MWL already has enough daytime, Tier II resources. Procuring more would force MWL 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 DESCRIPTION

Details regarding MWL transmission supply, sub-transmission and distribution facilities is provided below.

TRANSMISSION SYSTEM DESCRIPTION

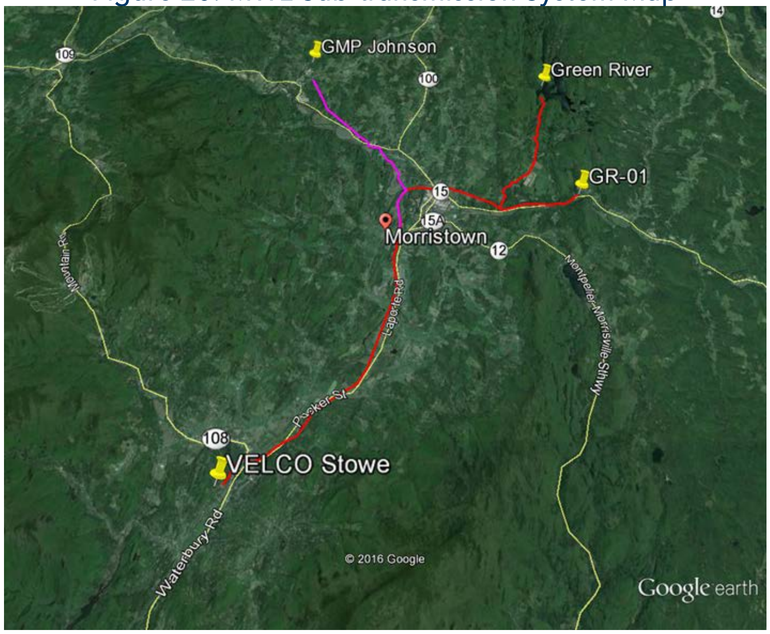
MWL does not directly own any bulk transmission facilities. MWL relies on VELCO (Vermont Electric Power Company) for power deliveries over the state's bulk transmission facilities. MWL has a direct connection to VELCO in Stowe and has indirect connections to VELCO through Green Mountain Power's (GMP) 34.5 kV sub-transmission system at substations in Johnson and Marshfield supported by 115 to 34.5 kV interconnections at VELCO's East Fairfax, Irasburg, Middlesex, Berlin and Barre substations.

VELCO constructed a bulk transmission line extension from Middlesex to Stowe in 2009. In addition, VELCO constructed a 115 kV to 34.5 kV ring bus substation. MWL connects to one section of the ring bus.

SUB-TRANSMISSION DESCRIPTION

MWL owns the 34.5 kV transmission facilities within its own service territory. The MWL transmission system includes 33 miles of 34.5 kV line, interconnected to 1) GMP in Johnson, 2) VELCO in Stowe and 3) Hardwick in Wolcott (eventually GMP in Marshfield) as shown in the figure below.

Figure 20: MWL Sub-transmission System Map



These three sources collectively provide MWL with reliable deliveries of power for distribution to its customers.

The majority of the 34.5 kV lines are built with 336.4 MCM ACSR. The significant exceptions to this are the Cady's Falls to Johnson section of the B22, which is built with 477 MCM Hendrix spacer cable, the line from Substation #6 to Substation #7, which is built with 336 Hendrix spacer cable and a 1.5 mile section of the 3319 line from Substation #3 to the Cady's Falls Plant which is built with 3/0 ACSR. Taps to Hydro station #2 is built with 1/0 AAAC.

These Facilities play an integral role in connecting the GMP system between Waterbury and Marshfield to the GMP system crossing the state from Fairfax to Irasburg. Changes to the MWL transmission system affect GMP, VELCO, Stowe, Hardwick, Hyde Park, Johnson, Washington Electric Cooperative, Vermont Electric Cooperative and could have effects statewide under certain configurations of the bulk transmission system. Conversely, because MWL's system is so tightly intertwined with its neighbors, it is very sensitive to any voltage swings or outages on those surrounding networks.

One item of interest is that MWL's B22 line loading is showing significant flows from Johnson to MWL after the Stowe VELCO Substation was put in service. MWL was expecting to see flows from Stowe VELCO Substation to MWL. That the opposite is occurring is attributable to large wind farms in the northern part of the state. The flows are increasing energy line losses for MWL beyond what was expected when planning studies were completed for the Stowe VELCO Substation. The increased loss situation could be alleviated if the B22 breaker was operated in a normally opened position at GMP's substation in Johnson. However, analysis done by VELCO recommends keeping the B22 line operated in the normally closed position for system reliability purposes. MWL continues to pursue solutions to the issue of increased power flows across its system and the financial burden MWL bears for the unanticipated line losses.

DISTRIBUTION SYSTEM DESCRIPTION

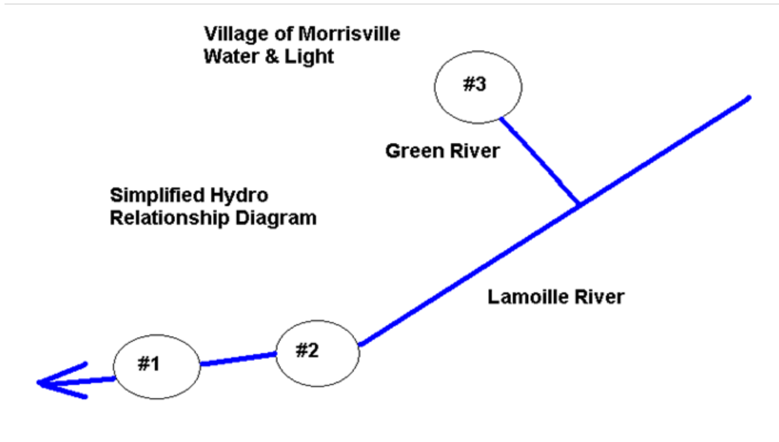
The distribution system includes 180 miles of line operating at 12.5 kV. The 12.5 kV serves three primary objectives. First, energy line losses are kept low. Secondly, it provides the opportunity to maximize feeder backup capabilities. Finally, it improves overall service quality for our customers. Remaining work included one step down transformer. MWL anticipates completion by 2024.

MWL-OWNED INTERAL GENERATION

MWL owns and operates three generating stations known as Cady's Falls (Plant #1), Morrisville (Plant #2), and Green River (Sanders) (Plant #3). All three of MWL's generating stations are hydroelectric plants with two turbine/generator units per plant. In total, these plants have a rated capacity of approximately 4.9 MW, produce an annual average of around 7,000,000 kWhs, and meet approximately 14% of MWL's total power requirements.

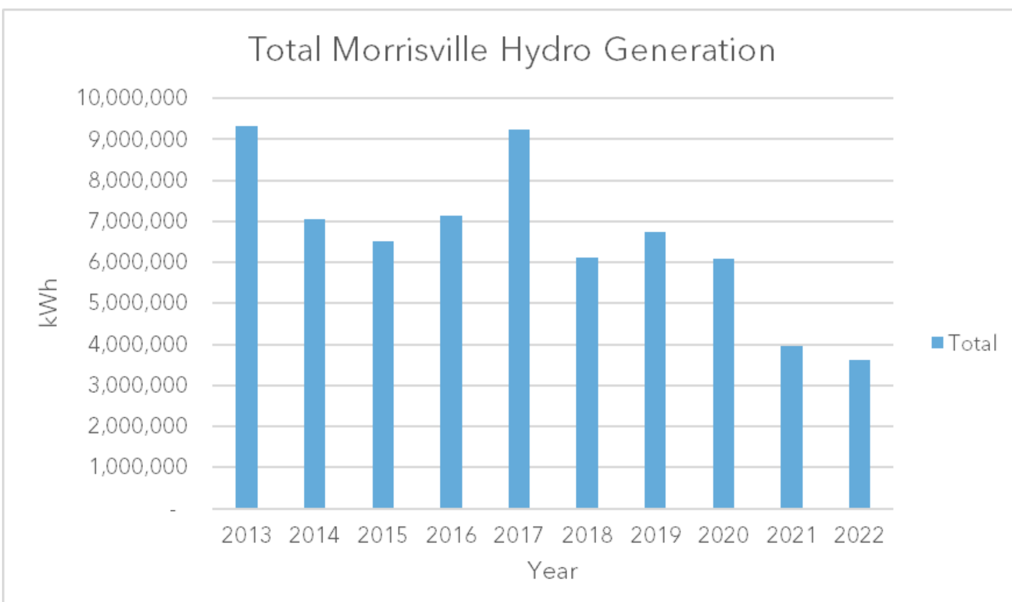
Two of the hydro plants are located on the Lamoille River. One is located on the Green River, a tributary that feeds into the Lamoille River. The relative relationship of each plant is shown in the following simplified diagram. In addition, each plant is discussed briefly below.

Figure 21: Simplified Diagram of MWL Hydro Generation Plants



The following chart summarizes the actual total generation output for the past 10 years (2013-2022).

Figure 22: MWL Historical Hydro Generation



Cady's Falls (Plant #1)

The Cady's Falls Plant is located on the Lamoille River just downstream from the Morrisville Plant.

The Cady's Falls Plant consists of two turbines, an older horizontal unit installed in 1914 and a second, vertical unit installed in 1947. Unit #1 has an output of 600 kW while Unit #2 has an output of 700 kW. The output for both turbines is at 2.4 kV delta and presently connects to the MWL sub-transmission system at 34.5 kV through a padmounted transformer originating at Substation #1.

Morrisville Plant (Plant #2)

The Morrisville Plant is located on the Lamoille River just upstream from the Cady's Falls Plant.

The Morrisville Plant #2 consists of two vertical turbines installed in 1924. The units are rated 600 kW and 1,200 kW at 2.4 kV. The output is connected to a 2.4-34.5 kV step-up transformer that is connected to 1.29 miles of MWL-owned sub-transmission line.

Green River Plant (Plant #3)

The Green River Plant is located on the Green River, a tributary of the Lamoille River and is about 5 miles upstream from the Morrisville and Cady's Falls plants. The Green River Plant structures include a concrete arch dam, an earth dike, a penstock and powerhouse.

The dam has a maximum height of 105 feet and a storage volume of approximately 17,400 acre-feet at spillway crest elevation 1,220 feet.

The Green River Plant consists of two vertical turbines powering two 900 kW generators. The output is at 4.16 kV and steps up to 34.5 kV at Substation #7. Substation #7 interconnects to the MWL transmission system at Substation #6 via a Hendrix spacer cable line.

Lake Elmore

Lake Elmore is included in Morrisville's hydro project boundary since natural outflow from the lake feeds into Elmore Pond Brook which feeds into the Lamoille River above the Morrisville and Cady's Falls hydro plants. MWL does not impact the natural flow except when requested to do so by the Lake Association for the maintenance of docks on the lake.

Other General Generation Information

The Cady's Falls Plant has black start capability. The units operate at bus voltages of 2,300 V.

From an energy perspective, Cady's Falls Plant and Morrisville Plant are considered run-of-the-river though they have some storage capability through ponding and are available year-round. Green River has substantial storage capability, and a high head, but its output is reduced due to draw-down constraints and other factors, including maintaining reservoir levels for the Green River State Park and loon nesting.

MWL operates its hydro plants under a license from the Federal Energy Regulatory Commission (FERC) which includes Water Quality Certificate conditions from the Vermont Agency of Natural Resources (VT ANR). The current 30-year License expired in April 2015. MWL filed a new license application to operate its hydro for an additional 30 years in 2013. MWL expects to have a new license issued from FERC as soon as 2025. MWL continues to operate under the conditions of its existing License. MWL is evaluating options for the Green River hydro facilities based upon the projected final WQC conditions.

MORRISVILLE SUBSTATIONS

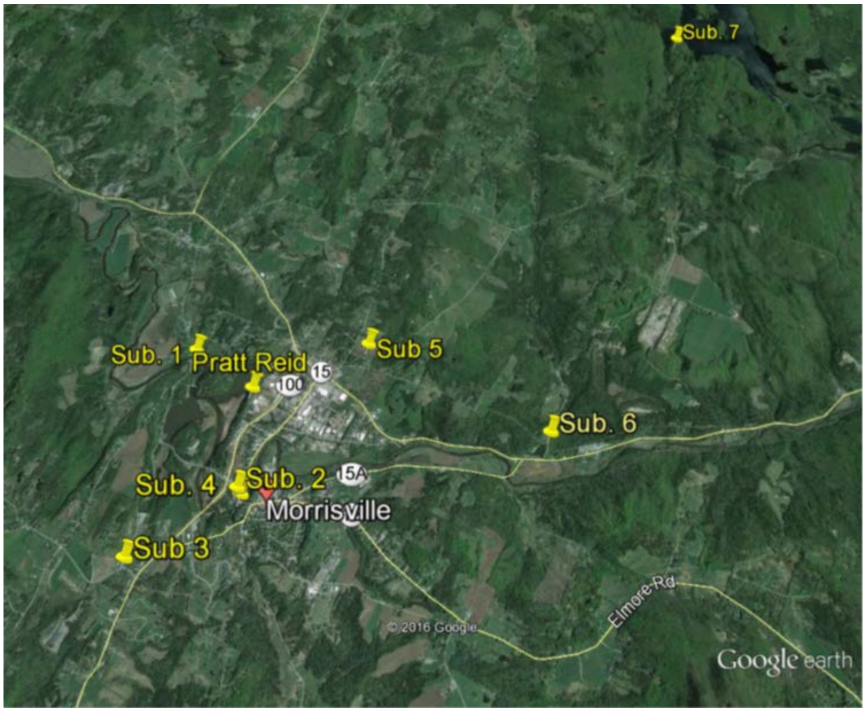
MWL currently operates the substations shown in the following table. Each substation is briefly described below. All substations are in compliance with the National Electric Safety Code.

Table 19: MWL Substation Description

Substation Name	Type	Outages 2018
1	Generation (Cady's Falls Hydro)	n/a
2	Generation (Morrisville Hydro)	n/a
3	Distribution	25
	Feeder Section 1	24
	Feeder Section 2	11
	Total	18
		78
5	Distribution	
	Feeder 1	9
	Feeder 2	32
	Feeder 3	26
	Feeder 4	33
	Total	**100**
6	Switching	n/a
7	Generation (Green River Hydro)	n/a
Johnson 1	Distribution	3
Johnson 2	Distribution	3
Johnson 3	Distribution	2
Pratt-Reid	not active	n/a

The approximate location of MWL's major substation facilities are shown in the map below.

Figure 23: MWL Substation Location Map



Substation #1:

Substation #1 is the step-up substation for the Cadys Falls hydro plant (Plant #1). It consists of a 2,000 kVA 2.4-34.5 kV padmounted transformer. This transformer connects to the B22 line via switch 345PL1 at 34.5 kV. The padmounted transformer and switch pole are shown below.

The recent PLM study recommends that MWL procure a spare GSU transformer for hydro sites (Substation #1, #2, and #7) in the event of failure. The study recommends that MWL replace Substation #1 34.5 kV fuse protection. For more details regarding the PLM Transmission & Distribution System Study recommendations, please see Table 26: MWL PLM Study Summary of Recommendations 2022-2037.

Figure 24: MWL's Substation #1

Substation #2:

Substation #2 is set up similar to Substation #1. MWL installed a 2.4 kV to 34.5 kV 2,500 kVA padmounted transformer to connect generation to the sub-transmission facilities. Substation #2 no longer serves distribution customers.. It is connected to 1.29 miles of MWL owned sub-transmission line. MWL generation is connected to the Northern Loop and B22 bus at MWL Substation #3. The work in Substation #2 to eliminate all equipment except a padmounted transformer was completed in 2017. . The recent PLM study recommends that MWL replace Substation #2 34.5 kV fuse protection within the next 5-10 years

Figure 25: MWL's Substation #2

Substation #3:

Substation #3 serves approximately 1,300 customers in the MWL system. It consists of a 34.5 kV bus with four 34.5 kV circuits and a 7,500 kVA transformer with one three phase 12.5 kV distribution circuit. The distribution circuit serves the southern sections of the MWL service territory with a main line that is underbuilt on the 3329 34.5 kV line. An additional circuit is largely in service to provide service to Copley Hospital. There are no problems anticipated on these circuit for the foreseeable future. The distribution portion of the station completed a rebuild in 2021. Upon completion the station will serve approximately 1,200 MWL retail customers via two 12.47 kV feeder positions with provisions for a third feeder in the future. The substation serves loads at the southern end of MWL's territory off VT Route 100 and the surrounding areas. The new substation transformer is a 55/65°C unit with an ONAN (natural convection cooling) rating of 7.5/9.375 MVA and an ONAF (with fans on) rating of 8.4/10.5 MVA. The transformer has a nominal voltage of 34,400-13,200Y/7620V. The 12.47 kV bus voltage is regulated with three single phase 333 kVA step type voltage regulators connected to the secondary bushings of the transformer. MWL has wireless communication with the distribution breaker, which allows remote operation and alarm notification. Transmission breakers have fault location and fiber connected communications for data monitoring only.

Substation #3 has a high degree of distributed generation interconnected. With the recent interconnection of the 2.2 MW Hess solar array the substation has approximately 5.0 MW (a.c. nominal capacity) of solar generation interconnected. The recent PLM study recommends that MWL should replace the oil circuit breakers at Substation #3 and will be installed no later than 2024.

Figure 26: MWL's Substation #3

Substation #5:

Substation #5 is located within a quarter of a mile of the commercial and industrial load center of Morristown making it ideally suited to serve distribution load in the northern and central portions of MWL's service territory. The substation includes a 34.5 kV, 3.6 MVAr shunt capacitor bank that is used for power factor correction and voltage support on the 34.5 kV sub transmission system. The capacitor bank substation rack has provisions to add more capacitors, as-needed, to provide further reactive power compensation or voltage support. The station serves distribution customers via three 12.47 kV feeder positions; 5.1, 5.3, and 5.4. A fourth feeder at this station, 5.2, is run express to the adjacent Trombley Hill solar array. The three load serving feeders supply customers in the Garfield section of Hyde Park, Elmore, and all of the commercial load on the north end of town. All of the feeder reclosers are Eaton NOVA15 type with form 5 controls. The substation transformer is a 55/65°C unit with an ONAN (natural convection cooling) rating of 7.5/9.375 MVA and an ONAF (with fans on) rating of 8.4/10.5 MVA. The transformer has a nominal voltage of 34,400-13,200Y/7620V. The 12.47 kV bus voltage is regulated with three single phase 333 kVA step type voltage regulators connected to the secondary bushings of the transformer.

Around the year 2030-2031, the recent PLM study recommends that MWL relocate the #619 recloser from Substation #6 to Substation #5. In addition, PLM recommends that MWL install a second 34.5 kV recloser at Substation #5 to completely mitigate single contingency line exposure for all Substation #5 customers.

Figure 27: MWL's Substation #5

Substation #6:

Substation #6 is a switching station and includes two 34.5 kV breakers. One breaker provides protection to the 3319 Line for faults between Substation #6 and Substation #7 at the Green River Plant. The second breaker (619) was installed to segment the 3319 line from Substation #3 to Marshfield. For a fault on the line between Substation #6 to Marshfield, the breaker will protect the MWL section, keeping Substation #5 from tripping off. The 619 breaker is an ABB OVR 3 phase vacuum breaker installed with an ABB control panel. Breaker 619 has remote reading ability to notify personnel of an operation. VELCO has a fiber interconnection at Substation #6 which presently monitors the 619 breaker status. Substation #6 does not have remote SCADA control.

Figure 28: MWL's Substation #6

Substation #7:

Substation #7 is a step-up station for the Green River hydro generation. The plant output voltage is 4,160 volts. The plant output is stepped up to 34.5 kV through 3-833 kVA transformers connected delta on the low side and grounded wye on the high side. Substation #7 interconnects to Substation #6 with a 34.5 kV line.

The recent PLM study recommends that MWL rebuild Substation #7 within the next 5-10 years.

Figure 29: MWL's Substation #7

Johnson Substations (3):

There are three small step-down substations located in the Town of Johnson. These substations were built to supply a small number of customers when the Villages of Johnson and Hyde Park and the Vermont Electric Cooperative had not yet served the area. The MWL 34.5 kV line serving the Johnson talc mill and talc mine was the closest source of electric power. The step-down substations consist of a two 100 kVA and one 50 kVA, 34.5-7.2 kV (single phase) transformer and a regulator mounted on pole-mounted platforms.

Pratt & Reid Substation:

Pratt and Reid Substation is currently not activated. It was originally a customer-owned substation. MWL purchased the substation in 2002, when the customer's load dropped off significantly, and was able to serve distribution load to the west of Brooklyn Street when needed. The substation consisted of a 2,000 kVA, 34.5-12.5 kV transformer and one 12.5 kV distribution circuit. Its proximity to the new commercial center of MWL makes it a strong asset to the MWL system; it being close to Substation #5 gives it the capability to provide significant backup to that substation. MWL's long-term electrical infrastructure plan is to re-energize the Pratt & Reid Substation in conjunction with Substations #3 and #5 to serve MWL's load for the foreseeable future.

Around the 2032-2033 timeframe, the PLM study recommends that MWL rebuild the Pratt & Pead Substation. The rebuild would include installation of a new power transformer, oil containment, 15 kV regulators, and a15 kV recloser.

CIRCUIT DESCRIPTION:

Table 20: MWL Circuit Description

Circuit Name	Description	Length [1](Miles)	# Customers by Circuit
5.4	Morrisville & Elmore	11.4	1,509
5.1	Hyde Park & Wolcott	7.4	432
3.1	Morristown & Stowe	13.3	887
3.2	Morristown & Stowe	9.5	1,007
5.3	Morrisville No. End and Cady's Falls	2.7	317
10	East Johnson	2.3	24
11	Collins Hill	1.2	48
12	Tomlinsons	0.47	23
5.2	Trombley Solar	0.1	n/a

[1] Estimated from circuit maps

There are 9 circuits in total. The voltage of the circuits is regulated at the substation bus. MWL does not consider any of its circuits to be particularly long. MWL operates its system to maintain 114 to 126 volts at the customer's outlets.

T&D SYSTEM EVALUATION

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

Outage Statistics

MWL evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. The evaluations include the review of the Public Utility Commission Rule 4.900 Outage Reports and data collected from load loggers. In addition, MWL periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. MWL's last T&D study was completed in January 2023. The cost of the improvements recommended in the study are developed into a 5-year budget and approved by the Trustees based upon the financial position of MWL's electric department.

Tree contact from severe weather events is the primary cause of service interruptions from the distribution facilities. To prevent future outages and maintain reliability, MWL continues to trim trees. In addition, MWL has wrapped up its voltage conversion work in order to connect and complete a tie between Substation #3 and #5 to avoid large number of customers out of service due to emergency or scheduled outages, particularly related to the loss of a substation transformer at either Substation #3 or #5. MWL strives to complete trimming of its entire system on a 8 to 10-year rotation. This target was recently upgraded by the Trustees to improve reliability and be responsive to harsher storms and more rapidly growing vegetation. MWL also takes out danger trees as necessary subject to landowner approval.

MWL's Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years in their entirety, can be found in Appendix C, at the end of this document.

MWL has committed to performance standards for reliability that measure the frequency and duration of outages affecting its customers. There are two primary measures for the frequency and duration of outages. The Public Utility Commission's Rule 4.900 defines them as:

> System Average Interruption Frequency Index (SAIFI): Customers Out, divided by Customers Served. SAIFI is a measure of the average number of times that the average customer experienced an Outage.
>
> Customer Average Interruption Duration Index (CAIDI): Customer Hours Out, divided by Customers Out. CAIDI is a measure of the average length of time, in hours, that was required to restore service to customers who experienced an Outage.

MWL has committed to achieving performance levels for its distribution system below an index of 3.0 for SAIFI and 2.5 for CAIDI. MWL maintains a record of and reports on all its system outages, including the root cause of an outage. While some outages cannot be prevented, there are a number of specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

The following table summarizes MWL's SAIFI and CAIDI values for the years 2018 – 2022.

Table 21: MWL Outage Statistics[14]

	Goals	2018	2019	2020	2021	2022
SAIFI	**3.0**	1.4	2.5	1.1	1.7	1.6
CAIDI	**2.5**	2.3	1.7	2.7	1.4	0.8

[14] SAIFI and CAIDI statistics shown are net of major storm outages

MWL has a number of initiatives underway to improve reliability. Each of these initiatives is described below.

Animal Guards

MWL has very few animal contact events a year. In addition, MWL has changed out a number of porcelain cutouts and took the opportunity to install animal guards in the early 2020's.

Fault Indicators

MWL does not currently use fault locators on its distribution circuits since its circuits are relatively short and accessible. MWL uses its outage management system, fuse location, dispatching and line crew knowledge of the system for locating faults. In the future, (estimated to be 2024 to 2025), AMI infrastructure will work in conjunction with the outage management system to improve our fault indication.

Automatic reclosers/Fusing

MWL has automatic reclosers installed on most of its distribution feeders. The exceptions are East Johnson, Tomlinson and Collins Hill. Reclosers attempt to maintain service to the maximum extent possible for momentary interruptions caused by tree and animal contacts on the main line. In addition, MWL fuses all of the tap lines off of the main distribution line to reduce the number of customers impacted by faults on the tap lines. MWL has two remote operated motorized switches to provide loop feeds. MWL has not completed a total system fuse coordination study. No study is presently contemplated since MWL is not getting any indications that it is having coordination issues. Fuse coordination issues are minimal. Line workers have extensive experience with fusing the system and have successfully fused the system using industry rules of thumb. Fuse size adjustments are made if a fuse mis-coordination occurs.

Feeder back-up

Presently, MWL has significant feeder back-up capabilities due to the completion of its multi-year conversion to one primary voltage for all distribution to 12.47 KV and ability to service customers from multiple, interconnected substations.

There is now a 12.5 kV tie between Substation #3 and Substation #5. While this tie allows either substation to carry the load of the other, the exposure to the hospital is high. Going forward, it is anticipated that additional ties will be constructed which will allow greater flexibility in providing back-up capability.

MWL does not have many supplier-associated outages due to the three transmission sources to its system. MWL's load can be served from any two of the three sources 100% of the time and can be served entirely from either the Stowe or Johnson source alone for over 95% of the time. In addition, the distribution transformer at Substation #3 is located on a 35 kV bus such that it does not drop out for line faults.

Power Factor Measurement and Correction

MWL lacks the equipment needed to accurately measure power factor at various locations on its system. MWL is investigating the cost of options with other VPPSA members to collect the data required to establish a program to improve its annual system power factor to 95%. This power factor value came from a model used for conducting distribution studies in the past and reflects a typical value based upon the consultant's experience from studies completed for other systems that had measured power factor.

Although MWL's summer power factor approaches the 95% target, its winter power factor is estimated to be near unity with the 3.6 MVAR substation capacitor bank in service at its Substation #5. This bank is in service year-round for 34.5 kV voltage support and power factor correction based upon automatic voltage control. MWL's hydro plants also provide power factor correction and volt amp reactive support when they are generating power.

A long-term planning study was completed for MWL's distribution system in 2022. The planning study summarized the normal operating parameters of the distribution system. No parameter violations were identified.

Longer term, PLM recommends that MWL install more 12.47 kV capacitors and consider eliminating the 3.6 MVAR substation capacitor bank. PLM agrees with a prior consultant that five additional capacitor banks should be installed on the distribution system in order to bring the power factor during summer peak conditions closer to unity. Ordering units with vacuum switches and digital controllers (even if they will be always on) will provide MWL with more flexibility to adjust power factor correction strategies as system loads change. Installation of equipment to monitor existing real and reactive power demand at various points is a logical first step.

MWL relies on VELCO for completing load flow studies of the sub-transmission system (34.5 kV). The addition of the 115 kV substation in Stowe has significantly improved the normal and contingency performance for the Lamoille County utilities.

Other

Vegetation management and relocating country lines to roadside are also two important initiatives which MWL uses in order to improve reliability. Both will be discussed in greater detail later in this document. The lack of clear right of way / easement ownership also creates difficulty in maintaining the system. MWL has begun planning to rectify this shortcoming. Additionally, MWL is in early stages of investigating and understanding the economics of installing spacer cable with tree wire as a means of economically improving reliability in areas on the system that have historically been problematic with tree outages and where other solutions will be costly. MWL anticipates determining the efficacy of this solution as well as target areas for deployment in 2024.

Distribution Circuit Configuration

Voltage Upgrades

In 2021, MWL added 5 capacitor banks to the system to assist with voltage issues. Regulators at substation 3 were upgraded during the upgrade of the station in 2021.

Phase balancing

MWL's loads are fairly stable and do not generally require reconfiguration to balance the load. Load data for each phase of each feeder is collected via recloser control panel data and reviewed periodically in order to check balance. This has been particularly important during the conversion work as major changes are being made to the paths power as delivered across the distribution facilities. Any additional load growth is connected to maintain load balance. Phase currents that are generally within 5% of each other are considered balanced.

As stated earlier, MWL has positioned itself for improving its feeder back-up capabilities as the conversion work has been completed. The voltage conversion work was completed in 2018, along with the updates of the system maps Reconductoring projects were also completed in recent years to create multiple loops for alternate supply to minimize the number of customers impacted while repairs are made.

The recent PLM study recommends that MWL monitor feeder loading for feeder positions 3.1, 3.2, and 5.4. The study recommends MWL also perform phase balancing by transferring the single-phase taps as required to minimize imbalance.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

Protection Philosophy

MWL's system protection includes sub-transmission (34.5 kV), substation and distribution protection. Each is discussed briefly below.

34.5 kV Sub-transmission Protection:

The protection of MWL 34.5 kV system is shared with GMP and VELCO. There are three main line sections from MWL #3 Substation. These include the 3319 line to Hardwick/Marshfield, the 3329 line to the VELCO Substation in Stowe and the B22 line to GMP's substation in Johnson. These lines have breakers on both ends for fault protection. The status of the GMP and MWL's breakers is monitored via SCADA. The status of the GMP breaker is monitored by GMP's SCADA. GMP is also able to operate its breakers via SCADA. MWL's breakers at Substation #3 are not operable via SCADA. Any abnormal operation of the protection system is reviewed by VELCO, GMP and MWL and relay settings are modified if required.

Substation Protection:

The substation equipment is protected by a combination of high side fuses and breakers. MWL does not have any bus differential protection at its substations at this time. MWL has not tested substation equipment for the past 10 years, opting instead to focus on replacement of old equipment.

In 2022 report, PLM recommended that MWL develop an annual maintenance program for substations which MWL fully concurs with.

Distribution Protection:

The distribution system protection involves a combination of distribution circuit reclosers for each feeder and fuses. All side taps of the main line distribution feed are fused.

MWL had an arc flash analysis completed in 2014; that analysis included data on all relay and breaker settings. A fuse coordination was not done at that time. The recent

PLM study recommends MWL perform an arc flash hazard study. Since MWL has not had such an evaluation completed for several years and in that time significant system improvements have been made including reconstruction of the Substation #3 12.47 kV section, installation of numerous large scale solar arrays, and feeder relay setting changes, an arc flash study is recommended to protect MWL's workers. PLM also recommends that MWL do another arc flash study 5-year update around 2027 after the first one is completed in '22/'23 timeframe.

SMART GRID INITIATIVES

EXISTING SMART GRID

MWL has installed 180 smart meters as a pilot program and expects to install electric AMI systems in 2024.

PLANNED AMI

Beginning in 2018, MWL 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. Further details can be found in Appendices D, E, and F regarding the AMI RFI, RFP, and the general decision-making process.

This process resulted in VPPSA entering a contract with Aclara to provide AMI services to its members, including MWL. MWL has entered a contract with VPPSA to formally become part of the implementation cohort for AMI with our anticipated installation date being 2024.

Aclara's 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.

MWL 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
- Enhance information flow with customers related to outage management in conjunction with our OMS
- Improve access to outage information and management by our line crews in the field in conjunction with our OMS
- 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
- Gain access to voltage reporting thru the system
- 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 of more than $969,000, with a positive cost-benefit ratio of 1.52 and a 6.3-year payback, providing MWL with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of the state funding opportunity. The final contract with Aclara has been recently signed and MWL is optimistic that it will begin implementation of a new AMI system in either late 2024 or early 2025, to be completed no later than the end of 2025.

GEOGRAPHIC INFORMATION SYSTEM

MWL, working closely with VPPSA, has invested heavily in GIS/Outage Management Systems. Over the past five to ten years our electric system has been fully mapped with deep integration with our OMS, MPower. Recently, MWL further enhanced its capabilities to keep information current by investing both in GPS location device (Trimble) and the acquisition of tablets to enable crews to pull up information real time in the line trucks.

These investments enable our line crew to have full system information in the field, greatly enhancing safety and operational effectiveness. In outage conditions, crews are able to understand where problems exist and to clear outages right in the field enabling quicker closing of outages and more effective movement to the next issue. In normal operations, crews use information to more quickly ascertain where reclosers and such equipment are as they pre-stage the work for the day. For customers, these investments will enable MWL to bring real-time outage information online as soon as AMI is deployed and tested (likely 2025). For management, these tools assist in proper planning of projects, understanding of routing options to move cross-country lines back to the road, and many other analytic assessments.

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

MWL 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. MWL conducts ongoing vulnerability assessments and MWL recently completed its most current assessment. MWL now has a roadmap for necessary investments for implementation and budgeting for upcoming years and plans to, with support from VPPSA, budget improvements beginning in 2024.

OTHER SYSTEM MAINTENANCE AND OPERATION

RECONDUCTORING FOR LOSS REDUCTION

MWL gradually replaced small conductor over the last twenty years and completed this program in 2017. The conductor was replaced to avoid bottlenecks from backing up Substation #3 with Substation #5 and vice versa. Current day growth and needs require continued upgrades moving forward.

The PLM study recommend that MWL transfer Industrial Park Dr to feeder 5.4 to reduce losses via existing switching points on Harrel St. Install additional switching points with solid blades and cutouts to facilitate transfers between Substation #3 and #5 feeders.

TRANSFORMER ACQUISITION

Historically, MWL has purchased used transformers at a fraction of the cost of new transformers. MWL does not currently use an economic model to evaluate the life cycle cost of low loss transformers since the cost of used transformers always results in the lowest life cycle costs. The transformer supplier does provide loss data for the transformers purchased. MWL will consider using a spreadsheet-based tool in the future, developed in collaboration with the Department of Public Service to select lowest life-cycle cost equipment. In its recent PLM study, PLM recommends that MWL update or create distribution transformer specification to be used for procurement of new distribution pole mount and pad mount transformers.

CONSERVATION VOLTAGE REGULATION

All circuits are bus regulated at the substation. All reports of low voltage are investigated. No voltage complaints have been reported since the upgrade was completed at Substation #5. This substation has the largest circuit distance. Bus regulation is set to deliver 117 to 126 volts.

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

The recent PLM study recommends that MWL update voltage regulator settings per Section 10 of the study results. Also in the PLM study, PLM recommends that MWL procure and install one 38.1 kVA voltage regulator at Substation #11 to replace the failed unit. Also recommended is to procure and install three 114.3 kVA voltage regulators on VT-12, Elmore Rd.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

MWL does not have a DTLM program. MWL plans to pursue a DTLM program after smart meters are installed.

SUBSTATIONS WITHIN THE 100 AND 500 YEAR FLOOD PLAINS

MWL currently has three substations that fall within the 100-year and 500-year flood plains. Those substations are: Substation #1, Substation #2, and Substation #3. Substation #1 is located at the Cady's Falls hydro plant. Substation #2 is located at the Morrisville Hydro plant. Substation #3 located at Morristown Corners. Morrisville's goal is to be able to serve its customer load from either Substation #3 or Substation #5. Sub #1 and #2 distribution customers were removed to reduce risk of reliability issues. Further, substations were modified to be a step transformer for the hydro plants only. At plant #2 the pad mount location was moved to decrease exposure to high water. In case of the flooding of Substation #3, switching would be done to isolate the flooded equipment and feeder ties would be closed to restore customer load from Substation #5.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

The majority of MWL's lines are overhead lines. As the quantity of MWL's underground lines increase, MWL will become increasingly more involved with the Damage

Prevention Plan. MWL requires inspection of all underground lines prior to burial. This is performed by MWL employees.

MWL participates in Dig Safe and responds with line personnel to mark all utility owned underground lines. All primary underground is installed per MWL's specifications. MWL pulls all wire with its line crews. All underground is located on MWL's Outage Management System/GIS and gets updated as needed.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

When replacing transmission and distribution equipment, MWL adheres to its procurement policy adopted in 2023. This policy requires differing levels of quotation or bidding based on the scale of purchase. MWL installs equipment that has proven to be effective or reliable based upon experience. These purchases are based on pricing and reliability. Equipment purchases are evaluated based upon actual experience of MWL staff and the experience of other utilities in Vermont.

MAINTAINING OPTIMAL T&D EFFICIENCY

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

SYSTEM MAINTENANCE:

System maintenance includes a number of components. Each is discussed briefly below. MWL plans to draft and implement a system maintenance plan in 2023.

SUBSTATION MAINTENANCE:

MWL has an unwritten substation maintenance program. MWL performs annual oil checks on transformers, and monthly substation inspections. MWL currently only does a visual check of transformer oil levels. There has been a lapse in testing oil. Meter readers and line crews report maintenance issues as they find them in the field. Much of MWL's substation and distribution system has been upgraded in recent years and is in the beginnings of its scheduled maintenance. The recent PLM study recommends that MWL establish required testing, inspection, and other maintenance activity scope and frequency for MWL substations and that MWL identify qualified testing firms for completing this scope of work and obtain pricing.

Figure 30 MWL Substation Maintenance Checklist

Substation Monthly Check List		Date:			Ambient Temp:		Checked By:				
Sub #3	Battery Volts										
	High	Low	Counter								
					A PH Amps		B PH Amps		C PH Amps		
					Instaneous	Demand	Instaneous	Demand	Instaneous	Demand	
Breaker 3.1											
Breaker 3.2											
					KW		KW		KW		
					Instaneous	Demand	Instaneous	Demand	Instaneous	Demand	
Breaker 3.1											
Breaker 3.2											

				Oil Level	Winding	Liquid	Pressure	Fans	Buck	Boost	Neutral
Reg 1				L / M / H							
Reg 2				L / M / H							
Reg 3				L / M / H							
34.5 Transformer				L / M / H		N / L		On / Off			
DC Controller											
Betta Alams	Y / N	If Yes, see back side.									
B22							Drained	Running	Water	Oil Level	Heaters
3319					3319 Compressor						
3329					3329 Compressor						
3310											
	Last Change Date		Next Change Date								
Eye Wash Station					Last Test Date		Charged %				
Fire Extinguisher											
Notes:											

Sub #5	Battery Volts				Temp:					
	High	Low	Counter		A PH Amps		B PH Amps		C PH Amps	
					Instaneous	Demand	Instaneous	Demand	Instaneous	Demand
Breaker 1										
Breaker 2										
Breaker 3										
Breaker 4										
					KW		KW		KW	
					Instaneous	Demand	Instaneous	Demand	Instaneous	Demand
Breaker 1										
Breaker 2										
Breaker 3										
Breaker 4										

34.5 Trans.								On / Off	Buck	Boost	Neutral
				Oil Level	Winding	Liquid	Pressure	Fans			
Reg 1				L / M / H							
Reg 2				L / M / H							
Reg 3				L / M / H							
	Status										
Cap Bank:		Notes:									

Sub #6	Battery Volts		
	High	Low	Counter
622			
619			
Notes:			

Sub #7						
	Spot check					
Notes:						

Sub #10	Counter	Buck	Boost	Neutral	
					Notes:

Sub #12	Counter	Buck	Boost	Neutral	
					Notes:

Pratt Reed	Spot check
Notes:	

Sub #11	Spot check
Notes:	

POLE INSPECTION:

In 2023 MWL initiated a pole inspection initiative for its transmission and distribution poles. In recent history, distribution poles have been replaced due to voltage conversion, roadside relocation or re-conductoring projects. MWL has a goal to replace 50 transmission and distribution poles annually, growing the initiative to 85 per year over time. Approximately 10% of all poles are to be inspected annually, by line crew personnel. Transmission poles will be prioritized, for obvious reasons, where they are in the most need of attention. MWL has completed the mapping of its entire system.

The recent PLM study recommended that MWL should survey 10% of its existing pole plant each year (with all poles inspected at ten-year intervals) and budget to replace about 85 poles each year. Replacements will be prioritized by age, condition, and/or clearances. This will ensure that all poles are replaced before reaching their typical service life age of 60 years. MWL's poles are numbered sequentially as they are installed which makes it easier to identify the oldest poles.

EQUIPMENT MAINTENANCE:

MWL does not have a written maintenance program for its substation transformers, line breakers, switches, or protective relays. MWL has aggressively replaced porcelain cutouts with polymer cutouts system wide. It is MWL's intent to implement a written maintenance plan no later than 2025 taking into consideration the maintenance recommendations of the recent PLM study

SYSTEM LOSSES:

MWL is committed to providing efficient electric service to its customers. MWL's plan for improving system efficiency involves two actions. The first action involves monitoring actual system losses. The second action is to complete projects to reduce system losses. Each of these tasks is discussed briefly below.

Actual System Losses:

MWL monitors system energy losses by tracking metered system load at its interconnections to GMP, VELCO and Hardwick and comparing it to metered energy sales to its customers. The calculation is done on a rolling 12-month basis to minimize the impact of unbilled energy resulting from meter reading cycles not corresponding with the system load meters that run from the first to the last hour of the month.

Efforts to Reduce Losses:

MWL's primary effort to reduce line losses is increasing distribution system voltages, re-conductoring and reducing power flows on the 34.5 kV system. Each of these efforts is discussed in more detail below along with other miscellaneous topics. MWL was expecting to reduce losses into the 6% to 8% range by converting its distribution voltage to 12.47 kV. MWL cannot separate distribution and transmission losses.

Transmission Losses:

MWL has an issue involving real line losses associated with incremental power flows beyond what is required for MWL across MWL's system.

MWL is looking to either reduce the losses by opening the B-22 line or be compensated for the losses by others (GMP). The study completed by VELCO shows the B-22 line is critical and needs to be kept in the closed mode.

RELOCATING CROSS-COUNTRY LINES TO ROAD-SIDE

MWL evaluates the opportunity during line rebuilds to relocate cross-country lines to roadside. With system mapping complete, remaining cross-country line sections will be considered as future line rebuilds are approved in the budget.

DISTRIBUTED GENERATION IMPACT:

MWL presently has 134 residential scale (< 15 kW) net metered customers with a total installed capacity of about 1,054 kW. In addition, there are 16 customers who have arrays between 15 and 150 kW, with an installed capacity amount of 1,134 kW. Finally, one customer has a 500 kW system. This totals to 151 net metered systems on the MWL system totaling 2,688 kW.

INTERCONNECTION OF DISTRIBUTED GENERATION

MWL recognizes the unique challenges brought on by increasing penetration levels of distributed generation. MWL 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 MWL 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, MWL will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow MWL 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). MWL continues to monitor trends for interconnection protection for abnormal conditions. Supplementing the process outlined in Rule 5.500 with detailed recordkeeping and periodic reviews of how much distributed generation is installed by feeder will help member utilities identify these types of issues before they occur. Our current expectation is that the combination of the addition of AMI meters, working in conjunction with our OMS system (MPower) will enable us to run voltage reports on every line of interest in our system. Once installed, we'll assess how well this works and look to further improve the system (as and if necessary).

INVERTER REQUIREMENTS

Consistent with ISO New England requirements related to inverter "ride-through" settings, MWL 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. MWL recognizes the need to standardize efforts aimed at certifying inverter compliance with the ISO SRD and will work with VPPSA and the PSD to achieve use of common forms and process in this regard.

DISTRIBUTION-LEVEL IMPACT OF ELECTRIFICATION

MWL 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 expected to increase. In the short term, MWL is focused on the challenge of identifying and tracking "hot spots" on the system as they develop, with an eye toward formulating timely responses, whether those be load management efforts, equipment upgrades, or addition of generation/storage at key locations.

The MWL distribution system currently has sufficient capacity for the immediate foreseeable future. Table 22 indicates, MWL has a large number of small solar projects on its system along with one large 500 kW unit. Maximum loading on Substation #3 transformer is currently about 36% of its nameplate capacity and about 23% on average. Substation #5 shows maximum loading of 46% of nameplate capacity and average loading of 29%. Substations #10, #11, and #12 currently show maximum loading of 39%, 12%, and 37% respectively, and average loading of 22%, 8%, and 22% of nameplate, respectively.

Table 22: MWL Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity (MVA)	Peak % of Nameplate (2)	Avg Load % of Nameplate (1)	CIRCUIT/ FEEDER	Circuit Voltage (kV)	Dist. Generation # of Units	Nameplate AC Output Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
Substation #3	1	10.5	20%	13%	3.1	12.5 kV	34	2,554		-	-
			16%	10%	3.2	12.5 kV	45	2,670		626	325,560
			36%	23%	SUB 3 TOTAL	12.5 kV	79	5,224	-	626	325,560
Substation #5	1	10.5	12%	8%	5.1	12.5 kV	9	382		365	78,443
			0%	0%	5.2	12.5 kV	1	855		-	-
			13%	8%	5.3	12.5 kV	7	573		690	294,640
			21%	13%	5.4	12.5 kV	36	328		526	246,800
			46%	29%	SUB 5 TOTAL	12.5 kV	53	2,138	-	1,581	619,883
Substation #10	1	0.1	39%	22%	10.1	7.2 kV (1PH)				-	-
Substation #11	1	0.5	12%	8%	11.1	7.2 kV (1PH)				-	-
Substation #12	1	0.1	37%	22%	12.1	7.2 kV (1PH)				-	-

(1) Estimated Annual kWh / (transformer capacity * 8760)

(2) Estimated Peaks by Circuit are Derived from Connected kVA on each Feeder

With the projected large-scale increase in peak energy projected by ITRON in the full electrification scenario, MWL hired PLM to assess whether our current infrastructure will be capable of serving reliability under those loads or if upgrades will be necessary. This analysis is projected to be available at the end of 2023 and will result in updated capital plans at MWL.

While the anticipated current pressure point is at the service drop level, the upstream distribution system is adequate for the near future; electrification impacts have yet to become a critical issue at the substation level. In recognition of the potential stress on its system, MWL is exploring sources of data readily available in the short term, that will help identify locational trends, facilitate early identification of and inform proactive responses to developing concentrations of electrification-driven load.

At the present time, MWL tracks customer adoption of electrification measures based on data captured from past and current incentive programs. This incentive-program driven dataset provides a significant amount of information regarding the magnitude and approximate locational trends of electrification driven load. MWL is able to track installed electrification measures associated with incentive programs, by street address, within the MWL system. Use of this dataset in the short run assists the development and analysis of historic deployment patterns as well as anticipating penetration patterns. While this data currently shows a very limited level of penetration that is evenly scattered across the MWL system, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to MWL's responses to expected electrification impacts on its distribution system.

MWL anticipates that implementation AMI in the next couple years and the continued improvement of and integration with both GIS and OMS systems will provide the ability for implementation of more sophisticated, timely and location-targeted distribution system planning, rate driven load management responses, including load control programs where appropriate, and development of forward-looking distribution system improvements designed to take advantage of opportunities to encourage cost-efficient and balanced load growth. As the anticipated AMI and GIS implementations reach maturity, MWL will be in a position to systematically track and analyze transformer, circuit and substation loading on a locational basis and focus on exploiting the new system's abilities. The improved data availability and analytical capability will facilitate MWL's planning for appropriate distribution system development by enhancing MWL's ability to:

- Monitor physical limits at substation, circuit and transformer levels,
- Identify areas of growing load concentration,

- Discern apparent penetration and deployment patterns of electrification measures based on actual metered load information at the customer level.
- Identify developing spatial patterns of load growth that highlight opportunities to target distribution system upgrades that are cost effective, shape efficient system load growth, and further resiliency efforts.
- Develop effective strategies to implement appropriate load management programs including amount of and optimal location of storage facilities, innovate rate designs, and active load control/management programs.

VEGETATION MANAGEMENT/TREE TRIMMING

MWL has about 180 miles of distribution and 30 miles of transmission lines. It estimates about 20% of the lines run through fields that do not require tree trimming; the other 80% of the lines require tree trimming. MWL has a target to complete tree trimming for all of its distribution and transmission on an 8 to 10-year cycle. MWL uses local contractors and its own crews for performing trimming on its system. During the COVID-19 years, very little tree trimming was accomplished due to contracting challenges. In early 2023, a new vendor was hired to re-start the process, consistent with recommendations from the PLM system deficiency study. The following table summarizes the amount of line trimmed and the cost of the trimming over the past few years. While MWL has not conducted an analysis, it believes the combined use of the local contractors along with its own personnel provides a cost-effective approach to tree trimming.

MWL has a layer in its mapping system that shows where and when it trims. MWL's outage reports show tree contact being the primary cause of outages. MWL's outage reports show that the trimming plans need to be aggressively pursued.

All lines are trimmed to the edge of the legal right-of-way. The trimming width on either side of the line varies depending on the voltage and right-of-way easement.

In addition to its vegetative and brush management program, MWL has a program to identify danger trees within its rights-of-way and to either prune or remove those trees. Again, the success of this program is measured by whether danger trees are a root cause of system outages. Danger trees are identified by utility personnel while patrolling the lines, reading meters, or inspecting the system and our customers. Once a danger tree is identified, it is promptly removed if it is within MWL's right-of-way. For danger trees outside of the right-of-way, MWL contacts the property owner, explains the hazard, and, with the owner's permission, removes them. Where permission is not granted, MWL will periodically follow up with the property owner to attempt to obtain permission.

The data in the tables is a little misleading for trying to determine the trimming cycle. MWL experienced a number of major storms over the past five years that resulted in significant tree contact from trees toppling over into the rights-of-way. The cutting done for these storms is not reflected in the numbers. Going forward, absent disruptions of this type, MWL anticipates trimming approximately 15 miles per year. In addition, MWL's Trustee's made a commitment to maintaining and increasing the tree right of way clearing budget in 2023 through 2027 and beyond to improve reliability.

MWL's analysis of tree trimming expenses shows MWL is currently on a 12 - 14-year cycle with using outside contractors, when adjusting for the Covid years. Moving to an 8 - 10-year cycle is estimated to cost $250,000 to $300,000 per year compared to $130,000 per year spent for the last 4 years, roughly doubling the amount of dollars to be spent each year.

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

Table 23 MWL Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Transmission	Approximately 33 miles	20	10-year average cycle
Distribution	Approximately 180 miles	150	10-year average cycle

Table 24 MWL Vegetation Management Costs

	2020	2021	2022[15]	2023	2024	2025
Amount Budgeted	$193,000	$205,000	$235,000	$210,000	$230,000	$250,000
Amount Spent	$183,000	$159,000	$56,000	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	6 miles	6.3 miles	0 miles	15 miles to be trimmed	15 miles to be trimmed	15 miles to be trimmed

Table 25 MWL Tree Related Outages

	2018	2019	2020	2021	2022
Tree Related Outages	127	66	25	38	37
Total Outages	191	124	103	113	142
Tree-related outages as % of total	66%	53%	24%	34%	26%

STORM/EMERGENCY PROCEDURES

Like other Vermont municipal electric utilities, MWL is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows MWL to coordinate not only with public power systems in Vermont, but with those throughout New England. A MWL representative is also on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties. MWL uses the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. MWL believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. MWL partners with neighboring municipalities and cooperative when extra crew power is required. MWL does not typically use contract crews.

PREVIOUS AND PLANNED T&D STUDIES

FUSE COORDINATION STUDY

[15] The historical amount spent in 2022 is significantly lower than prior years due to MWL's contactor unexpectedly being unavailable to MWL. Therefore, the 2022 amount was spent on fixing ad hoc issues rather than on planned trimming.

Fuse size changes are made to up-stream fuses when fuse sizes are increased for load increases or other reasons. Historical data from voltage conversion work and system mapping from the outage management system have all been included to maintain fuse coordination.

SYSTEM PLANNING AND EFFICIENCY STUDIES

System Operation

The reliability of MWL's electric system has been greatly enhanced by the addition of the VELCO 115 kV substation in Stowe in 2009 served by the new 115 kV line extension from Middlesex. MWL relies on VELCO for evaluating electrical system configurations when MWL needs to take portions of its 34.5 kV lines out of service. In addition, MWL has given GMP authority for monitoring the condition of the 34.5 kV system and scheduled line outages on the MWL 34.5 kV lines are coordinated with GMP's dispatch center including the review of MWL's planned switching procedures.

Distribution System Planning

MWL commissioned a system planning study in 2022 with PLM Electric Power Engineering. The study period was 2022 to 2037. The study was completed in September 2022. MWL's Trustees approved the plan and MWL is currently implementing the recommendations.

The objective of this study was to analyze the MWL distribution system and provide a plan of system upgrades over the next fifteen years. To accomplish this goal, a 2022-2037 load forecast was developed. The results of this forecast were then used in the Aspen DistriView software, along with substation and line data, to model the entire MWL system. By using this model, present and future problems were identified. The model was then modified to reflect various system upgrades, which were then compared with respect to system performance, loss reduction and cost, to obtain the best overall plan.

At a top level there exists a few areas for investment for consideration:

- **Transmission and Distribution**: the study recommends investment in airbreak switches, pole top voltage regulators and fuse as key investments. It also recommends that MWL should increase its rate of pole replacements.
- **Substations**: Items such as voltage regulators, reclosers, animal guards, full substation rebuilds are recommended to assure the MWL system continues to operate reliably and safely.
- **Inspections and Studies**: An ark flash study, the creation of a standard operation procedure for substation maintenance, the creation of a transformer specification, and regular pole inspections are recommended so MWL remains safe, reliable and keeps up with new demands moving forward.
- **Annual Maintenance**: Performing annual maintenance on substations and vastly increasing the pace of the vegetation maintenance are recommendations from PLM.

The recommendations for 2022-2027 are summarized below in Table 26.

Table 26: MWL PLM Study Summary of Recommendations 2022-2037

Recommendation	**Total External Costs**	**Anticipated MWL Labor**	**Year**
Update voltage regulator settings at Substations	$0.00	1-day of General Foreman	2022
Load Rebalancing after Sub #3 Completion	$0.00	1-week of a Line Crew	2022
Replace the failed #502 airbreak switch, including installation of additional switching points to facilitate load transfer to Sub #3 during the work	$25,000.00	1-week of a Line Crew	2022
Install cellular modem for new feeder 3.2 and connect DAS	$1,000.00	1-day of General Foreman 2-days IT person	2022-2023
Develop Substation Maintenance Scope & Frequency	$7,500.00	Cost is Inclusive of internal labor	2022-2023
Transfer Industrial Park Dr to Feeder 5.4	$0.00	1/2 day of General	2022-2023
Arc Flash Hazard Study	$20,000.00	1-day of General Foreman	2022-2023
Update transformer specifications and develop loss evaluation factors	$5,000.00	1/2 day of General Foreman	2022-2023
Replace Substation #11 Voltage Regulator	$15,000.00	Cost is Inclusive of internal labor	2023
Install 3-114.3 kVA Pole Top Voltage Regulators on VT-12	$40,000.00	Cost is Inclusive of internal labor	2023
Replace 65 A fuses on VT-12 with pole top recloser	$40,000.00	1 day of General	2023
Procure a Spare for Hydro GSU Transformers	$90,000.00	Cost is Inclusive of internal labor	2023
Replace OCB's at Sub #3 with Substation Reclosers & External Line VT	$175,000.00	Cost is Inclusive of internal labor	2023
Investigate, procure, and install animal guard for 34.5 kV equipment at	$25,000.00	Cost is Inclusive of internal labor	2023-24
Rebuild Sub #7 w/ padmount and new recloser	$225,000.00	Cost is Inclusive of internal labor	2026-2027
Replace Sub #1 GSU fuse protection w/ 38kV recloser	$70,000.00	Cost is Inclusive of internal labor	2027
Replace Sub #2 GSU fuse protection w/ 38 kV recloser	$70,000.00	Cost is Inclusive of internal labor	2028
Install new 38 kV recloser at Sub 5, relocate 619 recloser, replace remaining Sub	$125,000.00	Cost is Inclusive of internal labor	2029-2030

Pratt & Read Rebuild (an option utilizing padmount option likely to be less expensive - work with MWL as we approach the date to determine design preferences)	$1,250,000.00	Cost is Inclusive of internal labor	2031-2032
Pole inspections (10% of plant annually)	$768,000.00	2-weeks of General Foreman to Review Report / Prioritize Replacements	2022-2037
Annual Pole Replacements (85 poles annually)	$2,550,000.00	Cost is Inclusive of internal labor	2022-2037
Annual Substation Maintenance	$300,000.00	Cost is Inclusive of internal labor	2022-2037
Cumulative Costs	$5,801,500	**Note:** Projects are listed for first ten years. Remaining 5 years is	
Average Annual Cost	$386,767		

Distribution System Planning Study based on Full Electrification Load scenario analyzed in this IRP.

In late April 2023, MWL commissioned another study, with PLM Electric Power Engineering, to evaluate the system with the assumption of the high electrification load case. The study is anticipated to be finished in late 2023.

Although the study is not complete yet, a high-level preliminary summary of anticipated projects that are forecast to be necessary to maintain reliability of the system, is shown below. These assumptions have been incorporated into the high electrification load scenario analyzed in this IRP and summarized in Figure 33.

Preliminary system improvement recommendations include:

1. Build out Pratt & Read to be another 10MVA size station with 3x 12.47 kV feeders.
2. Expand Sub #5 to add a second transformer and additional feeders.

3. Additional sectionalizing devices on the line with Sub#5 and Pratt & Read to prevent one line outage from taking out multiple station transformers.

The preliminary cost associated with such improvements is anticipated to be between $15M-$20M.

Transmission System Planning

MWL relies on VELCO for recommending improvements needed to the transmission facilities. In 2022, MWL and GMP completed a joint project to upgrade the 1.3 mile transmission line from Cady's Falls to Sub #3. Currently, MWL's focus on transmission planning includes significant upgrades to pole infrastructure.

MWL does not hold ownership interest in the transmission/distribution corridor that runs from Morrisville to Stowe, though it purchased rights in 1906, which purchases were not clearly identified as being for an easement or right of way. This lack of property access guarantee greatly impedes MWL in maintaining these critical T&D lines in more than a theoretical sense. MWL has been prohibited from access to our lines by owners and other owners declare we only may maintain but not fully repair or upgrade our systems. MWL has initiated a small first legal proceeding to fully attain access to certain poles that are approaching 80 years of age and which MWL believes will not likely survive the coming winter or two. Then, MWL intends to begin legal proceedings to assure necessary access along this entire corridor.

CAPITAL SPENDING

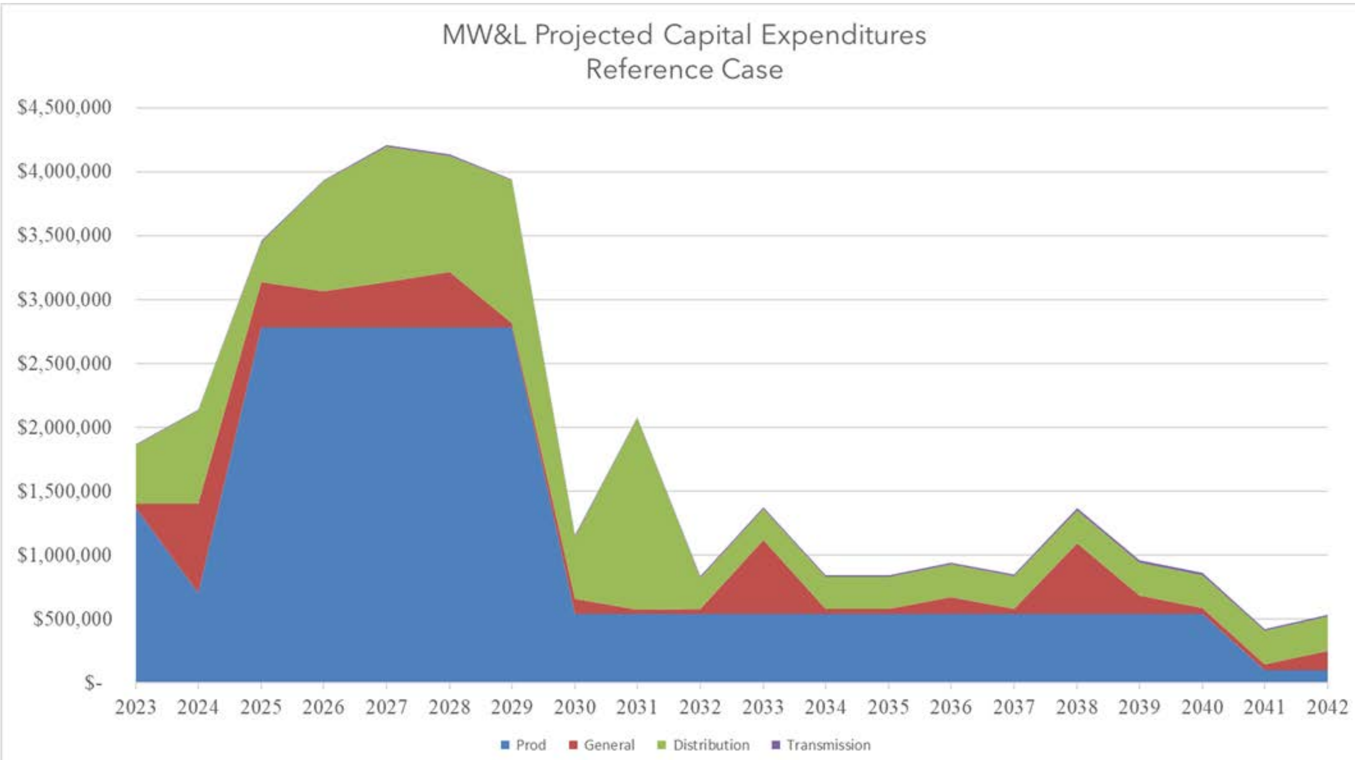
HISTORIC CONSTRUCTION COST (2020-2022)

Figure 31 MWL Historic Construction Cost

Village of Morrisville Water & Light Department		Historic Construction		
Historic Construction		2020	2021	2022
Functional Summary:				
Production		$ 277,878	$ 443,436	$ -
General		$ 43,397	$ 5,160	$ 8,747
Distribution		$ 162,889	$ 267,873	$ 1,346,166
Transmission		$ 47,401	$ 30,904	$ 89,057
Total Construction		**$ 531,565**	**$ 747,373**	**$ 1,443,970**

PROJECTED REFERENCE CASE CONSTRUCTION COSTS (2023-2042)

Figure 32 MWL Projected Reference Case Construction Cost



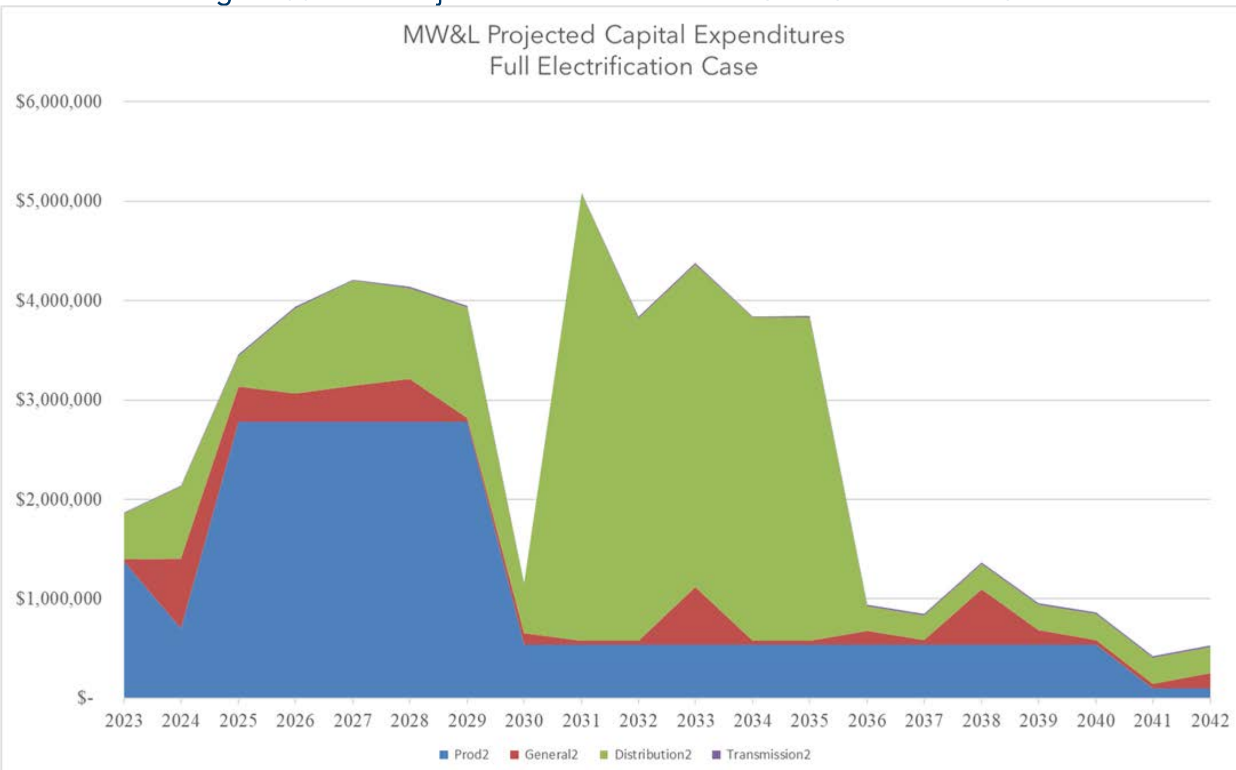
The main drivers of projected reference case construction costs are:

- $20 Million of hydro upgrades, front loaded in the 2023-2029 period.
- $5 Million of distribution upgrades identified in the 2022 PLM study including replacement of fuses with reclosers, new reclosers, replacement of regulators and a systematic annual pole replacement program.
- $0.5 Million for AMI implementation (est. 2024)
- $2.8 Million Investment supporting EV charging, SCADA, DERMS and other control systems.
- $5.6 Million financial, data, and cyber security systems; vehicles & misc. plant.

Additional details are shown in Appendix I.

PROJECTED FULL ELECTRIFICATION CASE CONSTRUCTION COSTS (2023-2042)

Figure 33 MWL Projected Full Electrification Case Construction Cost



Projected capital investment in the Full Electrification case includes investment from the reference case, which included addressing deficiencies surfaced in the 2022 PLM full distribution study, plus an additional $15 Million dollars of additional substation and feeder upgrades subsequently identified by PLM engineering on a high level, preliminary basis, based on the Full Electrification load forecast. This additional study addressing the distribution upgrades suggested by the Full Electrification load forecast is expected to be completed toward the end of 2023 or early 2024. The work envisioned includes enlarging or adding transformers to at least 2 existing substations, adding several feeders and sectionalizing certain line sections. This work is anticipated to occur in the 2031 to 2035 time period; the exact timing will ultimately depend on information contained in the final study result, on electrification adoption rates as they develop and other factors. Details of projected capital investment are shown in Appendix I.

OPERATING SYSTEMS

V. OPERATING SYSTEMS PLANS

Figure 34, below, shows MWL's operating system plans and important milestones from 2023-2030. The years depicted are rough estimates, therefore these events may occur slightly sooner or later than the years depicted.

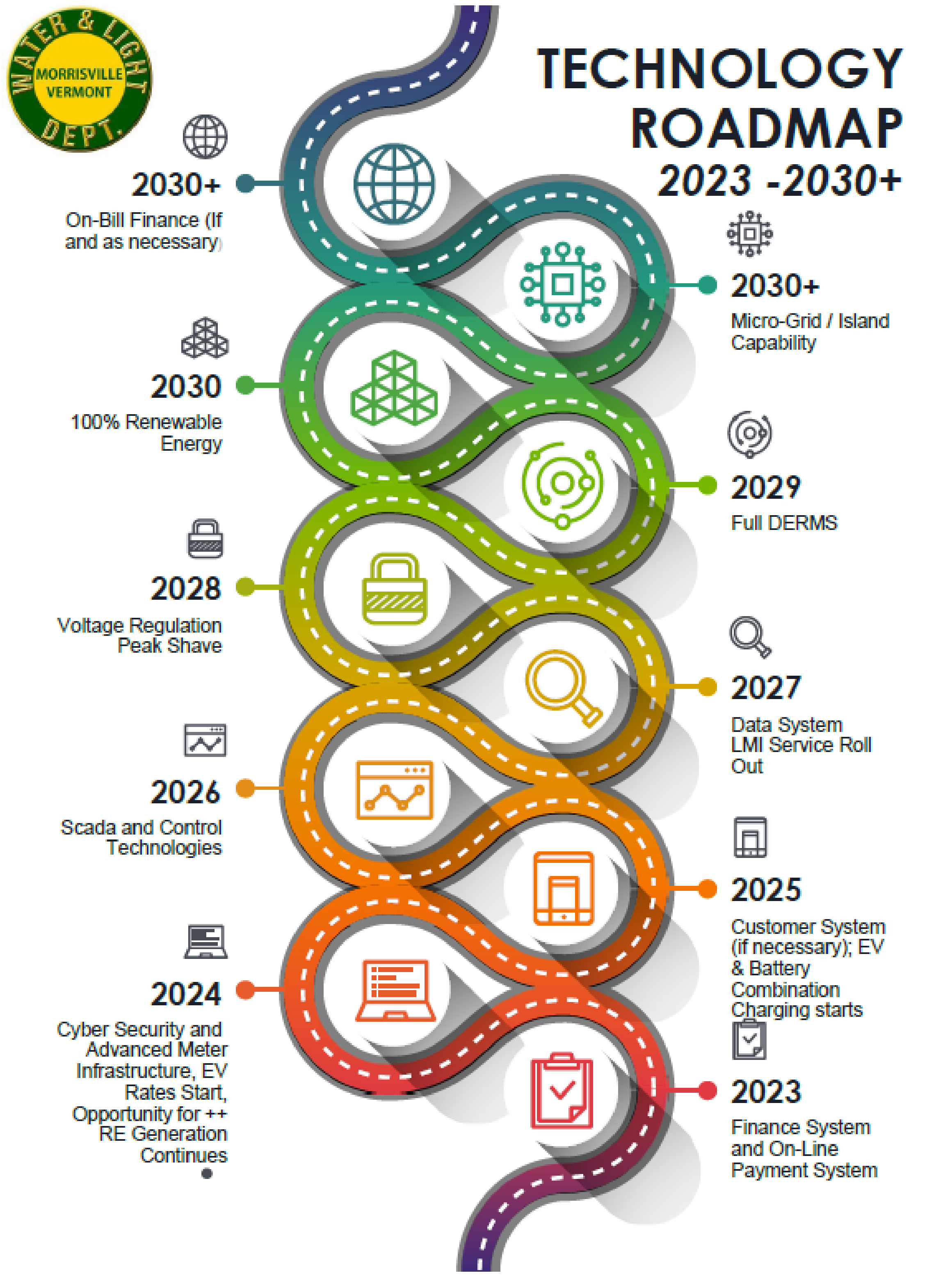
The technology roadmap includes everything from the battery storage to AMI, DERMS, cyber security, billing and finance solutions, customer programming capability, SCADA for grid management, a 2030 RES 100% renewability target date, and much more.

MWL is planning for a system of the future to allow for beneficial electrification and to allow for integration of more DERs while maintaining close to 100% reliability at least-cost. As customers rely on electricity to operate more aspects of their daily lives, reliability will become much more important.

As our electric system relies more and more on solar, wind energy, and DERs, each a variable, intermittent source, MWL will require the means to assure reliability to its customers. This will likely include, at a minimum, the following: enhanced local hydro generation, battery storage, Distributed Energy Resource Management (DERMS), energy efficiency.

Looking to the future, in addition to various T&D upgrades, MWL sees the need for varying sizes and locations of energy storage, coupled with technology/software upgrades to maintain a high degree of resilience and ensure customer satisfaction. In addition to the already planned AMI implementation and expansion of GIS capabilities, MWL will also need to make other technology advancements, such as modernized CIS/billing and financial systems and a Distributed Energy Resource Management System (DERMS) to allow for enhanced DER integration and overall grid management.

Figure 34: Technology Roadmap



FINANCIAL ANALYSIS

VI. FINANCIAL ANALYSIS

CUSTOMER FINANCIAL ANALYSIS

MWL's residential customers heat their homes with five different fuels, and the current price[16] of each one is shown in Table 27. The prices are converted to common units ($/MMBtu), and the far-right column compares the annual dollar cost using a typical residential customer's usage[17]. At today's prices, heating with a heat pump is by far the most cost-effective option, and the fuel cost savings would repay the cost of installing the heat pump well before the equipment reaches the end of its useful life.

Table 27: Heat Fuel Price Comparison for Residential Customers

Energy Source	Unit	Btu/Unit	Efficiency	$/Unit	$/MMBtu	$/Yr
Electric - Heat Pump	kWh	3,412	300%	$0.1678	$16	$1,475
Electric - Resistance	kWh	3,412	100%	$0.1678	$49	$4,425
Fuel Oil	Gallons	138,200	85%	$4.35	$37	$3,329
Pellets	Ton	16,400,000	85%	$400	$29	$2,582
Propane	Gallons	91,600	85%	$3.73	$48	$4,308
Wood	Cord	22,000,000	60%	$400	$30	$2,727

The economics for switching to electric vehicles from conventional gasoline vehicles are also favorable. The following table is based on 15,000 miles per year of driving, and even without tax incentives, the fuel savings are enough to make many EVs less expensive to own and operate than comparable ICE vehicles.[18]

Table 28: Electric Vehicle (EV) Fuel Cost Comparison to Internal Combustion Vehicles (ICE)

Energy Source	Unit	Btu/Unit	Efficiency	$/Unit	$/MMBtu	$/Year
Gasoline	Gallons	125,000	21%	$3.8000	$144.76	$2,280
Electricity	kWh	3,412	77%	$0.1678	$63.85	$805

[16] As of 10/8/23.

[17] Typical residential use is assumed at 90 MMBtu/year. Source: Comparative Analysis of Fuel Switching from Oil or Propane to Gas or Advanced Heat Pumps in Vermont Homes, Neme on behalf of VPIRG, 2015, page 2

[18] https://www.caranddriver.com/shopping-advice/a32494027/ev-vs-gas-cheaper-to-own/

One of the central questions for this IRP is, "Will the competitive advantage of using heat pumps and EVs hold up as electrification trends increase the cost of building and maintaining MWL's distribution system?" As the following sections will show, the answer appears to be, "Yes."

UTILITY FINANCIAL SCENARIOS

This section quantifies the costs of a Reference Case and a series of scenarios that would meet the RES 1.0 and RES 2.0 requirements as discussed in the Resource Plans chapter. It also includes the impact of full electrification on the RES 2.0 scenario as well as two storage scenarios. These two scenarios illustrate the cost saving potential of a single MW-scale, peak-shaving battery and the more fulsome storage build out that was described in the Resource Plans chapter. The characteristics of these scenarios are summarized in Table 29.

Table 29: Scenarios

#	Resource Scenario	New Resources	Term	Price
0	Reference Case	N/A	N/A	Monthly DALMP
1	RES 1.0 Requirements	Brookfield & Stetson PPA extensions	2028 - 2032	$75-$82/MWH Levelized
2	RES 2.0 Requirements	1.0 PPA Extensions + 4.5 MW New Solar in 2032	2032 - 2042	$110/MWH Levelized
2.1	RES 2.0 Req. + Full Electrification	None	N/A	N/A
3	Single Storage ESSA	4 MW, 12 MWH	2024 - 2042	$15/kW-Month Levelized
3.1	$40 M Storage Build Out	15 MW, 60 MWH	2025 - 2034	$18/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 and wind 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. The solar PPA is priced at $110/MWH, which is in alignment with VPPSA's recent solar PPA's. Finally, storage is priced at $15/kW-month, which is in alignment with the latest offers from VPPSA's storage partners.

UTILITY FINANCIAL ANALYSIS

Table 30 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and for the RES 1.0, RES 2.0, full electrification and storage scenarios. Notice that the PVRR increases by about $0.4 million dollars or 0.2% under the RES 1.0 requirements. This is due to the cost of levelizing the Brookfield and Stetson PPAs at today's market prices, and reflects a small premium over spot market prices. RES 2.0 requirements increase the PVRR by $6.2 million or 3.8%. 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.

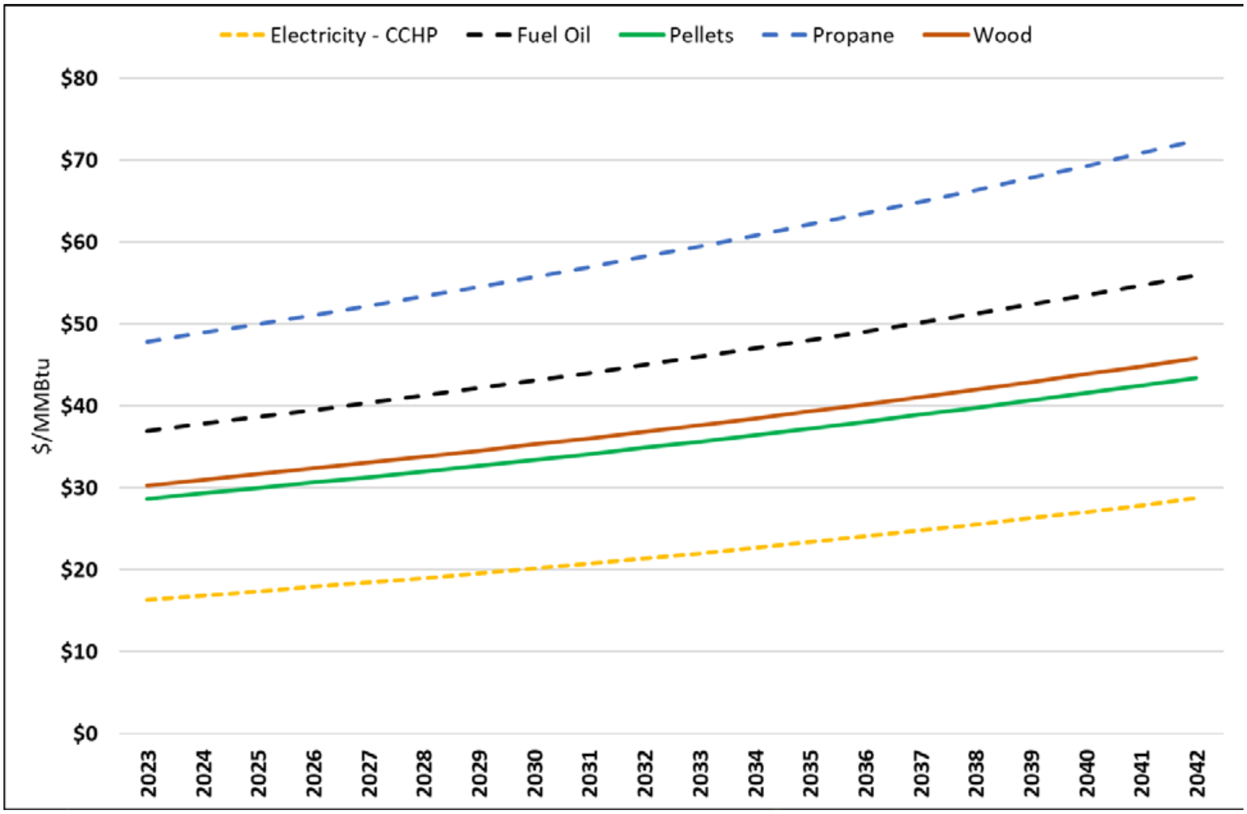
Table 30: Financial Outcomes of each Procurement Scenario

#	Procurement Scenario	PVRR ($ Million)	Unit	% Change
0	Reference Case	$162.3	PVRR (Million $)	N/A
1	RES 1.0 Requirements	$0.4	Chg. from Ref. Case	0.2%
2	RES 2.0 Requirements	$6.2	Chg. from Ref. Case	3.8%
2.1	RES 2.0 Req. + Full Electrification	$37.2	Chg. from RES 2.0 Req.	18.1%
3	Single Storage ESSA	-$2.1	Chg. from RES 2.0 Req.	-1.3%
3.1	$40 M Storage Build Out	-$5.2	Chg. from RES 2.0 Req.	-3.1%

The full electrification scenario increases costs by over $37 million, and the PVRR rises by 18.1%. However, the growth rate of the electric rate itself is only 3% per year. This is marginally higher than the 2.7% per year rate trajectory in the reference case. This outcome reflects the fact that electrification, and the increased retail sales that result from it, almost completely offset the increased capital costs that are necessary to support the load.

Importantly, this means that cost savings that customers can realize from switching to heat pumps remain favorable over the 20-year time horizon. Figure 28 shows the trends in these costs. The "Electricity – CCHP" trajectory begins with today's electric rate and grows at 3% per year, which matches the rate trajectory in the full electrification case. The other fuel prices grow at a more modest 2.2% per year, which matches the Energy Information Adminstration's Annual Energy Outlook for those fuels.

Figure 35: Heating Fuel Costs for Residential Customers Under Full Electrification



The conclusion for EVs is very similar. If gasoline prices continue to grow at 2.2% per year and electricity prices grow at 3% per year, then the fuel cost of EVs will remain less than half that of ICE vehicles in 2042

Figure 36: Vehcile Fuel Costs in 2042 Under Full Electrification

Energy Source	Unit	Btu/Unit	Efficiency	$/Unit	$/MMBtu	$/Year
Gasoline	Gallons	125,000	21%	$5.8722	$223.70	$3,523
Electricity	kWh	3,412	77%	$0.3031	$115.36	$1,455

SINGLE SITE – UTILITY SCALE STORAGE PROJECT

The other central question of this IRP concerns storage. Specifically, what are the economics of utility scale peak shaving storage projects, and what would a plausible storage build out look like under MWL's storage resource plan? This subsection quantifies the first question by summarizing the economics of utility scale peak shaving storage projects.

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 MWL'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 increased the cost of storage since the RFP was conducted. If MWL were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, the cost to MWL would be between \$720,000 and \$1,200,000 per year.

Figure 37: 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, 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 \$21/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 \$15/kW-month would be expected to reduce PVRR by \$2.1 million.

MULTI-SITE – MULIPLE SCALE STORAGE BUILDOUT

The storage resource plan envisions a scenario where storage is built at at multiple sites, at multiple scales, over multiple years. To assess the veracity of this strategy, we modeled a scenario where $40 million dollars is spent on storage in equal amounts over ten years. Using the National Renewable Energy Lab's Alternative Technology Baseline for commercial scale batteries, we determined that $4 million dollars per year would be sufficient to build about 1.5 MW of storage annually for ten years. The resulting build out would total 15 MW which is only about 3 MW less than the peak load of 18.2 MW under the full electrification scenario. In other words, both the financial outlay and the resulting scale are appropriate for MWL to consider under the full electrification case.

Table 28 uses the same assumptions that were used for the single site storage project, and results in a net benefit of $5.2 million over 20 years. The conclusion is that storage makes financial sense generally, and a full storage build out is a plausible, cost reducing strategy.

Table 31: Storage Strategy Volumes & Costs

Year	Avoided NOATT + Capacity	90% of Cumulative MW	Annual Avoided Cost	ESSA Cost	Net Cost (-) or Benefit (+)
0	$12.25	1.4	$213,103	$320,970	($107,867)
1	$12.95	2.9	$448,584	$641,941	($193,357)
2	$13.69	4.3	$708,067	$962,911	($254,845)
3	$14.47	5.7	$993,081	$1,283,881	($290,800)
4	$15.29	7.1	$1,304,991	$1,604,852	($299,861)
5	$16.16	8.5	$1,645,630	$1,925,822	($280,192)
6	$17.08	9.8	$2,010,855	$2,246,792	($235,938)
7	$18.06	11.1	$2,402,209	$2,567,763	($165,554)
8	$19.09	12.3	$2,821,334	$2,888,733	($67,400)
9	$20.17	13.5	$3,269,967	$3,209,703	$60,264
10	$21.32	13.5	$3,456,355	$3,209,703	$246,652
11	$22.54	13.5	$3,653,368	$3,209,703	$443,664
12	$23.83	13.5	$3,861,610	$3,209,703	$651,906
13	$25.18	13.5	$4,081,721	$3,209,703	$872,018
14	$26.62	13.5	$4,314,380	$3,209,703	$1,104,676
15	$28.14	13.5	$4,560,299	$3,209,703	$1,350,596
16	$29.74	13.5	$4,820,236	$3,209,703	$1,610,533
17	$31.43	13.5	$5,094,990	$3,209,703	$1,885,286
18	$33.23	13.5	$5,385,404	$3,209,703	$2,175,701
19	$35.12	13.5	$5,692,372	$3,209,703	$2,482,669
20	$37.12	13.5	$6,016,837	$3,209,703	$2,807,134
Levelized Cost	**$21.03**				
NPV			**$34,155,563**	**$29,005,436**	**$5,150,127**

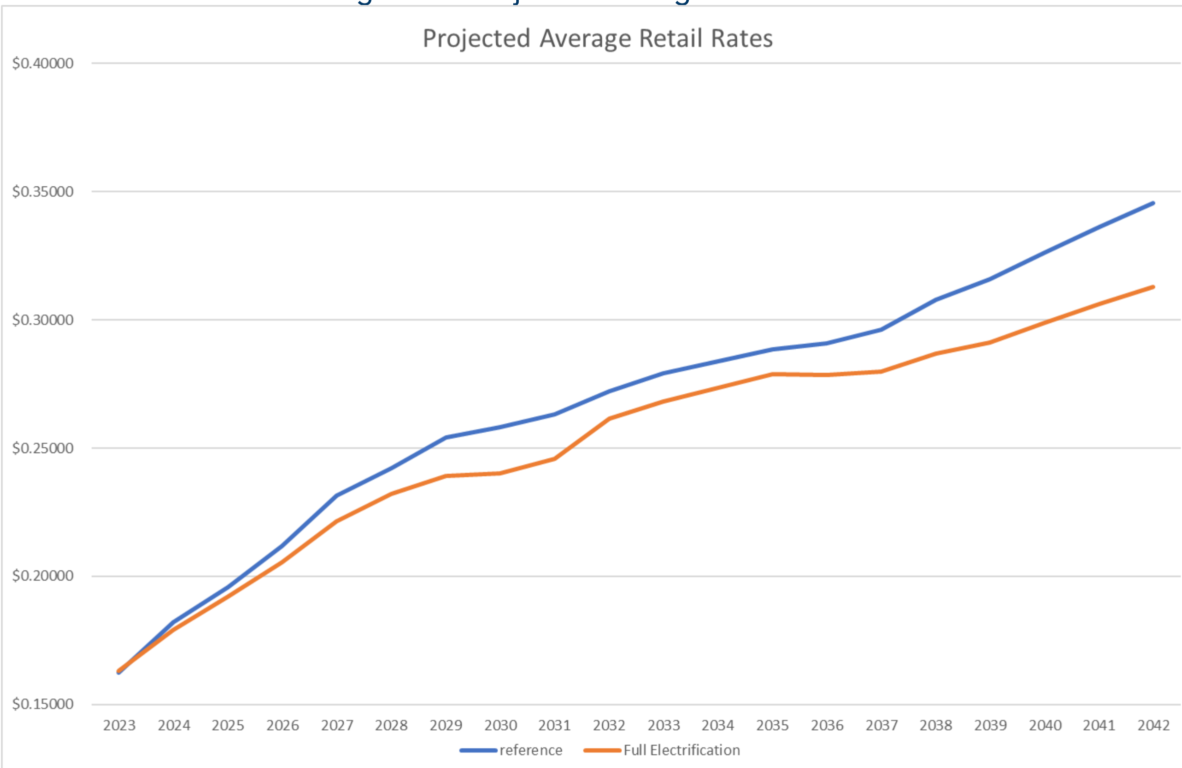
FINANCIAL ASSESSMENT

MWL has drafted and gained approval of its formal policies intended to guide capital investment, the issuance of related debt, and maintenance of adequate operating reserves (see Appendix K). In light of the extensive capital investment anticipated in this IRP, clear guidelines will be a necessity to ensure an appropriate use of external financing that respects legal and regulatory restrictions while striking a balance between the use of debt and internally generated funds.

In Appendix J, the IRP Reference Case Projected Financial Results, indicates that MWL's capital structure reaches 45% by 2030 then gradually tails off over the remaining decade. In the IRP Full Electrification Case Projected Financial Results (see Appendix J) we see the debt percent peak at about 48% in 2034, tailing off more slowly over the remainder of the study period. Superimposing the additional $40 million storage investment discussed above on the full electrification case increases the debt percent to a peak of 65% by 2030. It becomes clear MWL's ability to finance the required capital investment could be sensitive to the magnitude and timing of electrification related system upgrades. Further, it is worth noting that 30 V.S.A. §108 requires PUC and voter approval when debt reaches or exceeds 50% of total assets; whether this threshold becomes an issue in the future remains to be seen but the potential for this to become an impediment to financing system upgrades could develop.

In Appendix J, reference case, and Full Electrification case also provide a summary of projected annual revenue requirements, retail rates, key cash related items and financial ratios. Conclusions that might be drawn are that while impacts of electrification increase revenue requirements, load growth mitigates the impact on average rates. As shown in Figure 38, in either case the impact on average retail rates is more pronounced in the early years of the study, as large system investments are made, with the rate trajectory leveling off as load growth assists in absorbing the increased costs.

Figure 38: Projected Average Retail Rates



ACTION PLAN

VII. ACTION PLAN

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

ACTION PLAN

- Implement an AMI system as reflected in the recent RFP within the 2024–2025-time frame.
- Develop Technology Roadmap and pursue CIS, GIS & other indicated upgrades
- Rate Design – implement EV rates; prepare for comprehensive, dynamic rate design as detailed data becomes available through AMI
- Investigate options for engaging customers in active load control programs and tariffs, including end-uses such as electric thermal storage, CCHPs, and HPWHs.
- Continue research & engineering/planning for system-wide layered storage program.
- Continue Hydro Relicensing & upgrade program to support Load Management needs.
- 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; consider forward purchases, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk.
- Investigate construction or participation in a 4-7 MW solar project(s) for TIER II compliance purposes.
- Continue to Identify and deliver prescriptive and/or custom Energy Transformation programs for TIER III compliance purposes.
- Pursue obtaining full legal easement/access rights to the right of way for the Morrisville to Stowe transmission/distribution corridor for critical maintenance and upgrade rights.

APPENDIX

APPENDIX A: 2023 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA Tier 3 2023 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B – MWL Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – MWL – 2018-2022 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: AMI DECISION MAKING PROCESS

This appendix is provided separately in a file named:

Appendix F – AMI Decision Making Process.pdf

APPENDIX G: ITRON'S LOAD FORECAST REPORT

This appendix is provided separately in a file named:

Appendix G – MWL IRP23 Demand Report.pdf

APPENDIX H: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

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

APPENDIX I: MWL PROJECTED CAPITAL INVESTMENT

This appendix is provided separately (and includes the reference case and full electrification case projected capital) in a file named:

Appendix I – MWL Projected Capital Investment.pdf

APPENDIX J: PROJECTED FINANCIAL RESULTS

This appendix is provided separately (and includes the reference case and full electrification case projected financial results) in a file named:

Appendix J – MWL Projected Financial Results.pdf

APPENDIX K: FINANCIAL POLICIES

This appendix is provided separately in a file named:

Appendix K – MWL Financial Polices.pdf

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
CSO	Capacity Supply Obligation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
DTLM	Distribution Transformer Load Management
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems
GMP	Green Mountain Power
HP	Heat Pump
HPWH	Heat Pump Water Heater
IRA	Inflation Reduction Act

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
LCPC	Lamoille County Planning Commission
LIHI	Low Impact Hydro Institute
LRTP	Long-Range Transmission Plan
MAPE	Mean Absolute Percent Error
MDMS	Meter Data Management System
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
MWL	Morrisville Water & Light Department
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NOAA	National Oceanic and Atmospheric Administration
NYPA	New York Power Authority
OMS	Outage Management System
PFP	Pay for Performance
PPA	Power Purchase Agreement
PSD	Public Service Department or "Department"
PUC	Public Utility Commission
PVRR	Present Value of Revenue Requirement
R^2	R-squared
REC	Renewable Energy Credit
RES	Renewable Energy Standard
ROW	Right-of-way

RTLO	Real-Time Load Obligation
SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQRP	Service Quality & Reliability Performance, Monitoring & Reporting Plan
TAG	Technical Advisory Group
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)
VEC	Vermont Electric Cooperative
VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VFD	Variable Frequency Drive
VPPSA	Vermont Public Power Supply Authority
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTrans	Vermont Agency of Transportation
WBHP	Whole Building Heat Pump
WQC	Water Quality Certificate

Vermont Public Power Supply Authority

2023

Renewable Energy Standard

Tier III Annual Plan

Filed via ePUC
November 1, 2022

Vermont Public Power Supply Authority
PO Box 126
5195 Waterbury-Stowe Road
Waterbury Center, VT 05677
www.vppsa.com

Table of Contents

Introduction

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing its 2023 Renewable Energy Standard: Tier III Annual Plan describing the proposed strategy to meet its members' energy transformation program compliance.

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 III") projects or purchase additional Renewable Energy Credits ("RECs") from new, small, distributed renewable generators ("Tier II").

As VPPSA's Tier III Program evolves, process improvements and responsiveness to customer trends, needs, and priorities are continuously monitored. Providing safe, reliable, and affordable electricity is a critical factor in supporting the State's renewable energy goals and expanded offerings must be evaluated to ensure cost-effectiveness.

VPPSA members continue to prioritize strategic electrification that minimizes cost-shifting or upward rate pressures; this is especially important in 2023 considering substantial increases in cost-of-living expenses, geopolitical conflicts straining the global economy, and mounting supply chain constraints because of inflation and shortages resulting from the COVID-19 pandemic. Responsiveness to needs of all customer classes remains a priority to ensure sustainable growth and community strength.

In consideration of all these factors, VPPSA submits its 2023 Tier III Annual Plan which aims to increase collaboration with the State's Energy Efficiency Utilities, strengthen opportunity for point-of-sale incentives, and streamline processes to encourage increased participation in energy transformation projects for residential, commercial, and industrial customers.

Respectfully,

Sarah E. Braese
Manager of Government and Member Relations
Vermont Public Power Supply Authority
(802) 882-8509

VPPSA Tier III Obligation Requirements

VPPSA Member Utilities'[1] Tier III obligation 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.[2]" Tier III requirements increase by two-thirds of a percent annually .

In 2023, VPPSA's aggregate requirement is estimated to be 16,531 MWh equivalent in savings, representing 4.67% of members' 2022 estimated Annual Retail Sales (kWh). The 11 VPPSA member utilities plan to meet their Tier III 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."

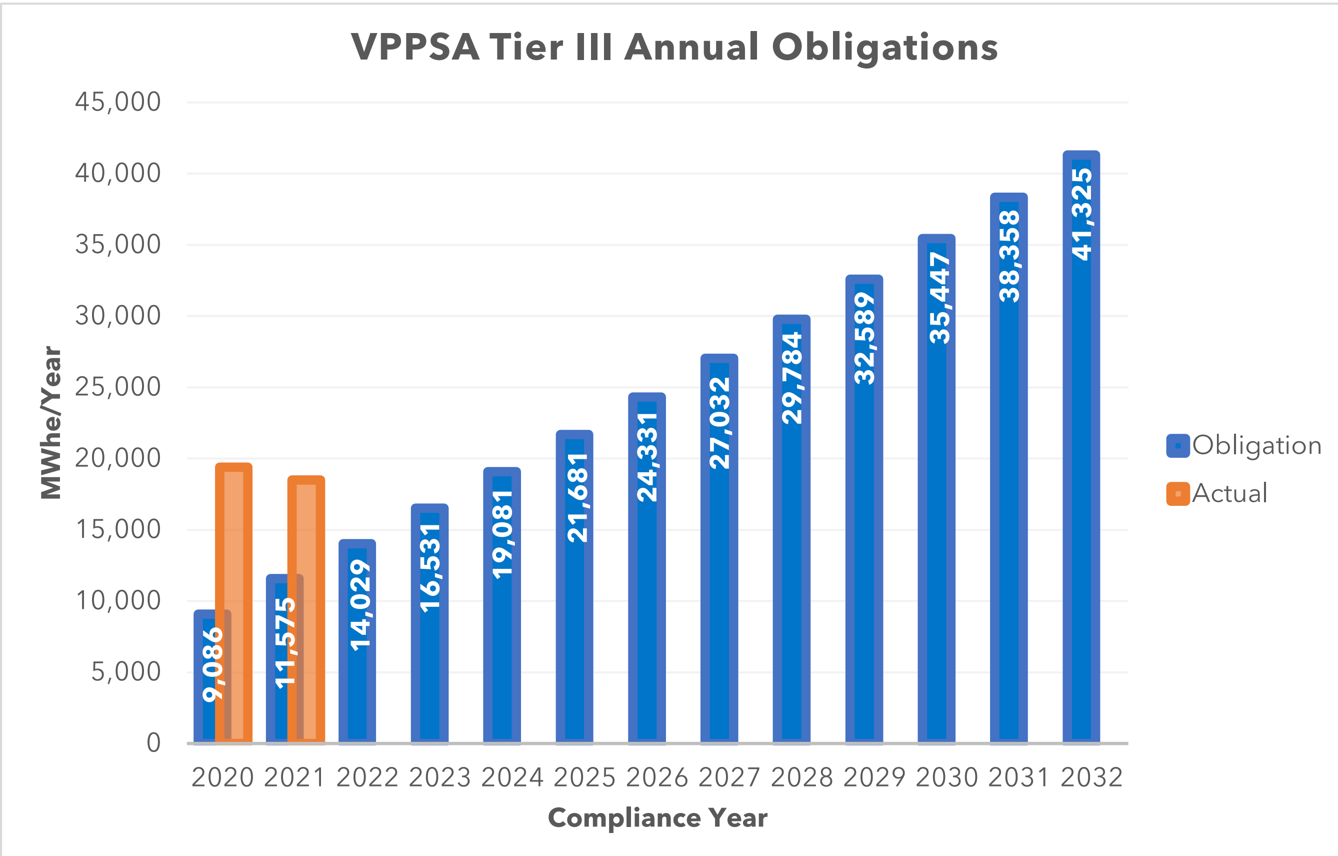
VPPSA's projected Tier III annual MWh equivalent (MWhe) savings obligations through 2032 and compliance performance are illustrated in Figure 1: VPPSA Tier III Annual Obligations (see Page 3)[3].

[1] VPPSA Members include Barton Village; 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; and Swanton Village.

[2] 30 V.S.A. § 8005(a)(3)(B)

[3] 2020 and 2021 Tier III "Actual" MWhe Savings as reported from VPPSA's Annual RES Compliance Filings in Case 21-1045-INV and Case 22-0604-INV, respectively.

Figure 1: VPPSA Tier III Annual Obligations



Summary of 2022 Projects

VPPSA is on track to meet its 2022 Tier III requirements of 14,029 MWhe through a portfolio of prescriptive and custom energy transformation measures.

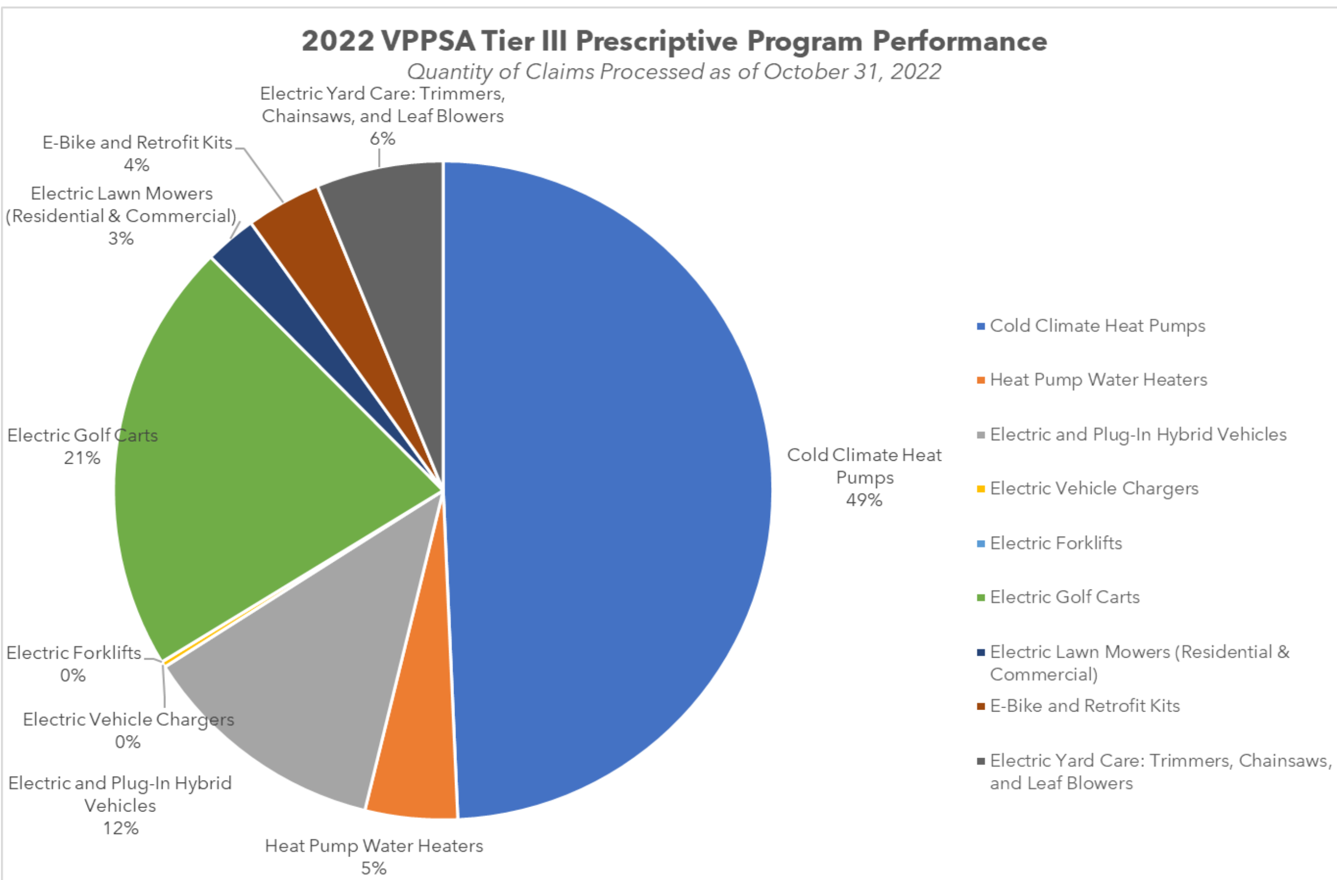
Prescriptive measures are administered using a combination of midstream and downstream incentives:

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. Electric Lawn Mowers (Residential & Commercial)
8. E-Bike and Retrofit Kits
9. Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers

Of the prescriptive rebates offered, cold climate heat pumps represent a significant portion of the total number of measures processed to-date. VPPSA's strategy continues to focus on cost-effective prescriptive and custom Tier III measures which meet member and customer needs. This strategy includes monitoring consumer trends, potential grid infrastructure impacts, and external socio-economic factors that may affect supply chains and, ultimately, future compliance.

Figure 2: 2022 VPPSA Tier III Prescriptive Program Performance reflects processed claims as of October 31, 2022 and is intended for illustrative purposes only[4]. This data is not reflective of total nor expected claims for the entire 2022 Tier III Compliance year.

Figure 2: 2022 VPPSA Tier III Prescriptive Program Performance



[4] Figure 2 represents the quantity of completed prescriptive rebate claims processed to-date and is intended for illustrative purposes only. This data does not reflect the entirety of 2022 Tier III Compliance claims, nor does it represent expected compliance performance by year-end.

VPPSA recognizes that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is, on average, substantially lower than both prescriptive incentives and Tier II RECs.

Custom projects, typically for commercial and industrial customers, include incentives for line extensions, service upgrades, or other energy transformation projects that reduce greenhouse gas emissions and reliance on fossil fuels. VPPSA continues to seek and support a robust pipeline of custom projects at various stages in their development. As it has been previously expressed, timelines for custom projects are often longer than the decision-making process for prescriptive rebates. For that reason, some custom projects may not be completed until 2023 or later.

2023 Tier III Program Overview

The focus of VPPSA's 2023 Tier III Program is to support Vermont's electrification transition while ensuring rates are affordable and maintaining reliability of service. It is important for distribution utilities to prioritize reliability as an assurance for customers during the decision-making process to adopt new electrification measures.

As in previous years, VPPSA plans to meet its 2023 Tier III requirements by further diversifying its portfolio of offerings at costs that mitigate pressure on electric rates. This portfolio includes a combination of prescriptive and custom measures and use of Tier II RECs, if needed.

VPPSA intends to maintain its current portfolio of prescriptive measure offerings with the addition of offering Smart Thermostats, and a renewed focus on improving the processes by which customers can obtain these financial incentives. In particular, VPPSA will be implementing a new rebate processing platform to better serve its members' customers by streamlining and expediting the application and claims approval process.

Prescriptive Measure Savings are calculated using the Net Lifetime MWh Saved measure characterizations created by the Tier III Technical Advisory Group ("TAG.").

To ensure a diversity of offerings that ensures equity in accessibility and customer participation, VPPSA has further defined its 2023 Tier III Program measures into four main categories, by type of electrification (aka energy transformation):

1. Transportation
2. Thermal
3. Commercial Equipment & Appliances
4. Residential Equipment & Appliances

Incentive offerings are explained in greater detail below.

Transportation

State and Federal funding and policy making decisions continue to support the expansion of the electric vehicle market and electric vehicle charging infrastructure. VPPSA plans to continue incentive offerings that encourage customer adoption, with a focus on equity and strategic monitoring of potential changes in load management.

Electric Vehicles (EV) and Plug-In Hybrids (PHEV)

VPPSA will continue to offer customer incentives for the purchase or lease of new and used EVs and PHEVs in 2023 as both point-of-sale or post-purchase rebates.

The customer incentives for EV and PHEVs are as follows:

Measure Type	Base Incentive	Additional Low-Income Incentive	Estimated Total MWhe Savings
Electric Vehicle (New)	$ 1,000	$ 400	1,007 MWhe
Electric Vehicle (Used)	$ 500	N/A	168 MWhe
Plug-in Hybrid Vehicle (New)	$ 500	$ 400	517 MWhe
Plug-in Hybrid Vehicle (Used)	$ 250	N/A	65 MWhe

In its second year of partnering with vehicle dealerships around the state to offer point-of-sale incentives, VPPSA is looking to expand its program to additional dealerships and increase awareness of incentive availability to member customers. Customers who purchase or lease a vehicle from a participating dealership will receive an instant, point-of-sale incentive discount. Dealerships then submit the required application and documentation to VPPSA for reimbursement.

Post-purchase rebate applications will continue to be accepted from eligible customers who provide all necessary documentation.

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.

Using data analytics from the 2022 EVSE Powershift Pilot Program with Efficiency Vermont (EVT), VPPSA hopes to develop a more robust EV charging network within its member service territories to meet member and customer needs. The PowerShift Pilot Program provides residential customers with Open Charge Point Protocol ("OCPP") charging equipment, capable of integrated with multiple control platforms through open-source technology. As part of the Pilot, chargers are programmed to provide charging during off-peak hours and may facilitate direct control of EV charging in the future.

Thermal

As described above in relation to transportation, VPPSA recognizes that alleviating energy burden of its customers must also include supporting thermal, or heating and cooling electrification technologies such as cold climate heat pumps.

In collaboration with Efficiency Vermont (EVT) and other Vermont distribution utilities, beginning January 2021, EVT began administering state-wide utility heat pump incentive programs. This partnership and collaboration have greatly expanded the adoption and installation of these fuel-saving technologies, particularly in VPPSA member service territories which had been historically underrepresented in state-wide adoption metrics.

Cold Climate Heat Pumps

In 2023, VPPSA will continue to offer incentives on ductless and whole building heat pump technology through its partnership with EVT to administer midstream, point-of-sale and downstream heat pump incentives on VPPSA's behalf.

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

Ductless Heat Pumps:

In 2023, Efficiency Vermont will continue to administer the additional $250 utility incentive for ductless heat pumps as an instant, point-of-sale discount.

Utility incentives are applied when customers utilize participating contractors or distributors. Efficiency Vermont batches and reports incentives applied for VPPSA member customers and invoices VPPSA monthly for reimbursement. VPPSA expects a similar volume of ductless heat pump incentives to what was offered in 2022, however supply and labor constraints may impact the overall uptake and performance.

VPPSA is also partnering with Efficiency Vermont and other Vermont electric utilities to offer ductless heat pumps to income-qualifying households at no cost to the utility customer. These incentives would be offered to income-qualifying customers who have completed weatherization services provided through the Weatherization Assistance Program ("WAP"). The cost of the heat pumps will be shared between the distribution utilities and Efficiency Vermont, with Efficiency Vermont's portion coming 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. VPPSA anticipates 11 ductless heat pumps will be installed in its member utility territories in 2023.

As part of its Tailored Efforts in partnership with Efficiency Vermont, VPPSA expects to offer a low-to moderate-income ducted and ductless heat pump adder for qualifying customers of 2023 Tailored Effort utilities. In 2022, VPPSA provided a $400 downstream heat pump incentive adder to income eligible customers of Hardwick Electric Department, Lyndonville Electric Department, and Morrisville Water & Light. VPPSA's adder was combined with the $200 statewide income adder from Efficiency Vermont, plus an additional $400 contribution from Efficiency Vermont. The total adder including both VPPSA and Efficiency Vermont's contributions came to $1,000 for low-to moderate-income customers. VPPSA and Efficiency Vermont are currently in conversations about offering a similar incentive in 2023 to customers of Tailored Effort utilities.

Whole Building Heat Pumps:

VPPSA will continue to offer incentives on centrally ducted heat pumps and air-to-water 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. VPPSA will offer the full incentive and claim 100% of the thermal savings. Efficiency Vermont may offer an additional incentive and claim electric efficiency savings.

Efficiency Vermont will continue to administer the incentive 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 2022.

VPPSA and Efficiency Vermont are partnering on a low-to moderate-income ducted and ductless heat pump adder for qualifying customers of 2023 Tailored Effort utilities. See the "Ductless Heat Pumps" section for further information.

VPPSA will also continue to offer ground source heat pump ("GSHP") incentives on a prescribed custom basis.

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.

Commercial Equipment & Appliances

As key fixtures and economic drivers in member communities, VPPSA is pleased to continue offering specific prescriptive incentive measures to support the electrification of commercial equipment and appliances.

Forklifts

In support of the various business customers throughout VPPSA's member territories, VPPSA intends to continue offering a $2,500 rebate incentive for new electric forklifts. Increased marketing and outreach will be conducted to various businesses in an attempt to inform and encourage electrification of this equipment.

Golf Carts

In 2023, VPPSA continues to offer a $100 rebate incentive for customers that purchase new electric golf carts. As with forklifts, VPPSA intends to increase marketing and outreach to the various businesses which may benefit from the investment in new, electric golf carts.

Commercial Property Maintenance

Commercial Lawn Mowers

VPPSA will be offering a $1,200 incentive for purchase of an electric, commercial ride-on lawn mower. A $100 incentive will be offered for purchase of an electric, commercial push mower.

Commercial Leaf Blowers

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

Commercial Trimmers

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

Commercial Chainsaws

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

Residential Equipment & Appliances

VPPSA recognizes the enormous impact that local, state, and federal policies can have on the average residential customer and is pleased to offer the following suite of prescriptive incentives in 2023.

Electric Bikes (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. Additionally, VPPSA intends to strengthen relationships with various e-bike retailers throughout the state to explore point-of-sale agreements, similar to those established with electric vehicle dealerships.

Residential Property Maintenance

In 2022, VPPSA saw increased customer claims for yard care rebates which will continue to be offered in 2023. Although these measures often have a high $/MWh cost, they are often a lower cost, entry level, electrification of equipment for the average customer.

Residential Lawn Mowers

VPPSA will continue to offer a $50 incentive for the purchase of either a residential push or ride-on electric lawn mower.

Residential Leaf Blowers

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

Residential Trimmers

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

Residential Chainsaws

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

Smart Thermostats

As headlines warn of rising home heating costs, VPPSA intends to continue expanding partnerships with external entities to maximize efficiencies and weatherization of customers' homes. With that in mind, VPPSA is pleased to introduce a new $50 prescriptive incentive for smart thermostats in 2023. With more advanced controls and monitoring, this new measure is an affordable way to help customers better mitigate impacts of rising fuel costs and ideally, their overall energy burden.

Custom Measures

For commercial and industrial ("C&I") customers seeking more sophisticated energy transformation projects, VPPSA intends to continue offering Custom Measures, where appropriate. VPPSA maintains and tracks a pipeline of customers exploring potential Tier III customer projects, in collaboration with the work of Efficiency Vermont (EVT).

Due to various internal and external factors, identified custom projects with estimated completion in 2022 may indeed be postponed to 2023, including 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's Key Accounts program is one tool to assist in the 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 III 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 III credits. Upon approval of the VPPSA Board of Directors, VPPSA may fund custom projects through its Tier III budget and allocate savings among its members.

In 2022, VPPSA received an appropriation of $1 million from the Department of Energy through a federal earmark provided by Senator Sanders. VPPSA is using this funding to pilot an R&D project to determine if on-bill financing of custom commercial and industrial energy transformation projects could incentivize this customer class to reduce fossil fuel use. VPPSA is partnering with Efficiency Vermont and a yet-to-be-determined financial institution to explore and offer low-to-no interest financing options for projects that pass screening criteria. At this time of this report, the pilot project is still under negotiation with the Department of Energy for the final award announcement. We expect this Business Energy Repayment Assistance Program ("BERAP") will launch in 2023.

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

Tier II RECs

VPPSA manages its member Tier III compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier II RECs. Under this approach the Tier II REC price acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings.

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

Should Tier II REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier III planning document.

Best Practices: Load Growth & Management

Over the long-term, energy transformation programs have the potential to increase loads for all Vermont utilities, however load impact potential is a complex scenario influenced by several factors. VPPSA members systems remain robust, and the expected growth in annual and local peak demand associated with proposed measures are supported and sustained through monitoring deployment.

In alignment with industry best practices, underlying assumptions used in VELCO's Long-Range Transmission Plan ("LRP") are used to develop members' Integrated Resource Plans (IRP). As a result, IRPs incorporate the State's latest outlook for Electric Vehicle (EV) and Cold Climate Heat Pump (CCHP) adoption. Additionally, State and Federal investments in electrification technologies for the thermal and transportation sectors are important factors that contribute to forecasting models in relation to consumer trends and adoption of electrification measures.

From a technical perspective, there are many credible options for controlling load which VPPSA continues to monitor, pilot, and deploy where shown to be economically competitive.

As part of VPPSA's long-term advanced metering infrastructure and GIS projects, member utilities will soon have the capacity to further refine analytics around load monitoring and forecasting correlating to energy transformation programs. This is particularly important as state policies continue to support electrification of transportation and thermal sectors. In the interim, VPPSA continues its partnership with Virtual Peaker, which supports internal utility behavioral demand-response programs that strategically maximizes load-reducing generation during high-cost time periods.

As previously stated in the Transportation Electrification section, VPPSA and Efficiency Vermont are partnering on a PowerShift Pilot that may mitigate the grid impacts of EV charging. Residential customers who purchase or lease an all-electric vehicle are eligible to receive a free level 2 charger and a $500 incentive for installation. These incentives are funded by Efficiency Vermont. Customers must provide proof of setting a daily charging schedule outside of peak hours to be eligible for the incentives. VPPSA anticipates installing 15-20 scheduled chargers in 2023. VPPSA expects to learn how incentives and rebates affect charging behavior through its PowerShift partnership with Efficiency Vermont. That said, alternative incentives like rate structures may similarly impact when utility customers choose to charge their electric vehicles. VPPSA applied for and received grant funding to study time-of-use rates as a means to shift utility customer demand to off-peak times. VPPSA also anticipates applying for funding through the Infrastructure Investment and Jobs Act. The Department of Public Service is receiving $3.2 million each year over a five-year period, which may be sub-awarded to utilities. VPPSA continues to work collaboratively with the Department and other distribution utilities to identify eligible projects that lead to investments in a smarter grid with greater flexibility.

VPPSA continues to pursue utility-scale storage as a cost-effective means of achieving demand reductions for its members. Current constraints on the supply chain have created complex challenges in equipment and material sourcing, however battery storage remains a key tool to meet demand reductions.

Lastly, as a method to encourage participation in buildings which meet established performance standards, thereby helping to manage load control, VPPSA also provides an additional $200 heat pump incentive for units installed in weatherized buildings.

Minimum Standards: Program Administration

As previously stated, VPPSA administers its Tier III Program in aggregate, on behalf of all members. As such there are a number of standards and processes which are employed to meet minimum standards and compliance.

In administering prescriptive measures, VPPSA maintains standard customer privacy and data security procedures to protect sensitive information. VPPSA also implements necessary internal controls to ensure the integrity of the Program. This requires a segregation of duties in the receipt, processing, and approval of incentive applications.

Equitable Opportunity

VPPSA strives to ensure that Tier III energy transformation programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier III incentives described in this Plan are 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.

Consistent with Rule 4.413(c), each year VPPSA tracks and reports Tier III participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income). For incentives administered directly by VPPSA, customers must answer a tracking question related to their household income. In the case of Efficiency Vermont administered incentives, VPPSA assumes 31% of statewide residential program uptake is from low-income households. This assumption was developed in partnership with Efficiency Vermont and the Department of Public Service.

Participation and spending are monitored and reviewed each year to inform program planning for future years. This data is included in VPPSA's Tier III savings filed in March and RES Compliance Filing in August. Each year, and 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.

With some measures, such as electric vehicles, VPPSA is providing a significantly higher incentive to income-eligible customers to help offset cost barriers to 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.

Low-to moderate-income Vermonters face numerous hurdles when choosing to electrify. The state has an old building stock and is often only supplied with 100-amp electric service, which is inadequate to accommodate added electrification measures. Upgrades to 200-amp service can be costly and may prevent households with lower incomes from pursuing electrification despite robust incentives. In 2022, VPPSA applied for VLITE funding to reduce this barrier. In 2023, VPPSA expects to deploy funding for in-home service panel upgrades for income-qualifying customers who pursue heat pumps and all-electric vehicles.

Financing is another tool that can be used to make Tier III measures accessible to customers. In 2022, VPPSA encouraged member enrollment in the Weatherization Repayment Assistance Program (WRAP), financed through the Vermont Housing Finance Agency, to facilitate on-bill repayment and incentives for qualifying customers. Additionally, as mentioned above VPPSA is completing negotiations with the US Department of Energy to pilot a Business Energy Repayment Assistance Program (BERAP) which aims to provide a similar structure of on-bill financing for commercial and industrial energy transformation projects.

Finally, VPPSA's Tier III 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 III 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 III programs and cost-shifting among customers is minimized.

VPPSA's Utility Present Value Life Cycle Cost 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.

Partnership & Collaboration

In 2023, VPPSA plans to continue actively working with both public and private partners to execute our Tier III plan in the most cost-effective way without sacrificing the customer experience.

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). In 2023, the Village of Enosburg Falls, Village of Johnson Electric, and Orleans Electric Department will be participants in the Tailored Efforts program. Additionally, as previously mentioned, VPPSA and Efficiency Vermont plan to partner on load management pilots.

Outside of VPPSA's partnership and collaboration with Efficiency Vermont, expansion of the point-of-sale incentive agreements with auto dealerships is expected in 2023. Not only will VPPSA plan to enter agreements with more dealerships across the state, but also seek to establish a similar agreement with businesses which sell electric bikes in Vermont.

Marketing & Communications

VPPSA continues to engage in utility customer interaction, marketing and communications. With the addition of Tier III 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 and streamlined rebate processing platform
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops
- Car dealer and e-bike supplier outreach
- EVT contractor and distributor outreach
- Direct outreach to Key Account customers

Cost-Effectiveness & Equity

VPPSA's Tier III planning included consideration of the suite of measures in the 2023 Tier III Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA has initiated an overall analysis of the Tier III portfolio's diversity to ensure both cost-effectiveness and equity for customers at varying levels of spending ability while still meeting regulatory compliance.

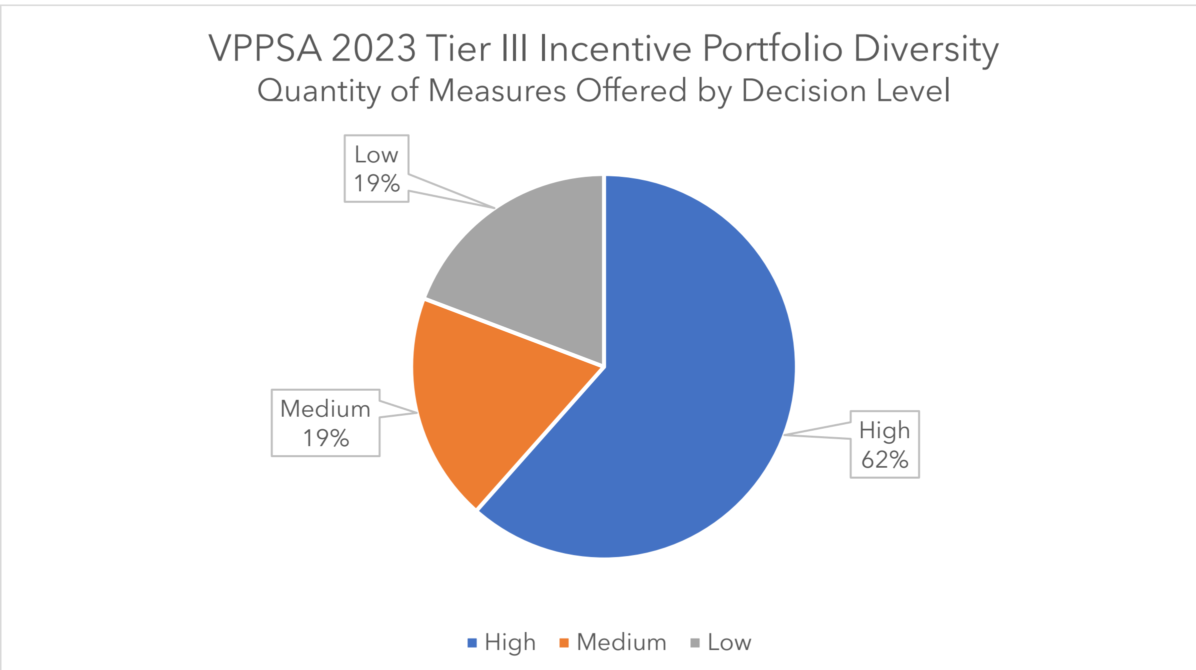
The analysis of VPPSA's 2023 Tier III Incentive Portfolio Diversity included a comparison of the quantity of measures offered in relation to:

1. Decision Level (i.e., impact of monetary investment)[5];
2. Energy Transformation Value Level (i.e., Savings/MWH)[6];
3. Type of Electrification[7]

Illustrations of this analysis are shown in Figure 3, Figure 4, and Figure 5, respectively.

The purpose of performing this analysis for the 2023 Tier III Incentive Program is to identify areas of potential cost-effective growth or expansion in offerings. VPPSA also envisions this analysis will help position our members to better respond to the various socio-economic and external factors which affect customer behaviors related to electrification now and in the future.

Figure 3: Tier III Portfolio Diversity by Decision Level



[5] Decision Level (High, Medium, Low) is calculated using the 2023 TAG Planning Tool's "Measure Cost" minus VPPSA's measure Incentive. High = Cost > $2,500; Medium = $501 < $2,499; Low = > $500.

[6] Energy Transformation Value Levels are determined based on the TAG Planning Tool's Savings/MWh: High = Savings > 50.1 MWh; Medium = Savings 10.1 MWh < 50 MWh; Low = Savings < 10 MWh

[7] Type of Electrification is classified into five broad categories, for the purposes of better aligning and analyzing the diversity of measures offered to customers: Thermal, Commercial Equipment & Appliances, Residential Equipment & Appliances, Transportation, and Custom Commercial & Industrial.

Figure 4: Tier III Portfolio Diversity by Energy Transformation Value

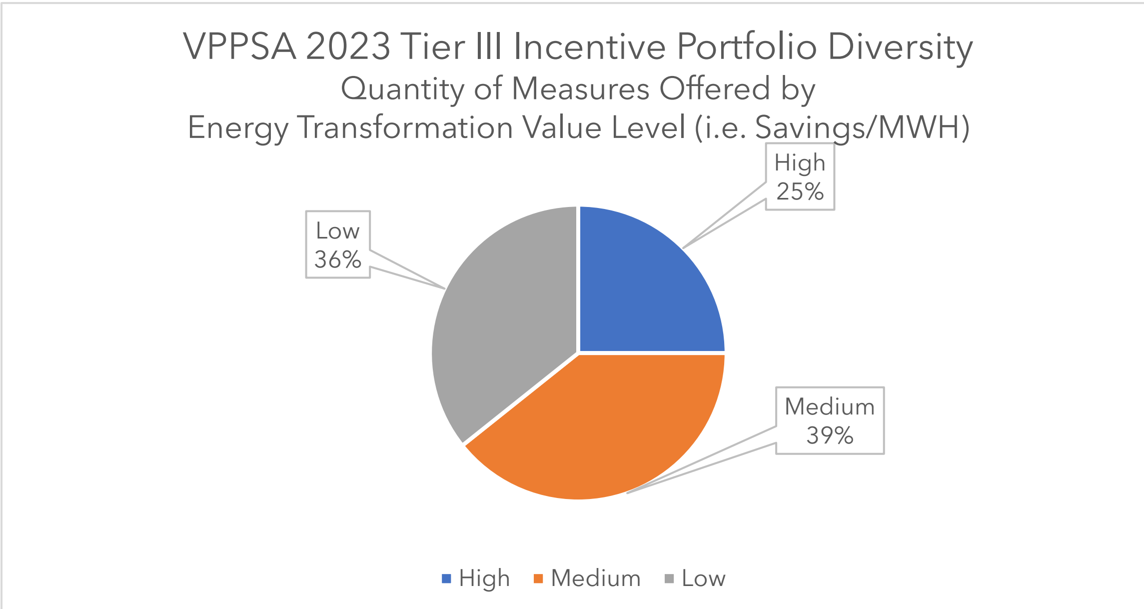
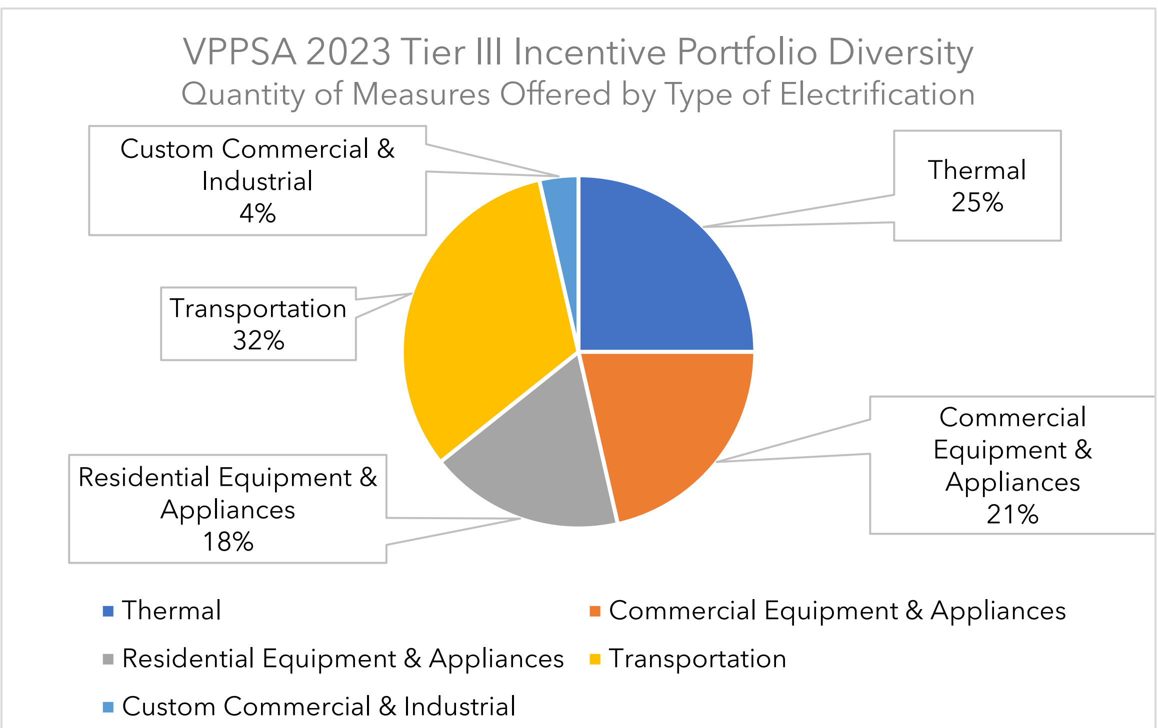


Figure 5: Tier III Portfolio Diversity by Type of Electrification



Utility Present Value Life Cycle Cost

VPPSA estimated the utility's net revenue for each of the 2023 Tier III measures. The analysis was conducted to provide a key input to the 2023 Tier III reporting template, specifically the 'Present Value Net Revenue' column. These estimates, when combined with other inputs to the template, ultimately calculate the 'Utility Present Value Life Cycle Cost Net' in $/MWhe.

The methodology followed a five-step process that netted utility costs from utility revenues.

First, the Tier III Planning Tool was used to gather several key inputs.

- Measure Life,
- Added kWh new system,
- Existing System MMBtu Displaced, and
- Assumed Fuel.

Second, seasonal load shapes were assumed for each measure. Specifically,

- Winter Peak MWH
- Winter Off-Peak MWH
- Summer Peak MWH
- Summer Off-Peak MWH
- Winter Peak MW
- Summer Peak MW

Third, current estimates of avoided costs were gathered. Energy, capacity, REC and transmission costs were sourced from VPPSA's budget models, and the cost of fossil fuels and non-embedded carbon were gathered from the AESC 2021 report.

Fourth, the volumes (MWH and MW) were multiplied by the appropriate avoided costs to arrive at an avoided cost estimate from the utility's perspective.

Fifth, the utility revenues were calculated using blended average retail rates as forecast during the 2019-2020 IRP cycle.

Finally, the 'Present Value Net Revenue' was calculated by subtracting the costs from the benefits and discounting the cash flows back to 2023 at a 5% discount rate.

The results of this analysis, as summarized in the Tier III reporting template, appear in Appendix B: 2023 Tier III Reporting Template & Life Cycle Cost Analysis.

Appendix A: Analysis of VPPSA's 2023 Tier III Incentive Portfolio Diversity

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Cold Climate Heat Pump (CCHP)	High	Medium	Thermal	$ 2,644.48
Cold Climate Heat Pump (CCHP) (weatherized)	Medium	Medium	Thermal	$ 2,444.48
Cold Climate Heat Pump (CCHP) Income Eligible Act 151	Medium	Medium	Thermal	$ 794.48
Heat Pump Water Heater	Medium	Medium	Thermal	$ 1,437.41
Whole Building Heat Pump (WBHP) - Air to Water - Residential	High	High	Thermal	$ 5,403.67
Whole Building Heat Pump (WBHP) - Ducted - Commercial	High	High	Thermal	$ 2,960.79
Whole Building Heat Pump (WBHP) - Ducted - Residential	High	High	Thermal	$ 2,960.79
Electric Forklift (New)	#VALUE!	High	Commercial Equipment & Appliances	#VALUE!
Electric Golf Cart (New)	#VALUE!	Low	Commercial Equipment & Appliances	#VALUE!
Lawnmower Commercial Electric Push	Low	Medium	Commercial Equipment & Appliances	$ 400.00
Lawnmower Commercial Ride-On	High	High	Commercial Equipment & Appliances	$ 20,173.00

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Yard Care Commercial Chainsaws	Medium	Low	Commercial Equipment & Appliances	$ 752.45
Yard Care Commercial Trimmers, Edgers, and Cultivators	Medium	Low	Commercial Equipment & Appliances	$ 569.94
Lawnmower Residential Electric Push	Low	Low	Residential Equipment & Appliances	$ 369.00
Lawnmower Residential Ride-On	High	Low	Residential Equipment & Appliances	$ 3,839.69
Smart Thermostat	Low	Low	Residential Equipment & Appliances	$ 125.00
Yard Care Residential Chainsaws	Low	Low	Residential Equipment & Appliances	$ 358.95
Yard Care Residential Trimmers, Edgers, and Cultivators	Low	Low	Residential Equipment & Appliances	$ 246.95
Electric Bike	High	Low	Transportation	$ 2,725.00
Electric Vehicle (New All Electric - Low Income)	High	Low	Transportation	$ 14,308.00
Electric Vehicle (New All Electric)	High	Medium	Transportation	$ 14,708.00
Electric Vehicle (New Plug-in Hybrid - Low Income)	High	Medium	Transportation	$ 6,401.00
Electric Vehicle (New Plug-in Hybrid)	High	Medium	Transportation	$ 6,801.00
Electric Vehicle (Used All Electric)	High	Medium	Transportation	$ 15,208.00
Electric Vehicle (Used Plug-in Hybrid)	High	Medium	Transportation	$ 7,051.00

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Electric Vehicle Charging Stations (Level 2 Public)	High	Medium	Transportation	$ 5,400.00
Electric Vehicle Charging Stations (Level 2 Workplace)	High	High	Transportation	$ 2,700.00

Appendix B: 2023 Tier III Reporting Template & Life Cycle Cost Analysis

2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Cold Climate Heat Pump (CCHP)	$75,952	$13,039	$62,913	$12.33	$10.22
Cold Climate Heat Pump (CCHP) (weatherized)	$7,056	$144,605	($137,549)	$17.63	($343.70)
Cold Climate Heat Pump (CCHP) Income Eligible Act 151	$10,582	$106,046	($95,464)	$97.94	($883.52)
Heat Pump Water Heater	$23,275	$170	$23,105	$33.84	$33.60
Whole Building Heat Pump (WBHP) - Air to Water - Residential	$18,608	$96	$18,511	$23.38	$23.26
Whole Building Heat Pump (WBHP) - Ducted - Commercial	$15,421	$2,825	$12,596	$27.94	$22.82
Whole Building Heat Pump (WBHP) - Ducted - Residential	$15,606	$2,825	$12,781	$19.66	$16.11
Lawnmower Commercial Electric Push	$216	$2,825	($2,609)	$10.20	($123.06)
Lawnmower Commercial Ride-On	$6,263	$1,910	$4,352	$18.20	$12.65
Lawnmower Residential Electric Push	$254	$1,412	($1,158)	$45.41	($206.82)

2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Lawnmower Residential Ride-On	$527	$1,412	($885)	$14.81	($24.87)
Smart Thermostat	$1,089	$1,412	($324)	$9.35	($2.78)
Yard Care Commercial Chainsaws	$137	$1,412	($1,276)	$8.91	($83.11)
Yard Care Commercial Trimmers, Edgers, and Cultivators	$137	$955	($818)	$8.78	($52.45)
Yard Care Residential Chainsaws	$519	$4,649	($4,130)	$20.60	($163.90)
Yard Care Residential Trimmers, Edgers, and Cultivators	$389	$4,649	($4,260)	$20.60	($225.40)
Electric Bike	$3,127	$4,649	($1,522)	$18.78	($9.14)
Electric Vehicle (New All Electric)	$30,769	$4,649	$26,119	$30.56	$25.94
Electric Vehicle (New All Electric - Low Income Adder)	$14,256	$4,649	$9,607	$42.48	$28.63
Electric Vehicle Charging Stations (Level 2 Public)	$424	$4,649	($4,225)	$13.41	($133.58)
Electric Vehicle Charging Stations (Level 2 Workplace)	$539	$1,327	($789)	$10.67	($15.63)
Electric Forklift (New)	$2,572	$1,327	$1,245	$27.20	$13.17
Electric Golf Cart (New)	$513	$1,327	($815)	$30.53	($48.48)

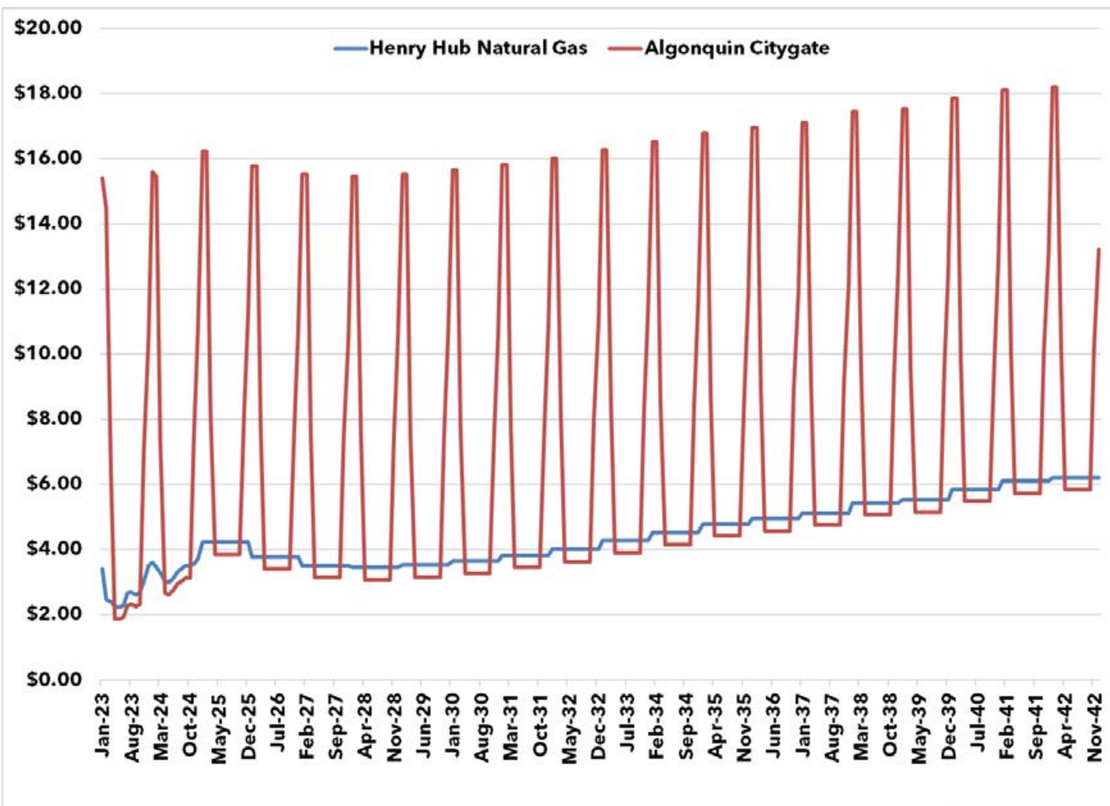
2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Electric Vehicle (New Plug-in Hybrid)	$10,394	$1,327	$9,067	$20.12	$17.55
Electric Vehicle (New Plug-in Hybrid - Low Income Adder)	$7,358	$1,327	$6,030	$35.61	$29.18
Electric Vehicle (Used All Electric)	$5,128	$1,327	$3,801	$30.56	$22.65
Electric Vehicle (Used Plug-in Hybrid)	$1,299	$552	$747	$20.13	$11.57
Custom Projects	TBD		TBD	TBD	TBD
	$252,412	**$317,360**	**($64,948)**	**$25**	**($4)**

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.

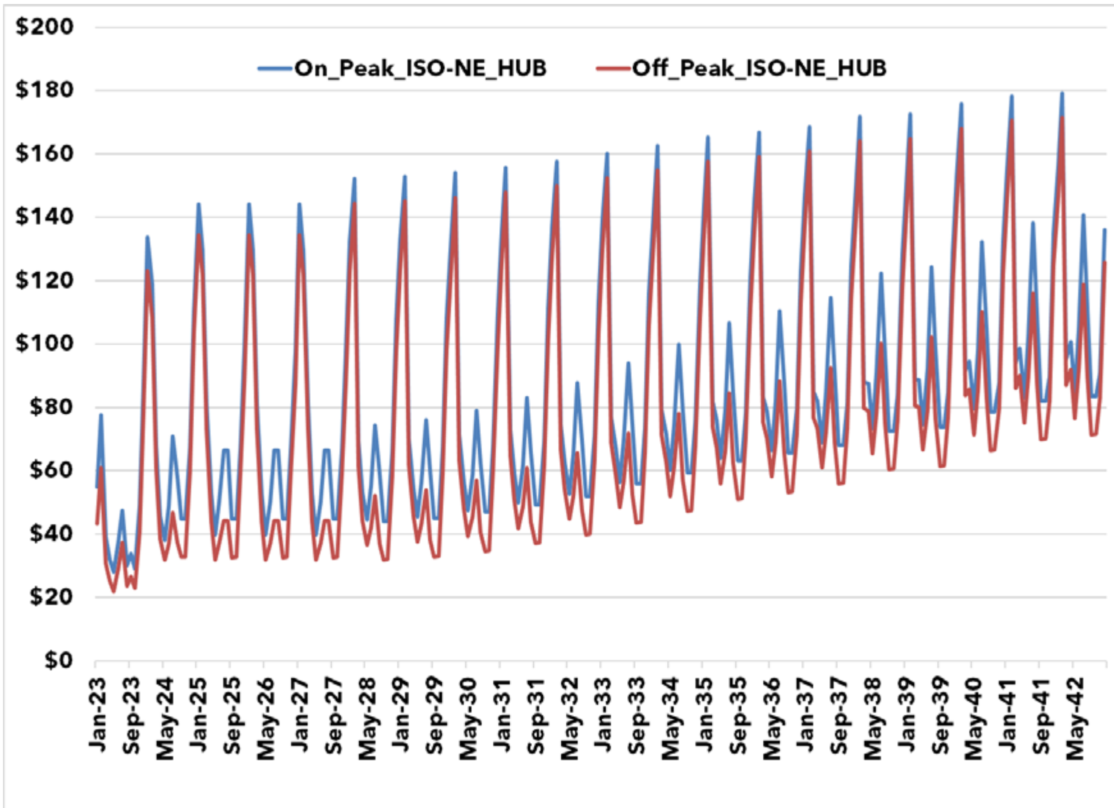
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

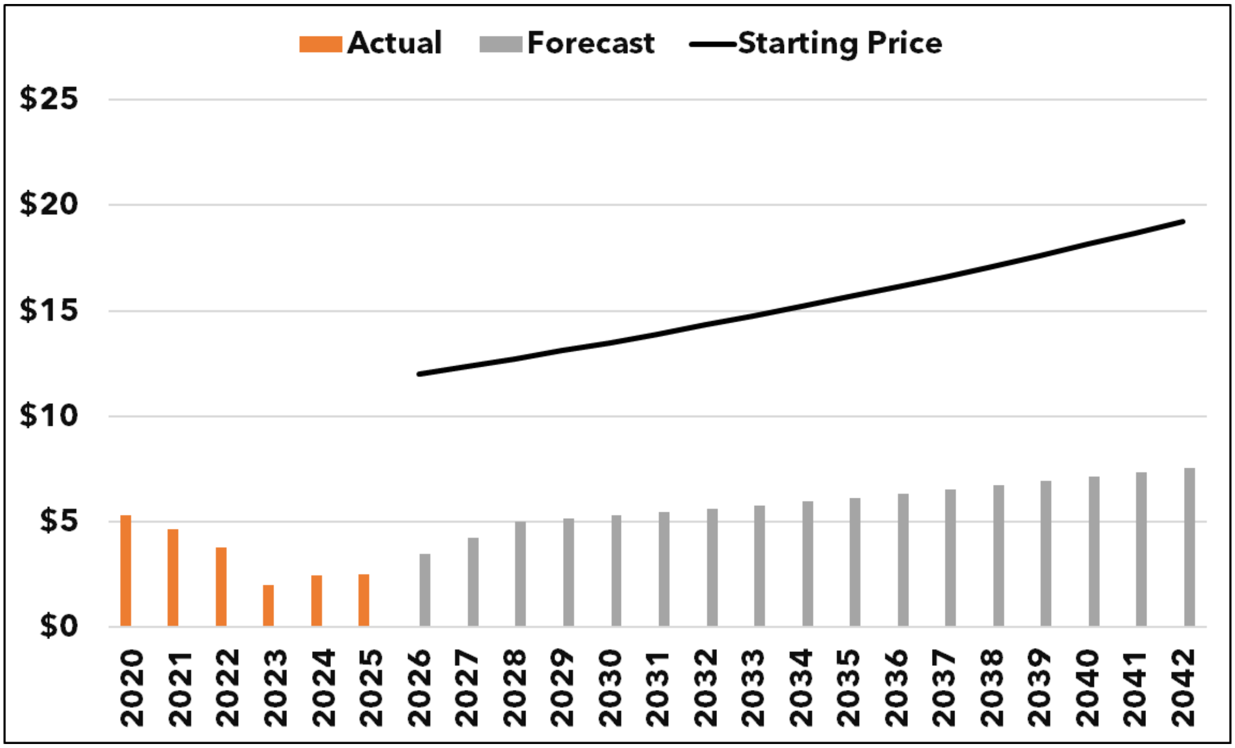


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of MW&L's load and resources.

CAPACITY PRICING

The capacity price forecast starts at $4.66/kW-month, which is the average of the last eight 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)



Morrisville Water and Light 2018

Original

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	Morrisville Water and Light
Calendar year report covers	2018
Contact person	Craig Myotte
Phone number	888-3348
Number of customers	4,179

System average interruption frequency index (SAIFI) = 2.2
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.5
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	127	16,219
2	**Weather**	1	8
3	**Company initiated outage**	3	3,683
4	**Equipment failure**	21	967
5	**Operator error**	0	0
6	**Accidents**	5	1,692
7	**Animals**	30	418
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	4	174
	Total	191	23,160

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.

Morrisville Water and Light 2018

Revised Calculation - Removed Major Storm Outages of April, May, & November 2018

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Morrisville Water and Light
Calendar year report covers	2018
Contact person	Craig Myotte
Phone number	888-3348
Number of customers	4,179

System average interruption frequency index (SAIFI) = 1.4
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.3
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	55	6,317
2	**Weather**	1	8
3	**Company initiated outage**	3	3,683
4	**Equipment failure**	20	964
5	**Operator error**	0	0
6	**Accidents**	5	1,692
7	**Animals**	30	418
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	4	174
	Total	118	13,256

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.

Morrisville Water and Light 2019

Original

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	Morrisville Water and Light
Calendar year report covers	2019
Contact person	Craig Myotte
Phone number	888-3348
Number of customers	4,179

System average interruption frequency index (SAIFI) = 2.7
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.7
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	66	4,009
2	**Weather**	5	136
3	**Company initiated outage**	6	6,687
4	**Equipment failure**	16	6,326
5	**Operator error**	0	0
6	**Accidents**	10	1,801
7	**Animals**	12	235
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	9	247
	Total	124	19,442

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.

Morrisville Water and Light 2019

Revised--Without Major Storms

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	Morrisville Water and Light
Calendar year report covers	2019
Contact person	Craig Myotte
Phone number	888-3348
Number of customers	4,179

System average interruption frequency index (SAIFI) = 2.5
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.7
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	43	2,157
2	**Weather**	5	136
3	**Company initiated outage**	6	6,687
4	**Equipment failure**	16	6,326
5	**Operator error**	0	0
6	**Accidents**	10	1,801
7	**Animals**	12	235
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	9	247
	Total	101	17,589

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.

Morrisville Water and Light Reliability Report

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 calender year. Electricity Outage Report -- PSB Rule 4.900

Electricity Outage Report -- PSB Rule 4.900

Company: Morrisville Water and Light
Calendar Year: 2020
Contact Person: Penny Jones
Phone Number: (802) 888-3348
Customers Served: 4186

System average interuption frequency index (SAIFI) = Customers out / Customers served	1.08
Customer average interuption duration index (CAIDI) = Customer hours out / Customers out	2.73

Outage Code	# of Outages	Total Hours Out
Accident	4	377.76
Animal	10	98.06
Company initiated	17	645.31
Equipment Failure	7	8095.15
other	2	2.90
Trees	25	2256.13
Unknown	11	297.21
Weather - Wind	27	585.78
Total	103	12358.30

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

Morrisville Water and Light Reliability Report

This report is pursuant to PUC Rule 4.903B. It is to be submitted to the Public Utility Commision and the Department of Public Service no later than 30 days after the end of the calender year. Electricity Outage Report -- PSB Rule 4.900

Electricity Outage Report -- PUC Rule 4.900

Company: Morrisville Water and Light
Calendar Year: 2021
Contact Person: Penny Jones
Phone Number: (802) 888-3348
Customers Served: 4244

System average interuption frequency index	1.73
Customer average interuption duration index	1.41

Outage Code	# of Outages	Total Hours Out
Accident	5	57.76
Animal	11	132.29
Company initiated	11	4809.8
Equipment Failure	19	2148.49
non-utility	2	3.75
Operator Error	3	538.08
other	2	201.36
Trees	38	1542.98
Unknown	6	315.02
Weather - Wind	16	584.24
Total	113	10333.77

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

Morrisville Water and Light Reliability Report

This report is pursuant to PUC Rule 4.903B. It is to be submitted to the Public Utility Commision and the Department of Public Service no later than 30 days after the end of the calender year. Electricity Outage Report -- PSB Rule 4.900

Electricity Outage Report -- PUC Rule 4.900

Company: Morrisville Water and Light
Calendar Year: 2022
Contact Person: Scott Johnstone
Phone Number: (802) 888-3348
Customers Served: 4186

System average interuption frequency index	1.64
Customer average interuption duration index	0.83

Outage Code	# of Outages	Total Hours Out
Accident	1	4.42
Animal	10	152.63
Company initiated	34	655.83
Equipment Failure	13	271.71
non-utility	3	26.6
Operator Error	3	722.15
Trees	37	1818.34
Unknown	15	538.14
Weather - Wind	26	1537.34
Total	142	5727.16

Note: Per PUC Rule 4.903(B)(3),this report must be accompanied by an overall assessment of the system reliability that addresses the areas where most of the outages occur and the cause underlying most outages. Based on this assesment, the utility should describe, for both the long and short terms, appropiate and nessessary,

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

Vermont Public Power Supply Authority

Putting the Public in Power.

www.vppsa.com

P.O. Box 126 • 5195 Waterbury-Stowe Rd. • Waterbury Center, VT 05677 • 802.244.7678 • Fax: 802.244.6889

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:

Meter Interface Units (MIUs)

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.

APPENDIX F: AMI DECISION MAKING PROCESS

Planned AMI

Beginning in 2018, MW&L 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 MW&L. Since MW&L provides both electric and water services, this evaluation covered an AMI implementation for both services. AMI is a major technical and business transition for any utility and provides a platform to improve operational efficiency, reliability, and customer service, including new functionality such as time-of-use or dynamic rate plans for customers, demand response programs, grid management improvements, and greater customer engagement.

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

Table 1: 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. MW&L 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 MW&L provides water service, there is the benefit of adding water metering to the solution, ultimately strengthening an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 2: AMI Readiness Evaluation

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

MW&L expects to benefit from AMI implementation in a number of ways:

- Collection of interval data to support cost of service and innovative rate design
- Offer energy programs for customers to promote beneficial load management

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

In terms of business case, a cost benefit assessment, looking at about 20 areas of potential benefit, spanning field operations, metering and meter operations, billing, and customer and related rate programs was performed. This assessment indicates a positive NPV benefit of more than $969,000, with a positive cost-benefit ratio of 1.52 and a 6.3-year payback, providing MW&L with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of the state funding opportunity. Negotiation of a final contract with Aclara has been recently completed; MW&L is optimistic that it will begin implementation of a new AMI system in early 2024, to be completed no later than 2025.

2022 Long-Term Forecast Report

VILLAGE OF MORRISVILLE WATER & LIGHT DEPARTMENT

VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared For:
VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared By:
ITRON, INC.

20 Park Plaza, 4th Floor, Boston, MA 02116 | (617) 423-7660 | www.itron.com/forecasting

2022 LONG-TERM DEMAND FORECAST SUMMARY – MORRISVILLE

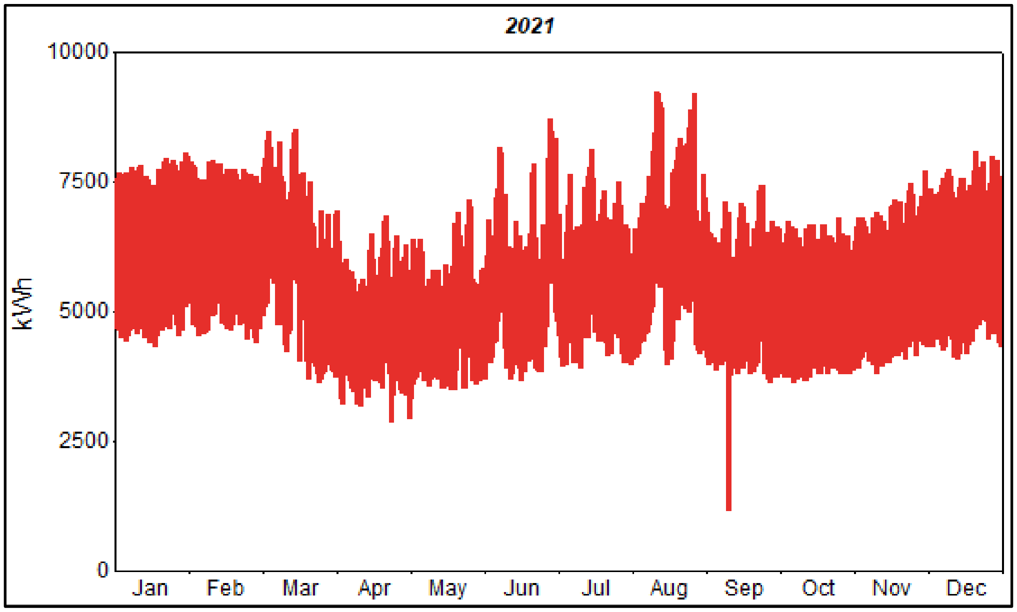
The Village of Morrisville Water and Light Department (Morrisville) serves approximately 3,600 residential customers and 650 commercial customers. Sales are split equally across the two customer classes. Morrisville has experienced relatively strong residential customer growth averaging 0.9% annually over the last ten years. Morrisville is one of a few state utilities that has seen positive sales growth; Total 2021 sales are 46,121 MWh compared with sales of 44,581 MWh in 2011. COVID-19 had a muted impact on sales as loss in commercial sales was mitigated by increase in residential sales. Table 1 shows historical residential customers and class sales.

TABLE 1: MORRISVILLE HISTORICAL CALENDARIZED SALES 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	20,358		3,285		6,198		24,223		44,581	
2012	20,357	0.0%	3,288	0.1%	6,192	-0.1%	23,994	-0.9%	44,351	-0.5%
2013	20,869	2.5%	3,309	0.6%	6,308	1.9%	23,788	-0.9%	44,657	0.7%
2014	21,263	1.9%	3,339	0.9%	6,368	1.0%	23,258	-2.2%	44,522	-0.3%
2015	21,412	0.7%	3,365	0.8%	6,363	-0.1%	23,746	2.1%	45,158	1.4%
2016	20,852	-2.6%	3,391	0.8%	6,149	-3.4%	23,619	-0.5%	44,471	-1.5%
2017	20,812	-0.2%	3,408	0.5%	6,106	-0.7%	22,689	-3.9%	43,501	-2.2%
2018	21,605	3.8%	3,441	1.0%	6,279	2.8%	24,234	6.8%	45,839	5.4%
2019	21,731	0.6%	3,498	1.7%	6,212	-1.1%	23,981	-1.0%	45,711	-0.3%
2020	22,911	5.4%	3,549	1.4%	6,456	3.9%	23,075	-3.8%	45,986	0.6%
2021	22,899	-0.1%	3,593	1.2%	6,374	-1.3%	23,222	0.6%	46,121	0.3%
11-21		**1.2%**		**0.9%**		**0.3%**		**-0.4%**		**0.4%**

Given the relatively large commercial sales base, Morrisville has been mostly summer peaking with a system peak around 9.2 MW. Figure 1 shows the 2021 system hourly load.

FIGURE 1: MORRISVILLE SYSTEM LOAD 2021



Forecast Approach

The Morrisville long-term forecast is based on a bottom-up modeling framework where the forecast starts at the revenue-class (e.g., residential, commercial, and industrial) with heating, cooling, and base-use sales derived from the sales models used to drive system energy and peak demand. The system energy is based on the historical relationship between sales and monthly system delivered energy while baseline peak demand is derived from end-use estimates of heating, cooling, and non-weather sensitive loads; the peak end-use model drivers are derived from the class sales models. This approach is used for all VPPSA members, GMP, Burlington Electric, and VELCO. A detailed description of the modeling approach is included in the 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For Morrisville, this includes residential, small and large commercial, industrial, and other (other is primarily street lighting and is relatively small). Models are estimated using monthly linear regression models with historical billed sales and customer counts from January 2011 to December 2021. Model estimated coefficients, statistics and actual and predicted and results are included in APPENDIX A.

The baseline forecast captures expected load growth before adjustments for new PV adoptions, electric vehicle (EV), and cold climate heat pumps (CCHP). Baseline sales are driven by customer growth projections, state economic forecasts, end-use efficiency (both due to standards and state EE program activity) and saturation projections and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model integrates end-use saturation and efficiency trends that change slowly over time with variables that impact month-to-month sales variation and capture economic growth; this includes temperatures (HDD and CDD), economic conditions (household income, employment, and state output), and demographic trends (population, number of households, household size).

Economic Drivers

Historical and forecasted economic data is provided by Moody's Analytics. Forecasts are based on the January 2022 economic forecast. Model inputs include number of households, household income, gross state product, and employment. Economic data is provided in 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

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 sq. ft.) for Vermont are like those of New England. The forecast is further adjusted for state energy efficiency program savings derived from the current state Demand Resource Plan (DRP). Morrisville accounts for 1.1% of state residential sales and 1.0% of commercial sales.

Weather

Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are based on Burlington International Airport temperature data. Since 1970, average temperatures have been increasing 0.08 degrees per year (0.8 degrees per decade). This is reflected in the number of cooling degree-days (CDD) which are increasing 1.3% per year on a relatively low base and decrease in heating degree-days (HDD) of 0.3% per year. We assume average temperature continues to increase at the current rate through the forecast period with decline in HDD contributing to lower heating requirements and increase in CDD to higher cooling requirements.

COVID-19

The "work at home" and closure of most retail businesses impacted sales starting in late March 2020. The commercial sector saw a significant decline in sales while residential a large increase. Through 2021 sales began to normalize as more people went back to work. While there has been continued *sales normalization*, recent data from Burlington Electric and GMP has shown the trend through mid-July 2022 has slowed. We are likely seeing permanent structural change as many businesses transition to hybrid work environment (part-time at home and part-time at the office) and increasing number of workers that are and will continue to be working on a fully remote basis. COVID residential and nonresidential model variables are based on Vermont Google mobility data through the end of 2021. The mobility data measures the cellphone call volume variance from March 2020 (the month before COVID's load impact). In residential call volume increased and in the non-residential workplaces call volume decreased. For the forecast we trend the mobility variables back to base value in March 2020. Starting in 2023 we hold the COVID variables at 90% of pre-COVID level to capture what we believe will be some permanent shift in residential average use (up slightly from pre-COVID levels) and commercial sales (down slightly from pre-COVID levels).

A detailed description of the baseline model structure, and model inputs are included in 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Results

We expect flat baseline sales growth as customer growth trends back towards state household growth and energy efficiency holds customer usage in check. Baseline sales are expected to reach 45,597 MWh in 2032 compared with expected year-end 2022 sales of 46,098 MWh representing a 1.1% decrease. Table 2 shows Morrisville baseline customer and sales forecast.

TABLE 2: MORRISVILLE 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	22,553		3,641		6,195		23,545		46,098	
2023	22,319	-1.0%	3,681	1.1%	6,063	-2.1%	23,711	0.7%	46,030	-0.1%
2024	22,321	0.0%	3,712	0.9%	6,013	-0.8%	23,739	0.1%	46,061	0.1%
2025	22,185	-0.6%	3,739	0.7%	5,933	-1.3%	23,653	-0.4%	45,838	-0.5%
2026	22,178	0.0%	3,764	0.7%	5,892	-0.7%	23,551	-0.4%	45,728	-0.2%
2027	22,142	-0.2%	3,785	0.6%	5,849	-0.7%	23,444	-0.5%	45,586	-0.3%
2028	22,214	0.3%	3,806	0.5%	5,837	-0.2%	23,379	-0.3%	45,593	0.0%
2029	22,271	0.3%	3,825	0.5%	5,823	-0.2%	23,271	-0.5%	45,543	-0.1%
2030	22,364	0.4%	3,843	0.5%	5,819	-0.1%	23,180	-0.4%	45,543	0.0%
2031	22,453	0.4%	3,860	0.4%	5,817	0.0%	23,074	-0.5%	45,527	0.0%
2032	22,582	0.6%	3,874	0.4%	5,829	0.2%	23,015	-0.3%	45,597	0.2%
2033	22,579	0.0%	3,886	0.3%	5,810	-0.3%	22,885	-0.6%	45,464	-0.3%
2034	22,615	0.2%	3,895	0.2%	5,805	-0.1%	22,792	-0.4%	45,407	-0.1%
2035	22,678	0.3%	3,904	0.2%	5,809	0.1%	22,701	-0.4%	45,379	-0.1%
2036	22,796	0.5%	3,912	0.2%	5,827	0.3%	22,669	-0.1%	45,465	0.2%
2037	22,790	0.0%	3,917	0.1%	5,818	-0.2%	22,559	-0.5%	45,349	-0.3%
2038	22,794	0.0%	3,921	0.1%	5,814	-0.1%	22,487	-0.3%	45,281	-0.2%
2039	22,795	0.0%	3,923	0.1%	5,811	-0.1%	22,410	-0.3%	45,205	-0.2%
2040	22,854	0.3%	3,925	0.0%	5,823	0.2%	22,338	-0.3%	45,192	0.0%
2041	22,835	-0.1%	3,925	0.0%	5,818	-0.1%	22,203	-0.6%	45,038	-0.3%
2042	22,867	0.1%	3,923	0.0%	5,828	0.2%	22,110	-0.4%	44,976	-0.1%
22-32		0.0%		0.6%		-0.6%		-0.2%		-0.1%
32-42		0.1%		0.1%		0.0%		-0.4%		-0.1%

Adjusted Forecast

The baseline forecast is adjusted for new behind-the-meter (BTM) solar projections starting in 2022, electric vehicles, and cold climate heat pumps (CCHP). Future electricity sales and demand growth will largely be driven by these technologies that are being promoted as part of the state's electrification programs designed to reduce 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 with rebates, low-interest loans, and building out electric vehicle infrastructure. Expected increase in behind the meter solar adoption (PV) mitigates some of the long-term energy 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. We are beginning work to update these assumptions as result of the recently passed *Vermont Climate Action Plan*.

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

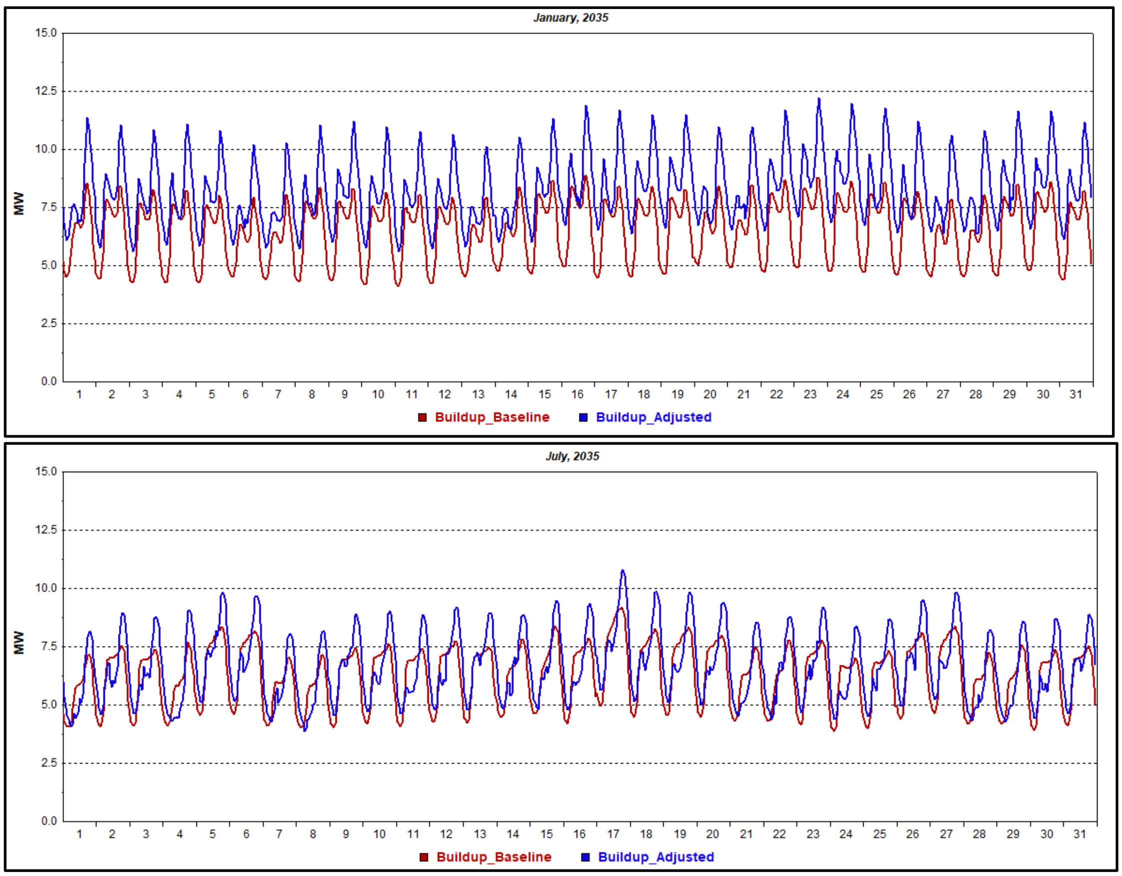
TABLE 3: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	25	350	64
2023	58	783	135
2024	101	1,215	213
2025	158	1,487	297
2026	231	1,614	388
2027	325	1,746	486
2028	444	1,824	591
2029	593	1,852	703
2030	773	1,913	810
2031	987	1,992	903
2032	1,232	2,085	992
2033	1,501	2,116	1,077
2034	1,782	2,155	1,162
2035	2,063	2,176	1,248
2036	2,326	2,212	1,336
2037	2,559	2,231	1,425
2038	2,755	2,264	1,514
2039	2,911	2,281	1,604
2040	3,032	2,311	1,694
2041	3,116	2,336	1,781
2042	3,176	2,362	1,869

Technology annual energy forecasts are estimated by combining technology characteristics such as average historical load profile, heating and cooling unit energy consumption, average miles driven, and technology efficiency trends with unit forecasts. Hourly (8,760) technology forecasts are then generated by combining technology annual energy forecast with technology hourly profiles that reflect seasonality, solar load patterns, and expected HDD and CDD.

The system adjusted hourly load forecast is calculated by subtracting PV hourly load forecast and adding EV and CCHP load forecasts to the baseline hourly load forecast. Figure 2 shows the baseline and adjusted hourly load forecast for January and July 2035.

FIGURE 2: BASELINE AND ADJUSTED HOURLY LOAD FORECAST



By 2035, EVs and CCHP add significant load. The summer adjustments add 1.7 MW to baseline demand forecast and in the winter 3.4 MW. The winter load adjustments are much higher than summer adjustments as both EV charging and CCHP winter peak hour load impacts are higher. Adjusted energy is calculated by adding the hourly adjusted load forecasts and winter and summer peak demands are derived by finding the highest hourly load in each season and year. Table 4 shows the adjusted energy and demand forecasts.

TABLE 4: MORRISVILLE ENERGY FORECAST (MWH)

Energy and Peak										
Year	Energy (MWh)	Chg	Energy WN (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2011	50,325		50,426		8.97		7/21/11 3:00 PM	8.38		1/24/11 5:00 PM
2012	49,281	-2.1%	49,551	-1.7%	8.43	-6.0%	6/21/12 2:00 PM	8.32	-0.7%	1/3/12 5:00 PM
2013	49,925	1.3%	49,956	0.8%	9.16	8.6%	7/19/13 3:00 PM	8.38	0.7%	12/17/13 5:00 PM
2014	50,092	0.3%	50,045	0.2%	8.94	-2.4%	7/2/14 12:00 PM	9.45	12.8%	12/27/14 5:00 PM
2015	49,809	-0.6%	49,455	-1.2%	8.96	0.2%	8/19/15 1:00 PM	8.38	-11.3%	1/8/15 5:00 PM
2016	48,967	-1.7%	48,919	-1.1%	8.64	-3.6%	8/11/16 12:00 PM	7.92	-5.5%	12/20/16 6:00 PM
2017	48,345	-1.3%	48,649	-0.5%	7.90	-8.6%	8/22/17 3:00 PM	8.82	11.3%	12/28/17 5:00 PM
2018	49,487	2.4%	49,050	0.8%	9.14	15.7%	7/2/18 2:00 PM	8.50	-3.6%	1/6/18 5:00 PM
2019	48,855	-1.3%	48,788	-0.5%	8.67	-5.2%	7/30/19 4:00 PM	8.51	0.0%	1/21/19 5:00 PM
2020	49,656	1.6%	49,714	1.9%	9.09	4.8%	7/27/20 3:00 PM	8.31	-2.3%	12/16/20 5:00 PM
2021	49,354	-0.6%	49,465	-0.5%	9.18	1.1%	8/11/21 6:00 PM	8.03	-3.3%	12/20/21 5:00 PM
2022	48,904	-0.9%			8.91	-3.0%	7/19/22 6:00 PM	8.65	7.7%	1/18/22 5:00 PM
2023	48,511	-0.8%			8.98	0.8%	7/18/23 6:00 PM	8.76	1.3%	1/17/23 6:00 PM
2024	48,250	-0.5%			9.02	0.4%	7/16/24 6:00 PM	8.92	1.8%	1/16/24 6:00 PM
2025	48,014	-0.5%			9.07	0.5%	7/15/25 6:00 PM	9.07	1.7%	1/21/25 6:00 PM
2026	48,172	0.3%			9.16	1.0%	7/21/26 6:00 PM	9.27	2.2%	1/20/26 6:00 PM
2027	48,366	0.4%			9.25	1.0%	7/20/27 6:00 PM	9.50	2.4%	1/19/27 6:00 PM
2028	48,898	1.1%			9.38	1.3%	7/18/28 6:00 PM	9.77	2.9%	1/18/28 6:00 PM
2029	49,565	1.4%			9.51	1.4%	7/17/29 6:00 PM	9.99	2.2%	1/23/29 6:00 PM
2030	50,335	1.6%			9.70	2.0%	7/16/30 7:00 PM	10.34	3.5%	1/22/30 6:00 PM
2031	51,152	1.6%			9.89	1.9%	7/15/31 7:00 PM	10.69	3.4%	1/21/31 6:00 PM
2032	52,133	1.9%			10.10	2.2%	7/20/32 7:00 PM	11.07	3.6%	1/20/32 6:00 PM
2033	53,073	1.8%			10.32	2.1%	7/19/33 7:00 PM	11.46	3.6%	1/18/33 6:00 PM
2034	54,124	2.0%			10.57	2.4%	7/18/34 6:00 PM	11.78	2.7%	1/24/34 6:00 PM
2035	55,232	2.0%			10.78	2.1%	7/17/35 7:00 PM	12.18	3.4%	1/23/35 6:00 PM
2036	56,378	2.1%			11.04	2.4%	7/15/36 7:00 PM	12.59	3.3%	1/22/36 6:00 PM
2037	57,241	1.5%			11.22	1.6%	7/21/37 7:00 PM	12.96	3.0%	1/20/37 6:00 PM
2038	57,998	1.3%			11.40	1.6%	7/20/38 7:00 PM	13.30	2.6%	1/19/38 6:00 PM
2039	58,632	1.1%			11.55	1.3%	7/19/39 7:00 PM	13.59	2.2%	1/18/39 6:00 PM
2040	59,182	0.9%			11.69	1.2%	7/17/40 7:00 PM	13.73	1.1%	1/24/40 6:00 PM
2041	59,459	0.5%			11.79	0.8%	7/16/41 7:00 PM	13.97	1.7%	1/22/41 6:00 PM
2042	59,758	0.5%			11.87	0.7%	7/15/42 7:00 PM	14.17	1.4%	1/21/42 6:00 PM
11-21		**-0.2%**		**-0.2%**		**0.5%**			**-0.2%**	
22-42		**1.0%**				**1.4%**			**2.5%**	

Projected EV, CCHP, and PVs have a significant impact on load; over the next twenty years, delivered energy is expected to average 1.0% annual growth. This compares with baseline annual sales decline of 0.1%. Winter adjusted peak averages 2.5% annual demand growth and summer 1.4% average annual growth. Morrisville becomes a winter peaking utility by 2025 as increasing EV and CCHP adoption shifts both the timing and season of the peak.

Table 5 and Table 6 summarizes the demand forecast by base load and technologies.

TABLE 5: MORRISVILLE SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	8.89		0.02	-0.02	0.02	8.91	
2023	8.93	0.4%	0.03	-0.02	0.04	8.98	0.8%
2024	8.97	0.4%	0.06	-0.07	0.07	9.02	0.4%
2025	8.97	0.0%	0.10	-0.09	0.09	9.07	0.5%
2026	8.99	0.2%	0.14	-0.08	0.12	9.16	1.0%
2027	9.00	0.1%	0.20	-0.09	0.15	9.25	1.0%
2028	9.03	0.3%	0.27	-0.10	0.18	9.38	1.3%
2029	9.04	0.2%	0.36	-0.11	0.21	9.51	1.4%
2030	8.96	-0.9%	0.50	0.00	0.24	9.70	2.0%
2031	8.99	0.3%	0.64	-0.01	0.26	9.89	1.9%
2032	9.01	0.3%	0.80	0.00	0.29	10.10	2.2%
2033	9.03	0.1%	0.98	0.00	0.31	10.32	2.1%
2034	9.18	1.8%	1.09	-0.06	0.35	10.57	2.4%
2035	9.07	-1.2%	1.35	-0.01	0.36	10.78	2.1%
2036	9.13	0.6%	1.52	0.00	0.39	11.04	2.4%
2037	9.12	0.0%	1.68	0.00	0.41	11.22	1.6%
2038	9.15	0.3%	1.81	0.00	0.44	11.40	1.6%
2039	9.18	0.3%	1.92	0.00	0.46	11.55	1.3%
2040	9.21	0.4%	1.99	0.00	0.49	11.69	1.2%
2041	9.22	0.1%	2.05	0.00	0.52	11.79	0.8%
2042	9.25	0.3%	2.09	-0.01	0.54	11.87	0.7%
22-42		**0.2%**					**1.4%**

TABLE 6: MORRISVILLE WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	8.56		0.02	0.00	0.07	8.65	
2023	8.59	0.4%	0.05	0.00	0.11	8.76	1.3%
2024	8.64	0.6%	0.10	0.00	0.18	8.92	1.8%
2025	8.57	-0.8%	0.15	0.00	0.35	9.07	1.7%
2026	8.60	0.3%	0.22	0.00	0.45	9.27	2.2%
2027	8.62	0.3%	0.31	0.00	0.57	9.50	2.4%
2028	8.66	0.5%	0.42	0.00	0.68	9.77	2.9%
2029	8.60	-0.7%	0.57	0.00	0.82	9.99	2.2%
2030	8.65	0.6%	0.74	0.00	0.94	10.34	3.5%
2031	8.69	0.4%	0.95	0.00	1.05	10.69	3.4%
2032	8.75	0.6%	1.18	0.00	1.15	11.07	3.6%
2033	8.77	0.3%	1.44	0.00	1.25	11.46	3.6%
2034	8.71	-0.7%	1.72	0.00	1.35	11.78	2.7%
2035	8.75	0.4%	1.99	0.00	1.45	12.18	3.4%
2036	8.81	0.7%	2.24	0.00	1.54	12.59	3.3%
2037	8.84	0.3%	2.48	0.00	1.65	12.96	3.0%
2038	8.88	0.5%	2.67	0.00	1.75	13.30	2.6%
2039	8.91	0.4%	2.82	0.00	1.86	13.59	2.2%
2040	8.86	-0.6%	2.93	0.00	1.95	13.73	1.1%
2041	8.88	0.3%	3.02	0.00	2.07	13.97	1.7%
2042	8.92	0.4%	3.07	0.00	2.18	14.17	1.4%
22-42		**0.2%**					**2.5%**

Baseline summer system peak averages 0.2% growth per year largely driven by air conditioning saturation projections. Expected PV adoption negatively impacts energy growth but has a limited to no impact on peak demand as the system peak has been moved out to later hours from past solar adoption. Most of the load growth is driven by EV charging and CCHP.

2022 LONG-TERM FORECAST MODEL OVERVIEW

INTRODUCTION

Vermont Public Power Supply Authority (VPPSA) serves 11 members located across Vermont. Combined VPPSA members serve 50 communities and over 30,000 customers.

The VPPSA members include:

- Morrisville
- Enosburg
- Hardwick
- Morrisville
- Johnson
- Ludlow
- Lyndonville
- Morrisville
- Northfield
- Morrisville
- Swanton

Long-term sales, energy, and demand forecasts have been developed for each member.

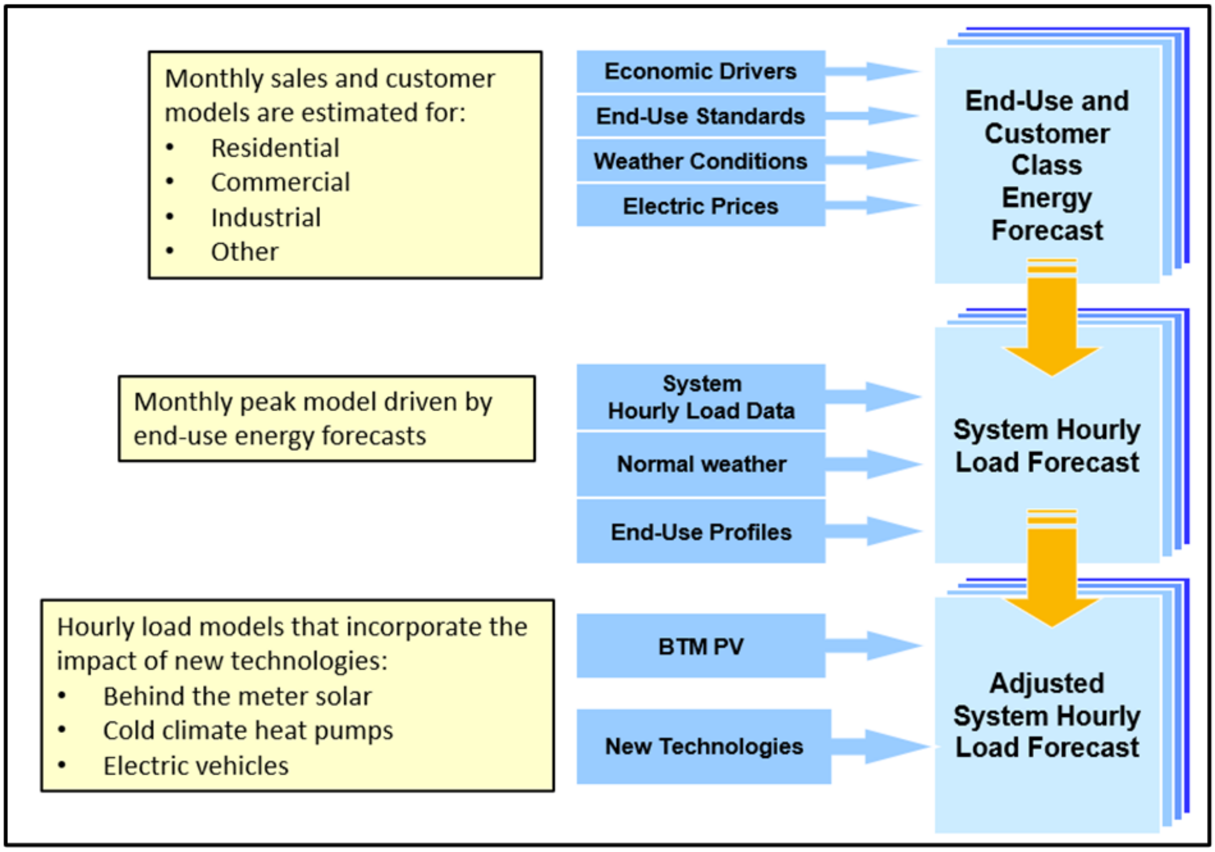
Forecast includes:

- Residential, commercial, industrial, and other classification sales and customers
- Baseline energy and peak demand
- Adjusted energy and peak demand. Adjusted for the impacts of new technologies including electric vehicles, photovoltaic solar, and cold-climate heat pumps.

FORECAST METHOD

The long-term forecasts are based on a bottom-up approach were baseline energy, demand, and hourly load is first developed from underlying customer class heating, cooling, and base-use energy requirements. The baseline hourly load forecast is then adjusted for the long-term load impacts of electric vehicles (EV's), solar (PV's), and cold-climate heat pumps (CCHP). Figure 3 shows the general forecasting approach.

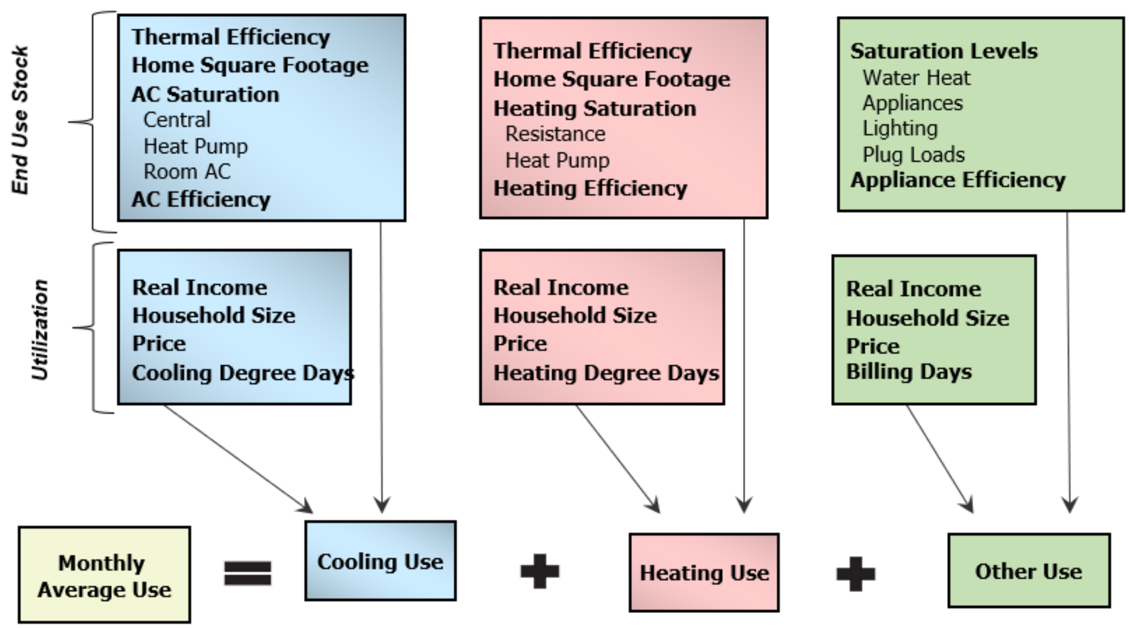
FIGURE 3: FORECASTING FRAMEWORK



Customer Class Sales Forecast

The forecast process starts with estimating sales models for residential, small commercial, large commercial, industrial, and other (mostly street lighting) classes. The residential forecast is derived as the product of the residential average use and customer forecast. Commercial, industrial, and other revenue classes are estimated as total sales models. Models are estimated with monthly billed sales data from January 2011 through December 2021 using linear regression. Models are used to forecast sales and customers based on projected demographic and economic growth, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), and trended normal heating degree-days (HDD) and cooling degree-days (CDD). Where supported by the data, models are estimated using a modeling structure called a Statistically Adjusted End-Use (SAE) model. The SAE model specification integrates the forecast drivers into three primary model variables that include heating (XHeat), cooling (XCool), and other uses (XOther) variables. Figure 4 shows the SAE model specification.

FIGURE 4: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL

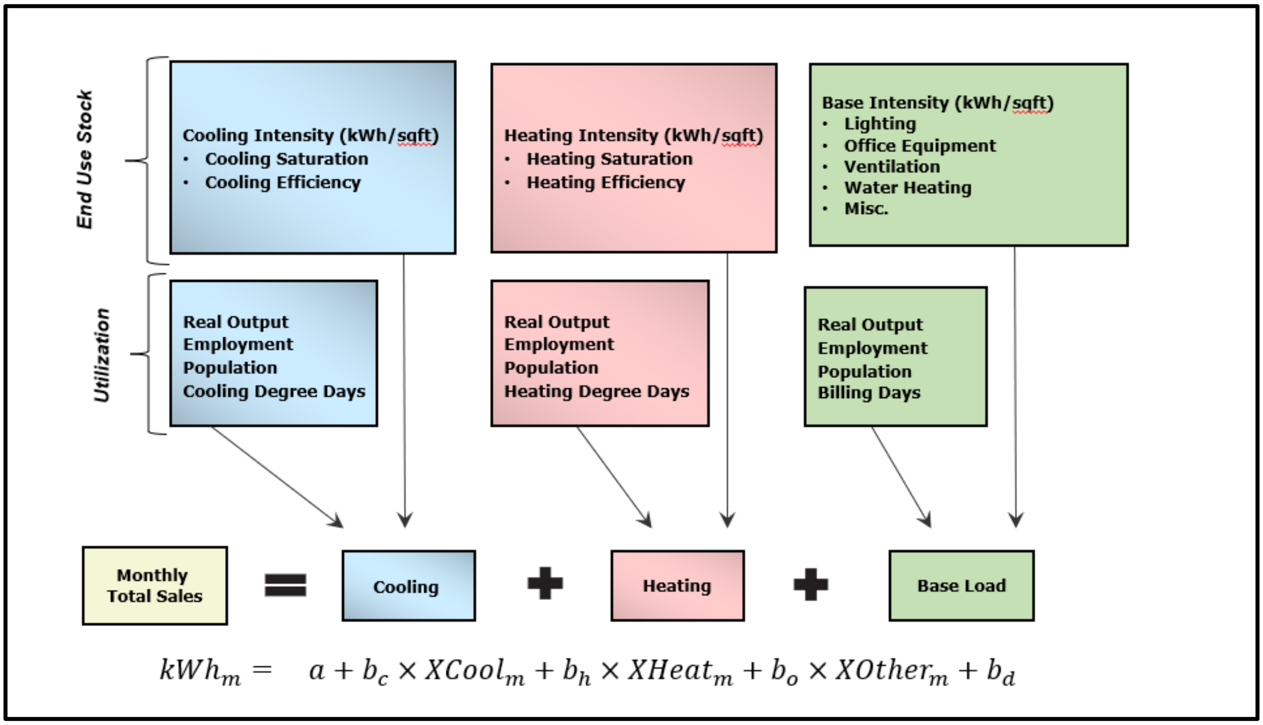


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Residential forecast is the product of the customer forecast and average use forecast. Average use is defined as the sum of average monthly cooling (XCool), heating (XHeat), and other non-weather energy use (XOther). Historical EE estimates are also included in the model to account for any state efficiency savings that are not captured on the primary end-use variables. In most models the variable proved to be statistically insignificant largely as the number of customers and noise in the billing data proved to be too few to pick up much of an impact. A monthly average use regression model is used to estimate the coefficients a, b_c, b_h, and b_o,, and b_e which effectively *statistically adjust* the end-use model variables to actual customer usage. End-use sales estimates are then derived by combining the estimated model coefficients with the model variables (XCool, XHeat, and XOther) for normal weather conditions. The specification is theoretically strong and appropriately captures the impact and interaction of structural model variables (e.g., end-use saturation, efficiency, and thermal shell integrity) with monthly utilization variables – weather conditions, household size, and household income.

A similar SAE model specification is used for the commercial customer classes. Figure 5 shows the commercial model specification.

FIGURE 5: COMMERCIAL SAE MODEL



In the commercial model end-use energy intensities are expressed on a kWh per square foot basis. Intensities for cooling, heating, and base-use are derived from EIA's Annual Energy Outlook for the New England Census Division. Annual end-use intensities are combined with monthly utilization variables that include monthly HDD and CDD, and constructed economic driver based that incorporates state economic output, employment, and population. Model variables are used in estimating monthly sales models. Commercial end-use energy requirements are derived as the product of the estimated model coefficient and initial end-use energy estimates (XCool, XHeat, and XOther).

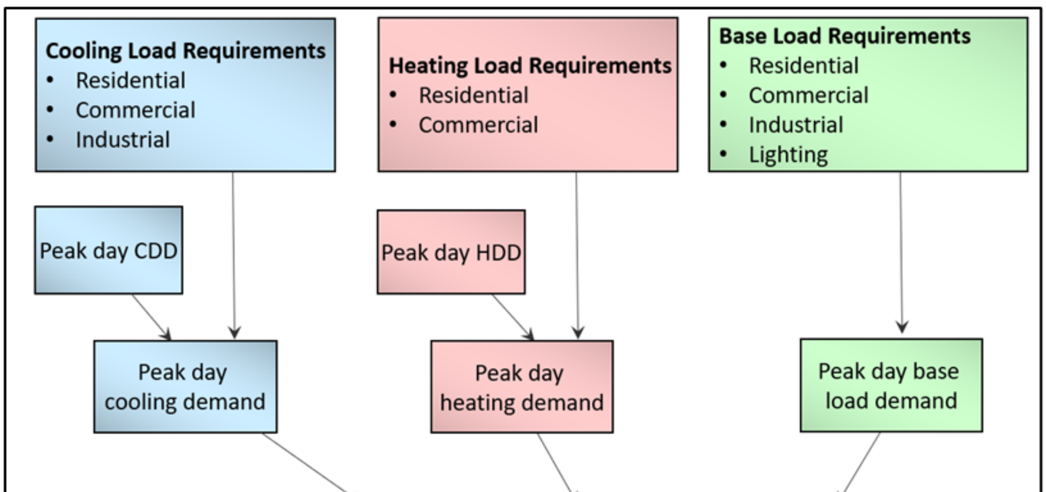
For many of the municipalities the larges C&I customer class is dominated by a few companies. The is often significant variation in month-to-month sales making it difficult to fit with an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is also true for the *other* customer class that is generally street lighting and municipal own use.

Baseline Energy, Peak, and Hourly Load Forecast

The baseline energy forecast is derived from the customer-class sales forecasts. For most members, the energy forecast is derived by aggregating the customer class sales forecasts and adjusting for line losses. In some case where billed sales data (used in estimating class sales) are too noisy due to the billing process, separate monthly energy regression models are estimated where the total sales forecast is the primary driver.

Monthly peak regression models are estimated based on underlying heating, cooling, and base-use loads derived from the customer class sales models. Heating and cooling load requirements are combined with peak-producing weather to generate peak-day heating and cooling variables; the impact of peak-day temperatures changes over time with changes in heating and cooling load requirements. In general baseline heating requirements are declining as traditional resistant heat saturation falls and cooling requirements are increasing with increasing air conditioning saturation. The expected growth due to CCHP program turns around the baseline decline in heating load and adds to cooling demand growth. Figure 6 shows the baseline peak demand model.

FIGURE 6: BASELINE PEAK MODEL

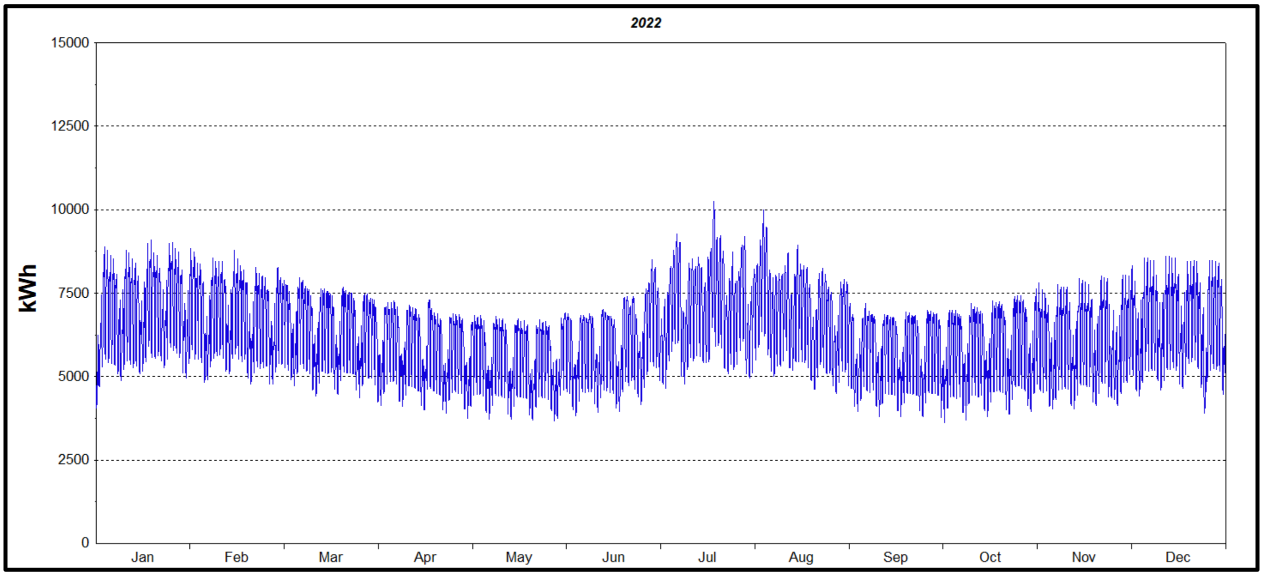


$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_b \times PkBase_m + e_m$$

The peak model is estimated using linear regression that relates the monthly peak to peak-day CDD and HDD, combined with cooling, heating, and base load requirements at time of peak.

A baseline hourly load profile is derived from historical hourly system loads. Models are designed to capture expected hourly loads for typical weather conditions, day of the week, season, and holidays. Figure 7 shows the baseline profile for Swanton.

FIGURE 7: SWANTON HOURLY BASELINE PROFILE



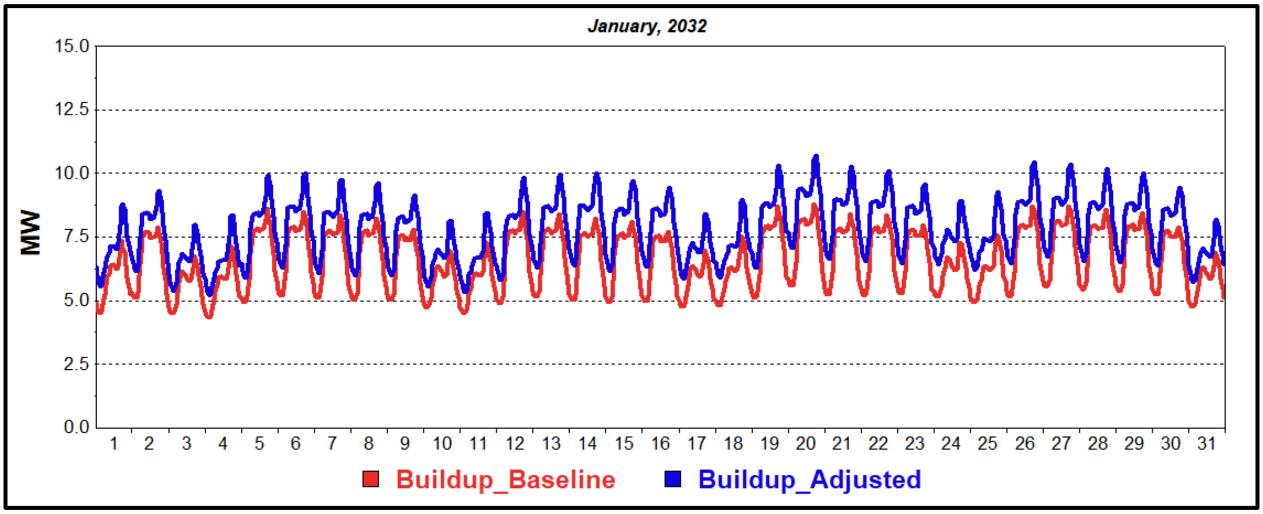
The baseline profile is constant over the estimation period. The baseline hourly load forecast is then derived by combining the baseline energy and peak forecast with the profile. Increase in energy requirements and peak demand lift the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

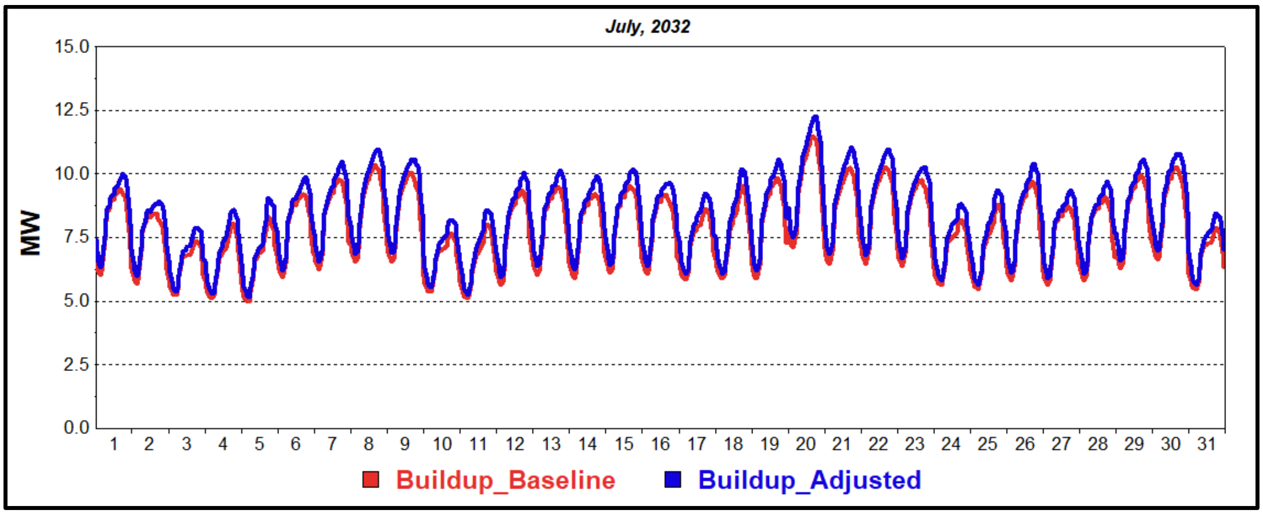
Adjusted Load Forecast

For the most part, baseline loads are either flat or declining as efficiency gains have outweighed customer and economic growth. The long-term peak demand drivers are expected market penetration of CCHP and EV purchases. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV market penetration is projected to continue to increase, capacity projections slow from current pace and have minimum impact on peak demand; PV capacity has already shifted peaks into the later summer hours and has no impact on winter peak demand.

The expected increase in PV adoption, CCHP, and EVs reshape system load over time and as a result the timing and level of peak demand. Incremental PV energy savings, and new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast. Figure 8 compares the Swanton baseline and hourly load forecast for 2032.

FIGURE 8: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)





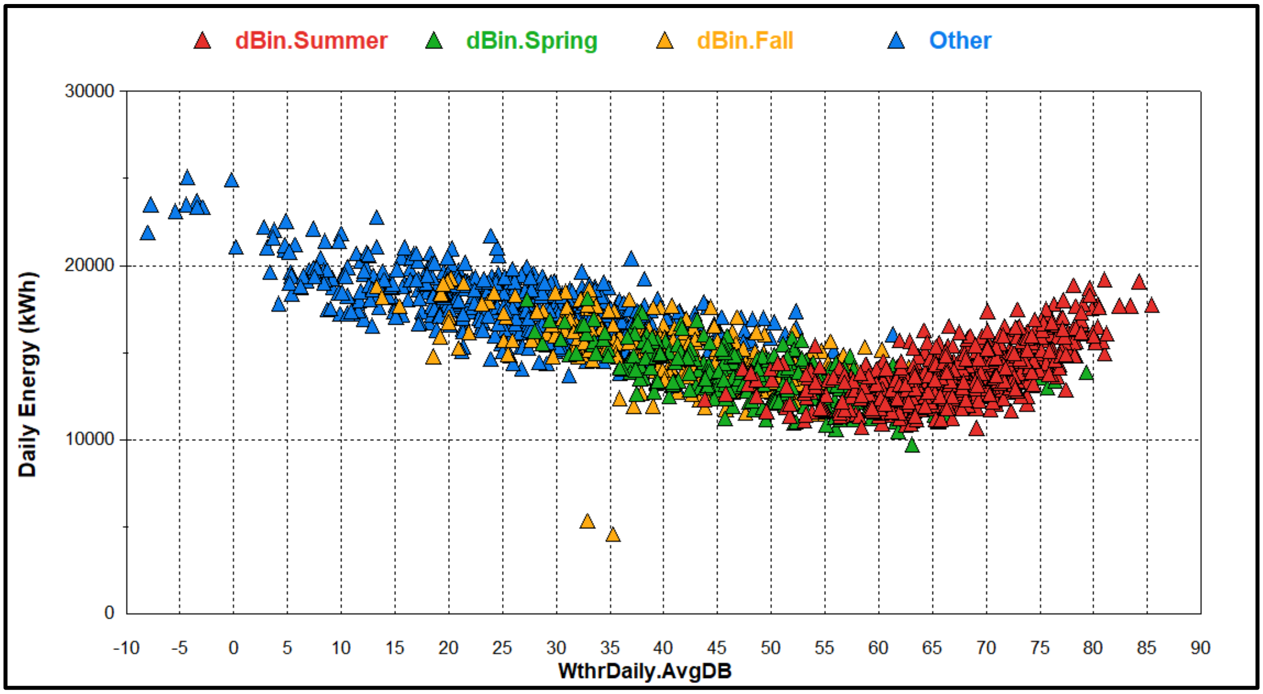
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight of VPPSA members that are clustered in north-central Vermont and Rutland weather data for the three large municipals in the central and southern regions of the state. The temperature/load relationship is evaluated at the system level. Figure 9 illustrates what this relationship looks like at the system level for Morrisville.

FIGURE 9: LOAD-TEMPERATURE RELATIONSHIP (JACKSONVILLE)



Each point represents the daily average use (in kWh) and the average temperature for that day. The curve shows us a long heating curve with heating starting at 55 degrees, and a short cooling curve with cooling starting at around 60 degrees.

Historical temperature data is used to generate daily and monthly heating-degree days (HDD) and cooling degree-days (CDD). HDD are derived using a base temperature of 55 degrees; this is the temperature point where we begin to see heating load. HDD are positive when average daily temperature falls below 55 degrees and 0 when temperatures exceed 55 degrees. CDD are defined for a 60 degree-day. CDD are positive when temperatures are above 60 degrees and 0 when average daily temperature falls below 60 degrees.

Normal or expected degree-days are used to drive the forecast. The general approach is to calculate normal degree-days as an average of past temperature or degree-days over a historical time; most utilities will use a 30-year or 20-year period. The implied assumption is that future temperatures is best represented by the average of the past. Given climate change, however, this is probably not the best assumption. Our analysis and that of others shows that average temperatures are increasing. An analysis of last 50 years of weather data for the Burlington airport shows average temperatures are increasing roughly .08 degrees per year or 0.8 degrees per decade. This is consistent with temperature trends we found in New York. Temperature trend studies have shown average temperatures increasing from 0.4 degrees to over 1.0 degrees per decade depending on geographic location. Temperature trends tend to be the lowest in cities near the ocean.

Increasing temperatures result in fewer HDD and increasing number of CDD. This is illustrated in Figure 10 and Figure 11 that show 20-year degree-day moving average against actual degree days.

FIGURE 10: HEATING TREND

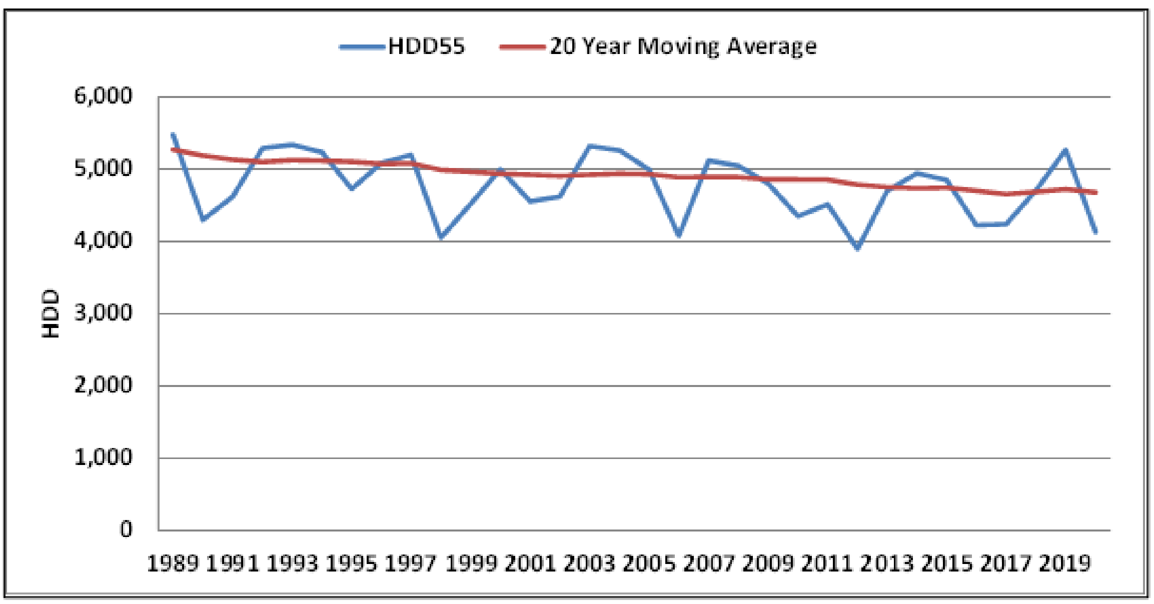
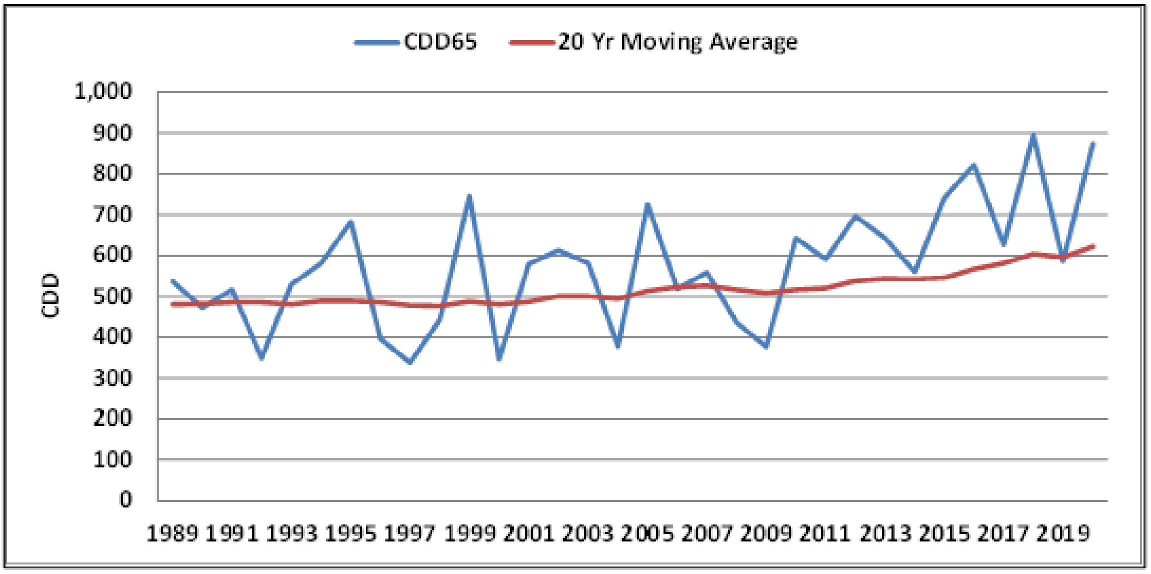


FIGURE 11: COOLING TREND



Recent climate studies show that we can expected temperatures to continue to increase. We assume HDD and CDD trends to persist through the forecast period.

Figure 12 and Figure 13 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 12: NORMAL AND TRENDED NORMAL HDD

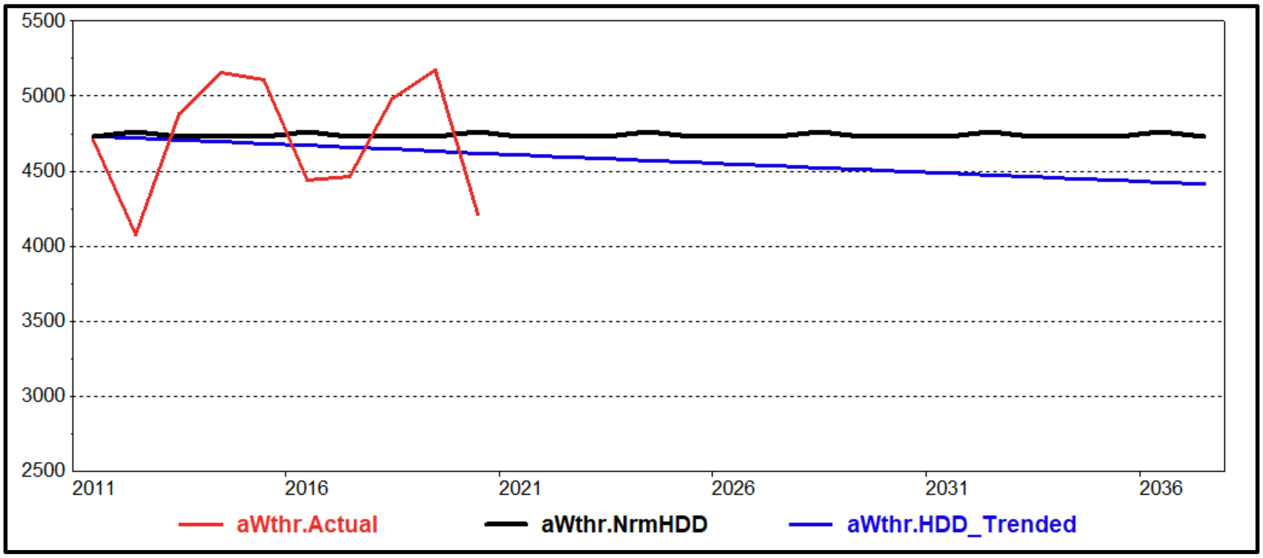
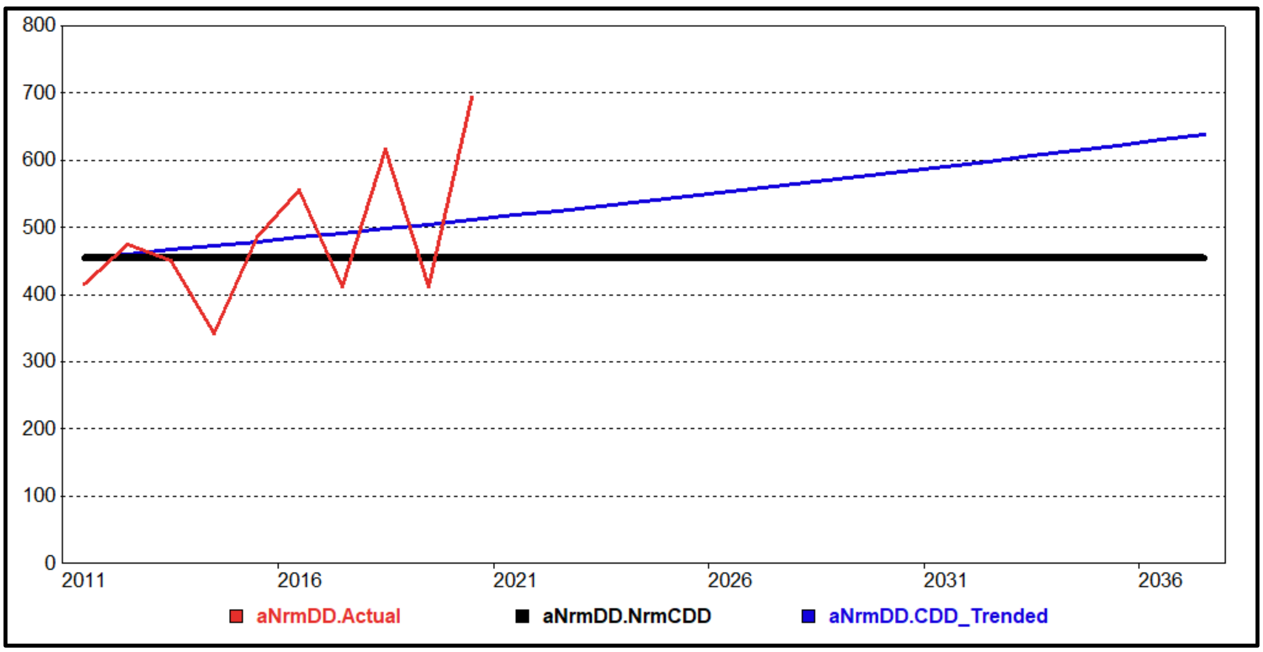


FIGURE 13: NORMAL AND TRENDED NORMAL CDD



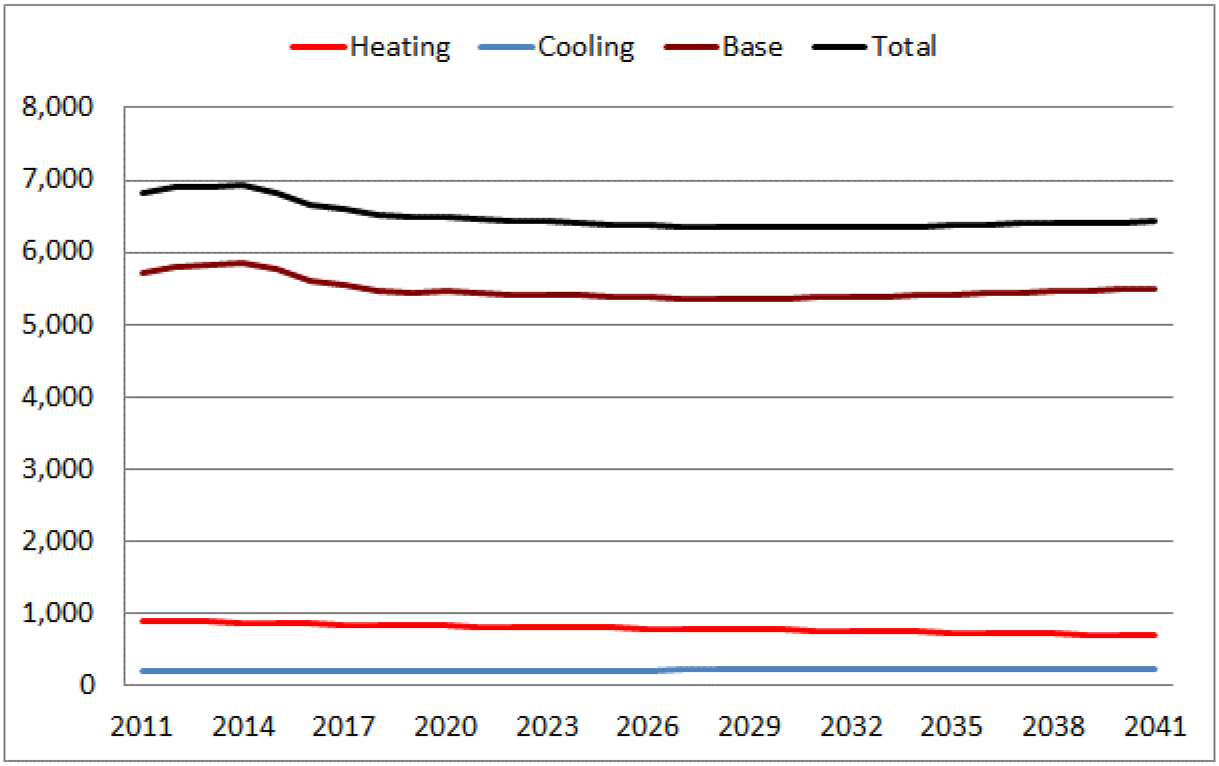
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

End-Use Intensities

Overall, sales have been flat to declining across the state. The decline is largely attributable to behind-the-meter solar adoption and end-use and efficiency gains resulting from new standards and state-incentivized energy efficiency programs. The impact of efficiency improvements is captured in the end-use intensities that reflect both changes in end-use ownership (saturation) and end-use efficiency. End-use intensities are derived for ten residential and nine C&I end-uses by combining saturation and efficiency projections. In the residential sector, intensities are measured on a kWh per household basis and in the commercial sector on a kWh per square-foot basis. End-use intensities are based on EIA 2020 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available.

For most end-uses, increasing efficiency outweighs increase in saturation contributing to declining customer average use. The exception is miscellaneous use (e.g., plug loads, appliances, electric equipment) and residential cooling; in residential cooling saturation continues to trend positive at a rate faster than improvements in air conditioning stock efficiency. Increasing CDD and incentivized heat-pumps are also expected to contribute to additional cooling-related sales. Still, aggregate cooling consumption is relatively small given temperate summer weather conditions. Figure 14 shows residential end-use intensities aggregated into heating, cooling, base, and total intensity.

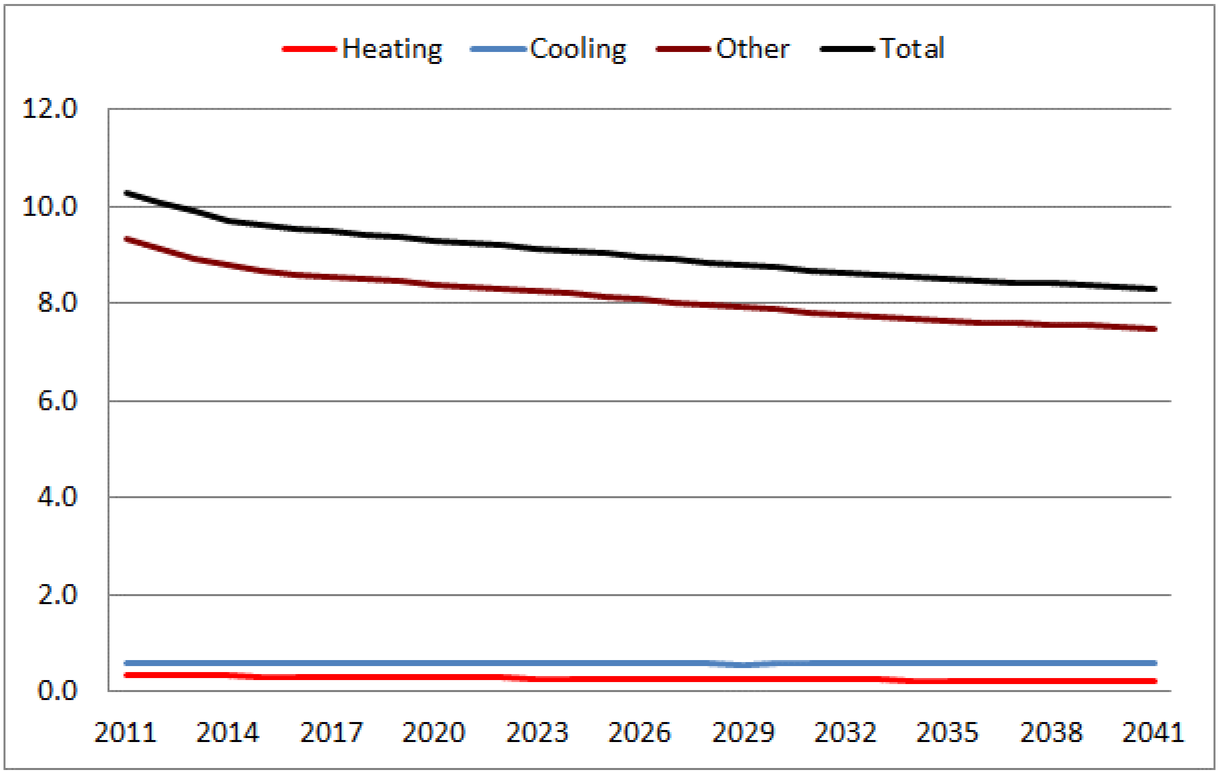
FIGURE 14: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has declined 0.7% annually with the conversion from incandescent and florescent to LED being a major contributor. The energy intensity still declines but at a much slower rate over the next ten years (-0.2% per year) as the lighting savings have been realized and the impact of new appliance standards begins to slow.

Commercial energy intensities are measured on a kWh per Sq. ft. basis. Figure 15 shows commercial heating, cooling, and other use intensity trends. Heating and cooling are a relatively small part of commercial energy use. The non-weather sensitive use (Other) is composed of seven end-uses where the largest end-uses include ventilation, lighting, refrigeration, and miscellaneous use.

FIGURE 15: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

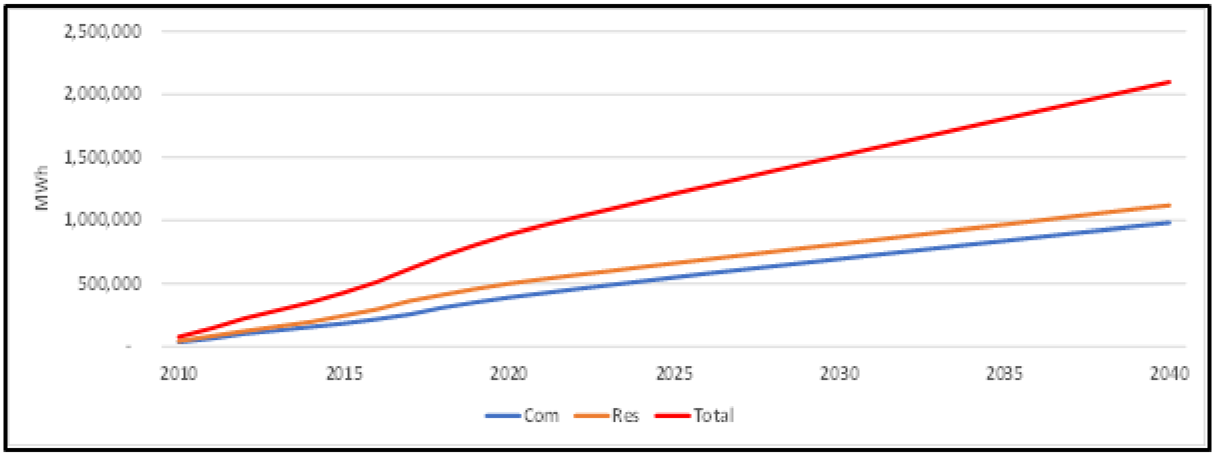


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial intensity has averaged 1.2% decline over the last ten years and is projected to decline another 0.7% over the next ten years.

EE Program Impacts

State efficiency programs have also had a significant impact on sales. At the state level, most of the impact is captured in the end-use intensities. EIA adjust end-use efficiencies to reflect New England EE program savings. Forecasts are further adjusted for Vermont-specific savings by incorporating VEIC measured and projected savings as an additional model variable. Where the variable is statistically insignificant, sales are adjusted based on allocated state EE savings projections. State savings projections are allocated to utilities based on customer class sales. Figure 16 shows the current state Demand Resource Plan (DRP) cumulative historical and projected savings.

FIGURE 16: VEIC HISTORICAL AND PROJECTED EE PROGRAM SAVINGS



Economic Outlook

The 2022 forecast is based on Moody's January 2022 state economic projections. The primary economic drivers include number of state households, population, real personal income, employment, and real economic output (GDP). Table 7 shows historical and projected economic outlook.

TABLE 7: ECONOMIC FORECAST

Year	Households (Thou)	Chg	RPI (Mil $)	Chg	GDP (Mil $)	Chg	Emp (Thou)	Chg
2011	258.9		28,119		28,981		300.9	
2012	260.2	0.5%	28,505	1.4%	29,281	1.0%	304.5	1.2%
2013	262.1	0.7%	28,624	0.4%	28,671	-2.1%	306.7	0.7%
2014	263.4	0.5%	29,295	2.3%	28,868	0.7%	309.6	0.9%
2015	264.1	0.3%	30,121	2.8%	29,163	1.0%	312.1	0.8%
2016	264.2	0.1%	30,316	0.6%	29,368	0.7%	313.3	0.4%
2017	264.5	0.1%	30,530	0.7%	29,506	0.5%	315.0	0.5%
2018	264.7	0.1%	30,895	1.2%	29,629	0.4%	316.1	0.3%
2019	265.0	0.1%	31,477	1.9%	29,775	0.5%	315.3	-0.3%
2020	263.9	-0.4%	33,348	5.9%	28,807	-3.2%	289.1	-8.3%
2021	265.1	0.5%	32,911	-1.3%	29,819	3.5%	293.5	1.5%
2022	266.6	0.6%	31,845	-3.2%	30,849	3.5%	301.9	2.9%
2023	268.3	0.6%	32,674	2.6%	31,788	3.0%	306.8	1.6%
2024	269.5	0.4%	33,550	2.7%	32,650	2.7%	309.1	0.7%
2025	270.3	0.3%	34,325	2.3%	33,439	2.4%	310.0	0.3%
2026	271.1	0.3%	35,042	2.1%	34,151	2.1%	310.2	0.1%
2027	271.7	0.2%	35,772	2.1%	34,760	1.8%	310.5	0.1%
2028	272.2	0.2%	36,583	2.3%	35,369	1.8%	310.9	0.1%
2029	272.7	0.2%	37,422	2.3%	35,986	1.7%	311.4	0.2%
2030	273.2	0.2%	38,226	2.1%	36,577	1.6%	311.8	0.1%
2031	273.5	0.1%	38,971	2.0%	37,168	1.6%	311.9	0.0%
2032	273.7	0.1%	39,711	1.9%	37,791	1.7%	311.9	0.0%
2033	273.9	0.0%	40,446	1.9%	38,443	1.7%	312.0	0.0%
2034	273.8	0.0%	41,147	1.7%	39,100	1.7%	312.1	0.0%
2035	273.7	0.0%	41,830	1.7%	39,757	1.7%	312.1	0.0%
2036	273.6	0.0%	42,494	1.6%	40,405	1.6%	311.9	-0.1%
2037	273.4	-0.1%	43,150	1.5%	41,042	1.6%	311.7	-0.1%
2038	273.0	-0.1%	43,783	1.5%	41,671	1.5%	311.5	-0.1%
2039	272.6	-0.2%	44,387	1.4%	42,302	1.5%	311.3	-0.1%
2040	272.2	-0.2%	44,973	1.3%	42,933	1.5%	311.1	-0.1%
2041	271.6	-0.2%	45,540	1.3%	43,570	1.5%	311.0	0.0%
2042	271.0	-0.2%	46,117	1.3%	44,215	1.5%	310.9	0.0%
11-21		0.2%		1.6%		0.3%		-0.2%
22-32		0.3%		2.2%		2.1%		0.3%
32-42		-0.1%		1.5%		1.6%		0.0%

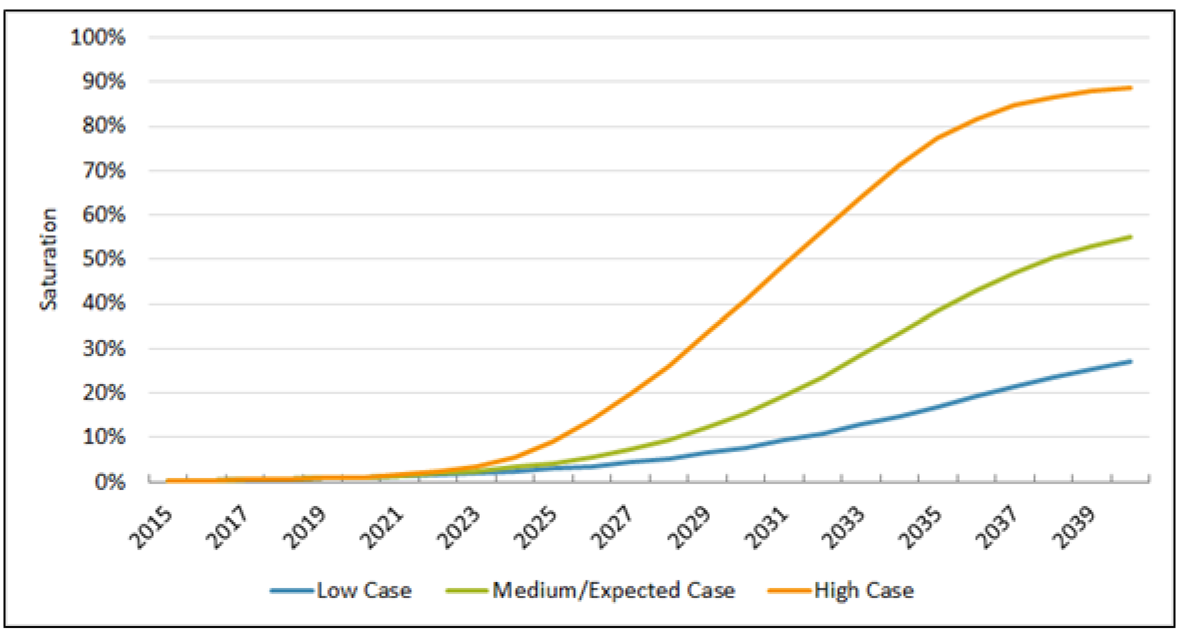
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022 with strong economic growth coming out of the COVID-driven recession.

Over the long-term, number of households is expected to average 0.3% with employment increasing at roughly the same rate. GDP averages 2.1% per year largely driven by improvements in productivity and a jump in GDP coming out of the pandemic.

Electric Vehicles

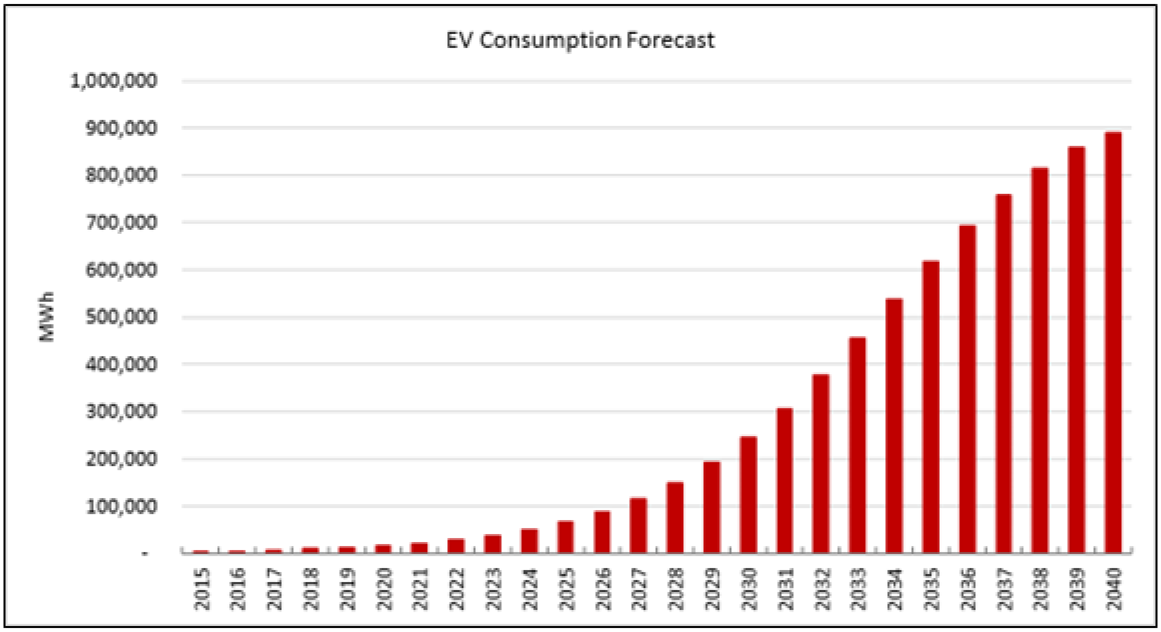
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over 15% of all vehicles are electric by 2030 and by 2050, 60% of vehicles are electric. In the high case, 90% of all vehicles are electric by 2050 with a 50% market share by 2030. In the low case 35% of all vehicles are electric by 2050. Figure 17 shows the projected adoption paths.

FIGURE 17: ELECTRIC VEHICLE SATURATION PROJECTIONS



EV saturations are translated into number of vehicles and then total charging energy requirements based on estimated annual miles driven and kWh per mile driven. Figure 18 shows state EV electric consumption for the expected case.

FIGURE 18: EXPECTED CASE STATE EV ELECTRICITY FORECAST

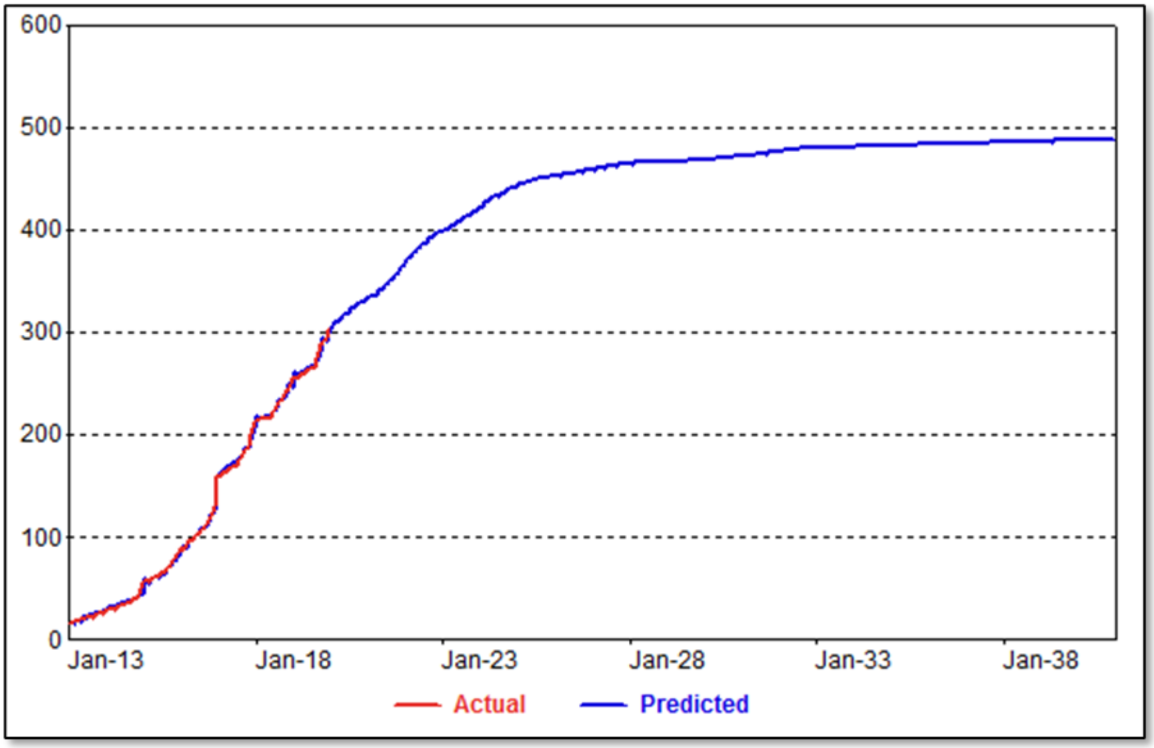


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

Solar

The solar forecast is based on Itron's behind-the-meter (BTM) solar forecast developed also as part of the 2021 VELCO long-term forecast. BTM solar capacity is derived from an investment return-based model that relates installed capacity to average system payback (number of years before investment costs are recovered). Figure 19 shows state capacity forecast.

FIGURE 19: STATE SOLAR CAPACITY FORECAST (MW)

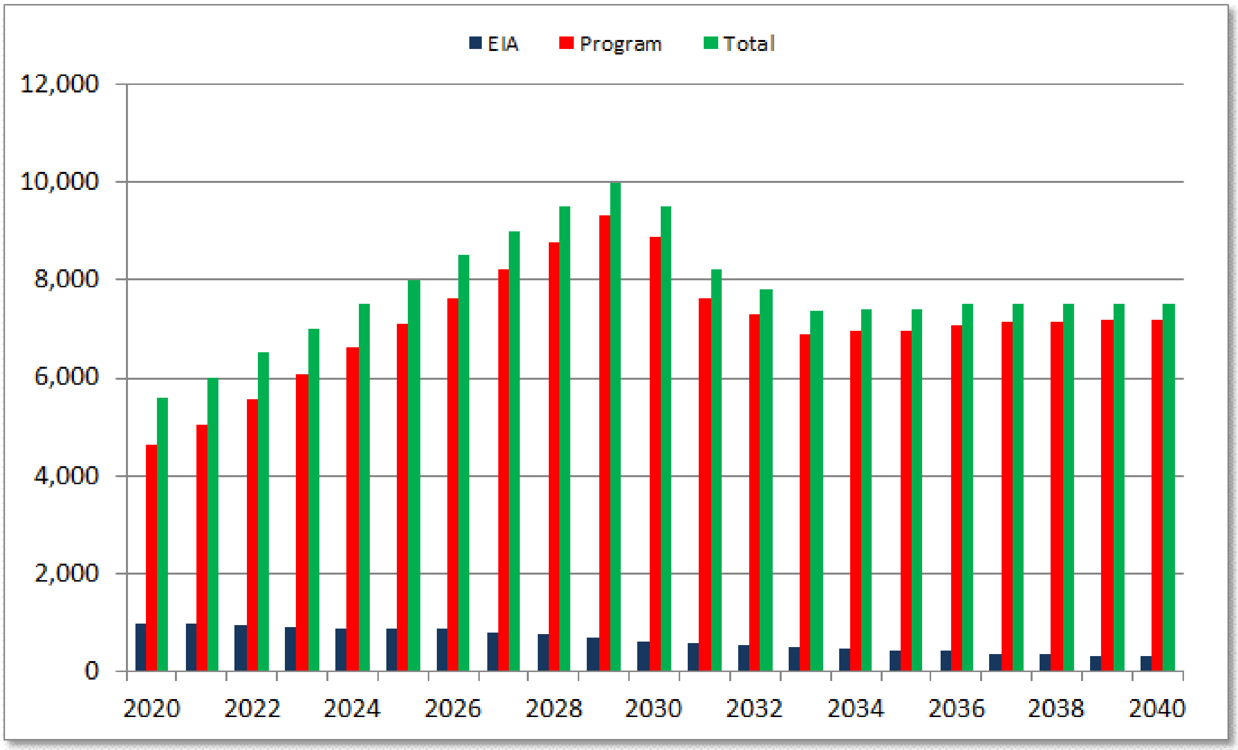


We expect the growth of BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation profile data. Our default assumption is VPPSA member BTM solar is proportional to total state generation based on number of member customers.

Cold Climate Heat Pumps

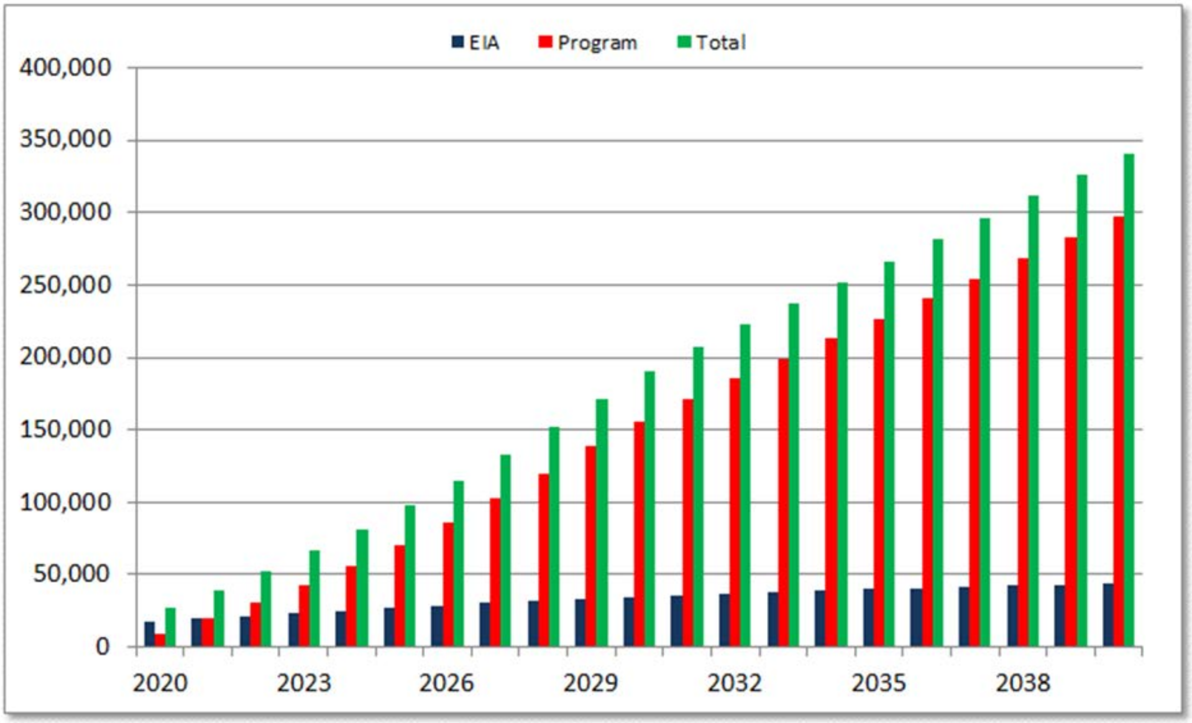
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary targets are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term forecast of CCHP units for low, medium, and high case. The reference case is based on the medium CCHP forecast with sales of around 6,000 units in the near-term, rising to 10,000 units by 2030. EIA projections are considerably more conservative with heat pumps primarily displacing electric resistant heat. Figure 20 shows state CCHP unit projections.

FIGURE 20: STATE CCHP FORECAST (UNITS PER YEAR)



VEIC further translated unit projections into electricity use based on recent CCHP measurement studies. Figure 21 shows projected state-level CCHP energy forecast.

FIGURE 21: STATE CCHP ENERGY PROJECTIONS (MWH)



CCHP sales are allocated to VPPSA members based the number of customers relative to state-level customer counts.

Itron

APPENDIX A

MODEL RESULTS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.82	0.05	16.527	0.00%
mStructRes.LagXHeat	0.432	0.05	8.677	0.00%
mStructRes.XCool	1.02	0.126	8.082	0.00%
mStructRes.LagXCool	1.367	0.126	10.82	0.00%
mStructRes.XOther	0.372	0.08	4.625	0.00%
mStructRes.LagXOther	0.46	0.082	5.622	0.00%
mCovid.ResIndex	31.43	4.807	6.538	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	131
Deg. of Freedom for Error	124
R-Squared	0.907
Adjusted R-Squared	0.903
AIC	6.088
BIC	6.242
Log-Likelihood	-577.66
Model Sum of Squares	506,780.01
Sum of Squared Errors	51,872.27
Mean Squared Error	418.32
Std. Error of Regression	20.45
Mean Abs. Dev. (MAD)	15.45
Mean Abs. % Err. (MAPE)	2.90%
Durbin-Watson Statistic	1.926

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	15.399	6.931	2.222	2.80%
AR(1)	0.997	0.008	127.822	0.00%
MA(1)	-0.742	0.061	-12.197	0.00%

Model Statistics	
Iterations	26
Adjusted Observations	131
Deg. of Freedom for Error	128
R-Squared	0.929
Adjusted R-Squared	0.927
AIC	6.681
BIC	6.746
Log-Likelihood	-620.45
Model Sum of Squares	1,295,232.93
Sum of Squared Errors	99,699.46
Mean Squared Error	778.9
Std. Error of Regression	27.91
Mean Abs. Dev. (MAD)	14.55
Mean Abs. % Err. (MAPE)	0.43%
Durbin-Watson Statistic	2.373

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	486354.048	139491	3.487	0.07%
mStructCom.LagXHeat	1099508.973	136655.6	8.046	0.00%
mStructCom.XCool	207988.909	45815.53	4.54	0.00%
mStructCom.LagXCool	404748.305	46404.19	8.722	0.00%
mStructCom.XOther	11420.177	3683.385	3.1	0.24%
mStructCom.LagXOther	31553.454	3711.778	8.501	0.00%
MA(1)	0.253	0.088	2.868	0.49%

Model Statistics	
Iterations	9
Adjusted Observations	131
Deg. of Freedom for Error	124
R-Squared	0.692
Adjusted R-Squared	0.677
AIC	19.846
BIC	20
Log-Likelihood	-1,478.82
Model Sum of Squares	110,107,765,530.01
Sum of Squared Errors	48,985,057,580.51
Mean Squared Error	395,040,786.94
Std. Error of Regression	19,875.63
Mean Abs. Dev. (MAD)	15,490.42
Mean Abs. % Err. (MAPE)	3.50%
Durbin-Watson Statistic	1.819

Large Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	804282.361	328131.6	2.451	1.56%
mStructCom.LagXHeat	551842.231	322637	1.71	8.97%
mStructCom.XCool	375222.338	108692.1	3.452	0.08%
mStructCom.LagXCool	826916.982	109689	7.539	0.00%
mStructCom.XOther	23766.151	8564.623	2.775	0.64%
mStructCom.LagXOther	71704.602	8618.652	8.32	0.00%
mBin.Aft18	123870.976	10516.75	11.778	0.00%
MA(1)	0.273	0.09	3.047	0.28%

Model Statistics	
Iterations	13
Adjusted Observations	131
Deg. of Freedom for Error	123
R-Squared	0.705
Adjusted R-Squared	0.688
AIC	21.559
BIC	21.735
Log-Likelihood	-1,590.01
Model Sum of Squares	638,129,479,164.14
Sum of Squared Errors	267,455,949,739.71
Mean Squared Error	2,174,438,615.77
Std. Error of Regression	46,630.88
Mean Abs. Dev. (MAD)	35,348.66
Mean Abs. % Err. (MAPE)	3.67%
Durbin-Watson Statistic	1.775

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.FebJun14	-103345.803	13557.57	-7.623	0.00%
mBin.Aft17	-73860.063	5656.243	-13.058	0.00%
mBin.Jan	575716.564	8866.475	64.932	0.00%
mBin.Feb	563093.22	9010.825	62.491	0.00%
mBin.Mar	553457.536	9010.63	61.423	0.00%
mBin.Apr	574057.305	9040.526	63.498	0.00%
mBin.May	570726.712	9012.655	63.325	0.00%
mBin.Jun	627474.24	9009.001	69.65	0.00%
mBin.Jul	677641.276	8865.213	76.438	0.00%
mBin.Aug	696035.899	8867.844	78.49	0.00%
mBin.Sep	683923.715	8867.86	77.124	0.00%
mBin.Oct	594773.711	8873.144	67.031	0.00%
mBin.Nov	576748.898	8866.507	65.048	0.00%
mBin.Dec	563079.092	8867.873	63.497	0.00%
mCovid.NResIndex	-38069.078	6868.725	-5.542	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	117
R-Squared	0.875
Adjusted R-Squared	0.86
AIC	20.615
BIC	20.942
Log-Likelihood	-1,532.87
Model Sum of Squares	661,949,306,225.27
Sum of Squared Errors	94,340,563,221.70
Mean Squared Error	806,329,600.19
Std. Error of Regression	28,395.94
Mean Abs. Dev. (MAD)	22,049.59
Mean Abs. % Err. (MAPE)	3.97%
Durbin-Watson Statistic	1.969

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.137	0.14	8.145	0
Seasonal	-0.255	0.737	-0.345	0.731

Model Statistics	
Iterations	26
Adjusted Observations	60
Deg. of Freedom for Error	58
R-Squared	0.999
Adjusted R-Squared	0.999
AIC	6.782
BIC	6.851
Log-Likelihood	-286.59
Model Sum of Squares	68,030,735
Sum of Squared Errors	49,480
Mean Squared Error	853.1
Std. Error of Regression	29.21
Mean Abs. Dev. (MAD)	19.9
Mean Abs. % Err. (MAPE)	0.32%
Durbin-Watson Statistic	2.008

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthr.HeatVar55	5.164	2.309	2.237	2.72%
mWthr.CoolVar60	59.357	4.487	13.228	0.00%
mCPkEndUses.BaseVar	1.803	0.022	81.394	0.00%
mBin.Aft17	-290.369	50.575	-5.741	0.00%
mBin.Mar	488.08	96.881	5.038	0.00%
mBin.May	-860.128	103.271	-8.329	0.00%
mBin.Jun	-461.844	100.255	-4.607	0.00%
mBin.Sep	-452.308	100.004	-4.523	0.00%
mBin.Oct	-561.73	109.378	-5.136	0.00%
mBin.Nov	-206.899	98.962	-2.091	3.87%

Model Statistics	
Iterations	1
Adjusted Observations	128
Deg. of Freedom for Error	118
R-Squared	0.817
Adjusted R-Squared	0.803
AIC	11.355
BIC	11.578
Log-Likelihood	-898.35
Model Sum of Squares	41,830,075.08
Sum of Squared Errors	9,349,227.03
Mean Squared Error	79,230.74
Std. Error of Regression	281.48
Mean Abs. Dev. (MAD)	215.93
Mean Abs. % Err. (MAPE)	2.81%
Durbin-Watson Statistic	1.682

APPENDIX G: 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 MW&L's Tier III programs are from four measures, we summarize the life cycle costs for electric vehicles and heat pumps in Table 1. 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 MW&L'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, and provide net benefits to both the customer and to society. They are break-even to the utility, however. 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. MW&L will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.

Morrisville Water & Light Department

2023 IRP Projected Capital Expenditures - Reference Case

Specific Projects		1 2023	2 2024	3 2025	4 2026	5 2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Hydro Investment																					
Hydro & Micro Turbines	Prod	120,954	362,863	2,783,130	2,783,130	2,783,130	2,783,130	2,783,130	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	100,000	100,000
Cady's vertical turbine	Prod	750,000	250,000																		
Flood Restoration		500,000																			
Hydro Transformer	Prod		90,000																		
Transmission Investment																					
Other 1	Trans	10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
Other 2	Trans	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Study - deficiency items																					
station.structures(switches,regulators…)	Dist	131,000	45,000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclosers		175,000				70,000	70,000	125,000		1,250,000											
poles	Dist	100,000	125,000	150,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Lines																					
Blank	Dist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rebuild Substation	Dist				225,000																
Distribution Reference case																					
AMI	Dist		500,000																		
Battery Deployment	Dist			-	-	-	-	-	-												
EV Charging	Dist			100,000	200,000	200,000	250,000	200000	50000												
SCADA & Controls	Dist				200,000	300,000	250,000	150000	100000												
LMI Service	Dist					250,000															
Peak Shaving/DERMS	Dist						100,000	400000	100000												
Transformers, services & meters	Dist			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Reference Case																					
Financial System	Gen'l		250,000																		
CIS/Billing	Gen'l																				
Cyber Security	Gen'l		100,000																		
Data System	General				250,000	250,000															
Dump Truck/Chipper	Gen'l			300,000																	
Pickup Truck	Gen'l		70,000			75,382			81,179			87,420			94,142			101,381			109,176
Bucket Truck	Gen'l	-	250,000				400,000					452,563					512,034				
Flatbed Trailer	Gen'l			25,000																	
office equip/computing/minor software	Gen'l	10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
HIGH LOAD CASE																					
High Electrification																					
Distribution Investment (on/off)	0 Dist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other																					
Other																					
Subtotal Specific Projects		$ 1,796,954	$ 2,063,363	$ 3,379,143	$ 3,854,668	$ 4,125,589	$ 4,050,758	$ 3,856,324	$ 1,072,120	$ 1,991,536	$ 742,145	$ 1,282,754	$ 743,410	$ 744,066	$ 838,881	$ 745,428	$ 1,258,168	$ 848,239	$ 747,601	$ 306,193	$ 416,149
Routine/Recurring/Misc plant & general	75% Dist / 25% Gen	75,000	76,875	78,797	80,767	82,786	84,856	86,977	89,151	91,380	93,665	96,006	98,406	100,867	103,388	105,973	108,622	111,338	114,121	116,974	119,899
Total Construction		$ 1,871,954	$ 2,140,238	$ 3,457,939	$ 3,935,435	$ 4,208,375	$ 4,135,614	$ 3,943,301	$ 1,161,272	$ 2,082,916	$ 835,810	$ 1,378,760	$ 841,816	$ 844,933	$ 942,269	$ 851,401	$ 1,366,790	$ 959,577	$ 861,722	$ 423,168	$ 536,048

Functional Summary:		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Prod		1,370,954	702,863	2,783,130	2,783,130	2,783,130	2,783,130	2,783,130	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	100,000	100,000
General	25%	28,750	699,469	355,205	280,961	357,117	432,528	33,341	115,353	35,029	35,905	576,786	37,722	38,666	133,774	40,623	553,672	144,060	43,747	44,840	155,137
Distribution	75%	462,250	727,656	309,098	860,575	1,057,089	908,642	1,115,233	491,864	1,493,535	245,249	247,005	248,805	250,650	252,541	254,480	256,467	258,503	260,591	262,731	264,924
Transmission		10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
Total Construction		$ 1,871,954	$ 2,140,238	$ 3,457,939	$ 3,935,435	$ 4,208,375	$ 4,135,614	$ 3,943,301	$ 1,161,272	$ 2,082,916	$ 835,810	$ 1,378,760	$ 841,816	$ 844,933	$ 942,269	$ 851,401	$ 1,366,790	$ 959,577	$ 861,722	$ 423,168	$ 536,048

Morrisville Water & Light Department

2023 IRP Projected Capital Expenditures - Full Electrification Case

Specific Projects		1 2023	2 2024	3 2025	4 2026	5 2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Hydro Investment																					
Hydro & Micro Turbines	Prod	120,954	362,863	2,783,130	2,783,130	2,783,130	2,783,130	2,783,130	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	100,000	100,000
Cady's vertical turbine	Prod	750,000	250,000																		
Flood Restoration		500,000																			
Hydro Transformer	Prod		90,000																		
Transmission Investment																					
Other 1	Trans	10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
Other 2	Trans	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Study - deficiency items																					
station.structures(switches,regulators…)	Dist	131,000	45,000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclosers		175,000				70,000	70,000	125,000		1,250,000											
poles	Dist	100,000	125,000	150,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000	175,000
Lines																					
Blank	Dist	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rebuild Substation	Dist				225,000																
Distribution Reference case																					
AMI	Dist		500,000																		
Battery Deployment	Dist			-	-	-	-	-	-												
EV Charging	Dist			100,000	200,000	200,000	250,000	200000	50000												
SCADA & Controls	Dist				200,000	300,000	250,000	150000	100000												
LMI Service	Dist					250,000															
Peak Shaving/DERMS	Dist						100,000	400,000	100,000												
Transformers, services & meters	Dist			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Reference Case																					
Financial System	Gen'l		250,000																		
CIS/Billing	Gen'l																				
Cyber Security	Gen'l		100,000																		
Data System	General				250,000	250,000															
Dump Truck/Chipper	Gen'l			300,000																	
Pickup Truck	Gen'l		70,000			75,382			81,179			87,420			94,142			101,381			109,176
Bucket Truck	Gen'l	-	250,000				400,000					452,563					512,034				
Flatbed Trailer	Gen'l			25,000																	
office equip/computing/minor software	Gen'l	10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
HIGH LOAD CASE																					
High Electrification																					
Distribution Investment (on/off)	1 Dist	-	-	-	-	-	-	-	-	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	-	-	-	-	-	-	-
Other																					
Other																					
Subtotal Specific Projects		**$ 1,796,954**	**$ 2,063,363**	**$ 3,379,143**	**$ 3,854,668**	**$ 4,125,589**	**$ 4,050,758**	**$ 3,856,324**	**$ 1,072,120**	**$ 4,991,536**	**$ 3,742,145**	**$ 4,282,754**	**$ 3,743,410**	**$ 3,744,066**	**$ 838,881**	**$ 745,428**	**$ 1,258,168**	**$ 848,239**	**$ 747,601**	**$ 306,193**	**$ 416,149**
Routine/Recurring/Misc plant & general	75% Dist / 25% Gen	75,000	76,875	78,797	80,767	82,786	84,856	86,977	89,151	91,380	93,665	96,006	98,406	100,867	103,388	105,973	108,622	111,338	114,121	116,974	119,899
Total Construction		**$ 1,871,954**	**$ 2,140,238**	**$ 3,457,939**	**$ 3,935,435**	**$ 4,208,375**	**$ 4,135,614**	**$ 3,943,301**	**$ 1,161,272**	**$ 5,082,916**	**$ 3,835,810**	**$ 4,378,760**	**$ 3,841,816**	**$ 3,844,933**	**$ 942,269**	**$ 851,401**	**$ 1,366,790**	**$ 959,577**	**$ 861,722**	**$ 423,168**	**$ 536,048**

Functional Summary:		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Prod2		1,370,954	702,863	2,783,130	2,783,130	2,783,130	2,783,130	2,783,130	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	542,168	100,000	100,000
General2	25%	28,750	699,469	355,205	280,961	357,117	432,528	33,341	115,353	35,029	35,905	576,786	37,722	38,666	133,774	40,623	553,672	144,060	43,747	44,840	155,137
Distribution2	75%	462,250	727,656	309,098	860,575	1,057,089	908,642	1,115,233	491,864	4,493,535	3,245,249	3,247,005	3,248,805	3,250,650	252,541	254,480	256,467	258,503	260,591	262,731	264,924
Transmission2		10,000	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483	14,845	15,216	15,597	15,987
Total Construction		$ 1,871,954	$ 2,140,238	$ 3,457,939	$ 3,935,435	$ 4,208,375	$ 4,135,614	$ 3,943,301	$ 1,161,272	$ 5,082,916	$ 3,835,810	$ 4,378,760	$ 3,841,816	$ 3,844,933	$ 942,269	$ 851,401	$ 1,366,790	$ 959,577	$ 861,722	$ 423,168	$ 536,048

Morrisville Water & Light Department
IRP Reference Case Projected Financial Results 2023-2042

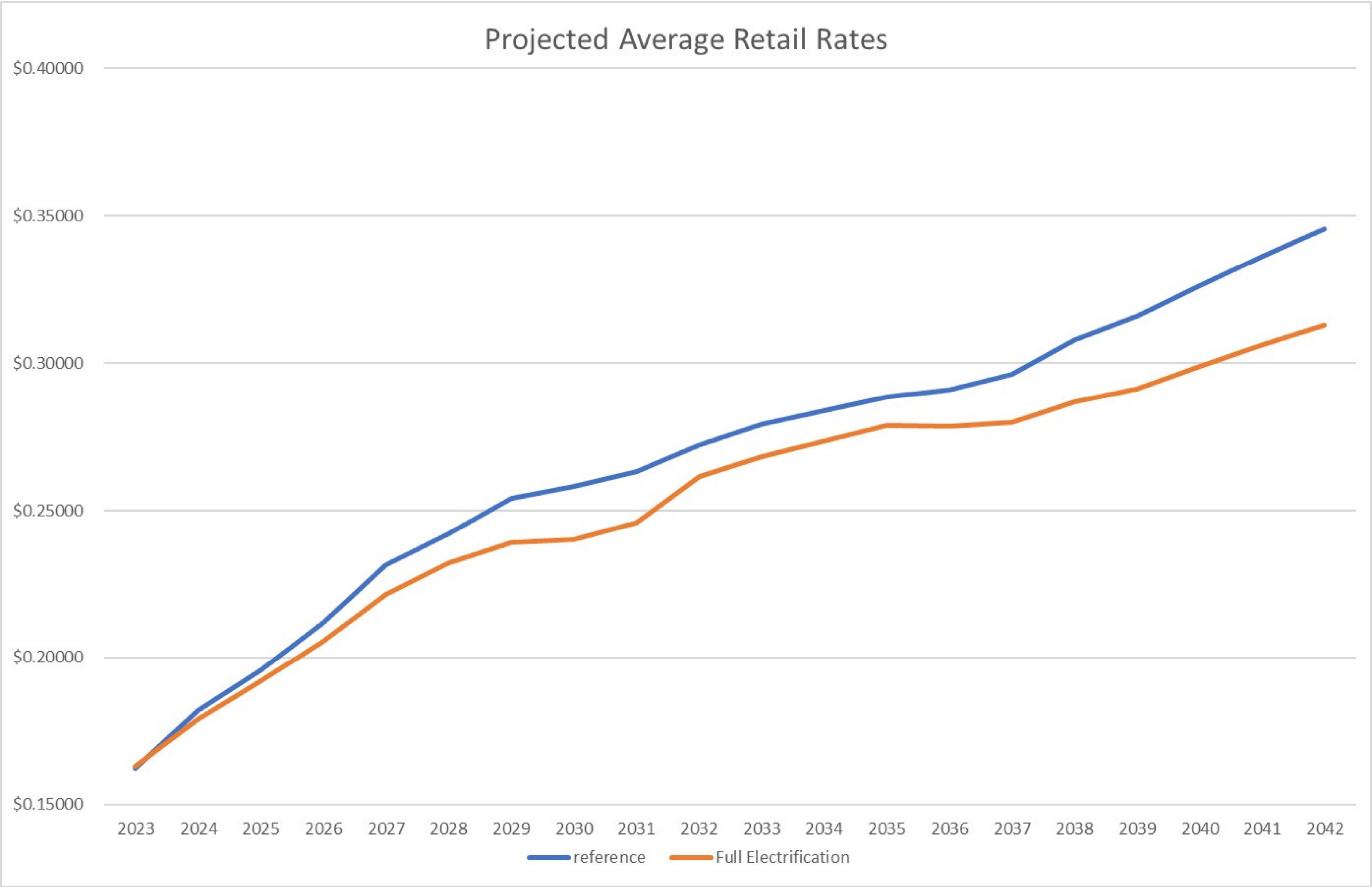
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenue Requirement Increase %	1.88%	12.13%	7.49%	8.21%	9.26%	4.67%	4.97%	1.64%	1.94%	3.33%
Retail Load MWH	46,821	46,471	46,242	46,394	46,581	47,092	47,735	48,477	49,263	50,207
Retail Load Growth		-0.7%	-0.5%	0.3%	0.4%	1.1%	1.4%	1.6%	1.6%	1.9%
Retail Revenue Requirements										
Production O&M	$ 186,538	$ 190,642	$ 194,836	$ 199,122	$ 203,503	$ 207,980	$ 212,556	$ 217,232	$ 222,011	$ 226,895
Purchased Power &TBO	4,977,309	5,548,235	5,690,329	5,953,033	6,269,744	6,616,227	6,948,872	7,267,876	7,614,957	7,692,934
TIER III projects	116,513	89,210	91,338	135,466	165,250					613,946
Other O&M	1,029,111	1,126,752	1,199,890	1,248,538	1,414,612	1,439,311	1,464,554	1,490,352	1,516,718	1,543,664
A&G	963,696	984,897	1,006,565	1,028,709	1,051,341	1,074,470	1,098,109	1,122,267	1,146,957	1,172,190
Depreciation	549,659	590,039	642,246	711,277	789,781	875,120	959,782	1,035,487	1,060,036	1,103,622
Taxes	394,155	423,327	470,456	520,208	574,859	630,485	680,703	700,970	728,109	741,948
Total Operating Expenses	$ 8,216,981	$ 8,953,102	$ 9,295,659	$ 9,796,353	$ 10,469,090	$ 10,843,594	$ 11,364,575	$ 11,834,185	$ 12,288,788	$ 13,095,200
Other Income & Expense										
Misc. Electric Revenue	126,201	128,977	131,815	134,715	137,679	140,707	143,803	146,967	150,200	153,504
Other Income	771,615	794,788	811,233	828,751	848,257	865,919	885,650	903,099	927,015	934,728
Interest Expense	140,660	214,785	347,567	494,778	646,212	782,546	898,495	869,342	880,436	827,199
Net Income	$ 140,564	$ 214,689	$ 347,471	$ 494,683	$ 646,117	$ 782,450	$ 898,400	$ 869,246	$ 880,340	$ 827,103
Total Revenue Requirement	$ 7,600,389	$ 8,458,810	$ 9,047,650	$ 9,822,348	$ 10,775,483	$ 11,401,963	$ 12,132,017	$ 12,522,707	$ 12,972,349	$ 13,661,269
Average Retail Rate $/MWH	$ 162.3	$ 182.0	$ 195.7	$ 211.7	$ 231.3	$ 242.1	$ 254.2	$ 258.3	$ 263.3	$ 272.1
YOY rate change		12.1%	7.5%	8.2%	9.3%	4.7%	5.0%	1.6%	1.9%	3.3%
Average Rates - CAGR	3.9%									
Key Cash Related Items										
Cash provided by operations	$ 554,809	$ 669,313	$ 854,302	$ 1,070,545	$ 1,300,483	$ 1,643,344	$ 1,843,956	$ 1,890,508	$ 1,932,777	$ 1,930,726
Bonds Issued	$ 1,871,954	$ 1,864,655	$ 3,199,213	$ 3,673,240	$ 3,898,788	$ 3,787,227	$ 3,434,068	$ 555,318	$ 1,412,066	$ 126,410
Construction expenditure	$ (1,871,954)	$ (2,140,238)	$ (3,457,939)	$ (3,935,435)	$ (4,208,375)	$ (4,135,614)	$ (3,943,301)	$ (1,161,272)	$ (2,082,916)	$ (835,810)
Long Term Debt Principal Payment	$ (239,405)	$ (427,443)	$ (588,639)	$ (713,566)	$ (913,297)	$ (973,264)	$ (1,141,281)	$ (1,154,761)	$ (1,184,826)	$ (1,191,147)
Operating reserve Balance	$ 551,167	$ 517,453	$ 524,389	$ 619,174	$ 696,774	$ 1,018,467	$ 1,211,909	$ 1,341,701	$ 1,418,801	$ 1,448,979
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**2.2**	**1.6**	**1.4**	**1.4**	**1.3**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
Debt % of Capital Structure	**13%**	**18%**	**26%**	**33%**	**38%**	**42%**	**45%**	**43%**	**42%**	**40%**
Reserve % of 90 day O&M Target	**30%**	**26%**	**26%**	**29%**	**31%**	**44%**	**50%**	**53%**	**54%**	**52%**

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Revenue Requirement Increase %	2.64%	1.58%	1.69%	0.79%	1.90%	3.93%	2.61%	3.28%	3.03%	2.80%
Retail Load MWH	51,113	52,124	53,192	54,295	55,126	55,855	56,465	56,994	57,262	57,549
Retail Load Growth	1.8%	2.0%	2.0%	2.1%	1.5%	1.3%	1.1%	0.9%	0.5%	0.5%
Retail Revenue Requirements										
Production O&M	$ 231,887	$ 236,988	$ 242,202	$ 247,531	$ 252,976	$ 258,542	$ 264,230	$ 270,043	$ 275,984	$ 282,055
Purchased Power &TBO	8,235,990	8,731,990	9,281,542	9,679,949	10,213,302	11,009,636	11,596,932	12,334,033	13,013,196	13,670,160
TIER III projects	662,156	696,446	737,792	799,932	836,211	872,932	915,200	948,417	977,790	1,009,088
Other O&M	1,571,203	1,599,347	1,628,111	1,657,508	1,687,551	1,718,255	1,749,635	1,781,705	1,814,480	1,847,977
A&G	1,197,978	1,224,334	1,251,269	1,278,797	1,306,930	1,335,683	1,365,068	1,395,099	1,425,791	1,457,159
Depreciation	1,120,154	1,154,946	1,171,628	1,188,386	1,208,396	1,225,316	1,259,566	1,280,070	1,297,248	1,306,545
Taxes	764,228	779,773	794,351	810,457	824,395	845,124	864,518	880,575	892,914	905,466
Total Operating Expenses	$ 13,783,596	$ 14,423,825	$ 15,106,895	$ 15,662,559	$ 16,329,761	$ 17,265,487	$ 18,015,148	$ 18,889,941	$ 19,697,404	$ 20,478,450
Other Income & Expense										
Misc. Electric Revenue	156,881	160,333	163,860	167,465	171,149	174,915	178,763	182,696	186,715	190,823
Other Income	949,405	963,197	977,066	990,769	1,004,545	1,018,583	1,032,827	1,047,680	1,062,728	1,078,520
Interest Expense	798,719	743,802	689,690	641,377	589,905	564,289	519,480	470,774	403,581	342,077
Net Income	$ 798,624	$ 743,706	$ 689,592	$ 641,279	$ 589,807	$ 564,191	$ 519,382	$ 470,676	$ 403,483	$ 341,979
Total Revenue Requirement	$ 14,274,652	$ 14,787,803	$ 15,345,251	$ 15,786,981	$ 16,333,778	$ 17,200,470	$ 17,842,419	$ 18,601,015	$ 19,255,026	$ 19,893,163
Average Retail Rate $/MWH	$ 279.3	$ 283.7	$ 288.5	$ 290.8	$ 296.3	$ 307.9	$ 316.0	$ 326.4	$ 336.3	$ 345.7
YOY rate change	2.6%	1.6%	1.7%	0.8%	1.9%	3.9%	2.6%	3.3%	3.0%	2.8%
Average Rates - CAGR										
Key Cash Related Items										
Cash provided by operations	$ 1,918,777	$ 1,898,652	$ 1,861,220	$ 1,829,665	$ 1,798,203	$ 1,789,507	$ 1,778,948	$ 1,750,746	$ 1,700,732	$ 1,648,524
Bonds Issued	$ 654,270	$ 132,113	$ 155,988	$ 286,319	$ 234,884	$ 791,593	$ 429,178	$ 369,730	$ -	$ 119,748
Construction expenditure	$ (1,378,760)	$ (841,816)	$ (844,933)	$ (942,269)	$ (851,401)	$ (1,366,790)	$ (959,577)	$ (861,722)	$ (423,168)	$ (536,048)
Long Term Debt Principal Payment	$ (1,223,860)	$ (1,230,466)	$ (1,238,265)	$ (1,252,581)	$ (1,264,326)	$ (1,303,905)	$ (1,325,364)	$ (1,343,851)	$ (1,343,851)	$ (1,349,838)
Operating reserve Balance	$ 1,419,407	$ 1,377,890	$ 1,311,899	$ 1,233,033	$ 1,150,394	$ 1,060,799	$ 983,983	$ 898,887	$ 832,601	$ 714,986
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.2**	**1.2**	**1.2**	**1.2**
Debt % of Capital Structure	**38%**	**36%**	**34%**	**32%**	**29%**	**28%**	**26%**	**24%**	**21%**	**18%**
Reserve % of 90 day O&M Target	**48%**	**44%**	**40%**	**36%**	**32%**	**28%**	**25%**	**21%**	**19%**	**16%**

Morrisville Water & Light Department
IRP Full Electrification Case Projected Revenue Requirement 2023-2042

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenue Requirement Increase %	2.40%	9.68%	7.39%	6.99%	7.78%	4.68%	3.12%	0.35%	2.37%	6.35%
Retail Load MWH	46,723	48,911	49,754	51,140	52,756	54,925	57,480	60,311	63,296	66,613
Retail Load Growth		4.7%	1.7%	2.8%	3.2%	4.1%	4.7%	4.9%	4.9%	5.2%
Retail Revenue Requirements										
Production O&M	$ 186,538	$ 190,642	$ 194,836	$ 199,122	$ 203,503	$ 207,980	$ 212,556	$ 217,232	$ 222,011	$ 226,895
Purchased Power &TBO	4,977,309	5,786,696	6,056,403	6,452,710	6,921,964	7,951,318	8,560,634	9,215,390	9,868,604	10,467,984
TIER III projects	140,628	147,595	239,128	326,191	425,732					883,785
Other O&M	1,029,111	1,126,752	1,199,890	1,248,538	1,414,612	1,439,311	1,464,554	1,490,352	1,516,718	1,543,664
A&G	963,696	984,897	1,006,565	1,028,709	1,051,341	1,074,470	1,098,109	1,122,267	1,146,957	1,172,190
Depreciation	549,659	590,039	642,246	711,277	789,781	875,120	959,782	1,035,487	1,060,036	1,168,729
Taxes	394,155	423,557	473,399	525,350	581,788	639,650	694,110	717,170	781,101	834,628
Total Operating Expenses	$ 8,241,096	$ 9,250,178	$ 9,812,466	$ 10,491,897	$ 11,388,721	$ 12,187,850	$ 12,989,745	$ 13,797,899	$ 14,595,427	$ 16,297,875
Other Income & Expense										
Misc. Electric Revenue	126,201	128,977	131,815	134,715	137,679	140,707	143,803	146,967	150,200	153,504
Other Income	772,794	797,544	813,820	831,373	851,353	869,403	890,742	909,159	933,723	941,635
Interest Expense	140,660	214,785	347,567	494,778	646,212	782,546	898,495	869,342	1,022,936	1,104,877
Net Income	$ 140,564	$ 214,689	$ 347,471	$ 494,683	$ 646,117	$ 782,450	$ 898,400	$ 869,246	$ 1,022,840	$ 1,104,781
Total Revenue Requirement	$ 7,623,325	$ 8,753,130	$ 9,561,870	$ 10,515,270	$ 11,692,018	$ 12,742,735	$ 13,752,095	$ 14,480,362	$ 15,557,279	$ 17,412,394
Average Retail Rate $/MWH	$ 163.2	$ 179.0	$ 192.2	$ 205.6	$ 221.6	$ 232.0	$ 239.2	$ 240.1	$ 245.8	$ 261.4
YOY rate change		9.7%	7.4%	7.0%	7.8%	4.7%	3.1%	0.4%	2.4%	6.4%
Average Rates - CAGR	3.3%									
Key Cash Related Items										
Cash provided by operations	$ 554,809	$ 669,313	$ 854,302	$ 1,070,545	$ 1,300,483	$ 1,643,344	$ 1,843,956	$ 1,890,508	$ 2,075,277	$ 2,273,510
Bonds Issued	$ 1,871,954	$ 1,864,655	$ 3,199,213	$ 3,673,240	$ 3,898,788	$ 3,787,227	$ 3,434,068	$ 555,318	$ 4,412,066	$ 3,130,160
Construction expenditure	$ (1,871,954)	$ (2,140,238)	$ (3,457,939)	$ (3,935,435)	$ (4,208,375)	$ (4,135,614)	$ (3,943,301)	$ (1,161,272)	$ (5,082,916)	$ (3,835,810)
Long Term Debt Principal Payment	$ (239,405)	$ (427,443)	$ (588,639)	$ (713,566)	$ (913,297)	$ (973,264)	$ (1,141,281)	$ (1,154,761)	$ (1,334,826)	$ (1,491,334)
Operating reserve Balance	$ 551,167	$ 517,453	$ 524,389	$ 619,174	$ 696,774	$ 1,018,467	$ 1,211,909	$ 1,341,701	$ 1,411,301	$ 1,487,826
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**2.2**	**1.6**	**1.4**	**1.4**	**1.3**	**1.4**	**1.4**	**1.4**	**1.3**	**1.3**
Debt % of Capital Structure	**13%**	**18%**	**26%**	**33%**	**38%**	**42%**	**45%**	**43%**	**46%**	**47%**
Reserve % of 90 day O&M Target	**30%**	**25%**	**24%**	**27%**	**28%**	**38%**	**43%**	**45%**	**44%**	**42%**

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Revenue Requirement Increase %	2.65%	1.93%	1.97%	-0.17%	0.53%	2.48%	1.46%	2.63%	2.46%	2.23%
Retail Load MWH	70,020	73,630	77,296	80,898	84,028	86,811	89,206	91,282	92,857	94,321
Retail Load Growth	5.1%	5.2%	5.0%	4.7%	3.9%	3.3%	2.8%	2.3%	1.7%	1.6%
Retail Revenue Requirements										
Production O&M	$ 231,887	$ 236,988	$ 242,202	$ 247,531	$ 252,976	$ 258,542	$ 264,230	$ 270,043	$ 275,984	$ 282,055
Purchased Power &TBO	11,136,590	12,014,995	12,980,861	13,787,099	14,723,100	15,985,376	16,939,317	18,169,087	19,286,434	20,343,598
TIER III projects	1,206,834	1,356,495	1,521,624	1,713,296	1,880,181	2,047,190	2,218,052	2,378,389	2,531,462	2,688,086
Other O&M	1,571,203	1,599,347	1,628,111	1,657,508	1,687,551	1,718,255	1,749,635	1,781,705	1,814,480	1,847,977
A&G	1,197,978	1,224,334	1,251,269	1,278,797	1,306,930	1,335,683	1,365,068	1,395,099	1,425,791	1,457,159
Depreciation	1,250,366	1,350,265	1,432,053	1,513,918	1,533,927	1,550,848	1,585,098	1,605,602	1,622,780	1,632,077
Taxes	901,985	958,569	1,014,938	1,039,670	1,058,852	1,084,080	1,108,621	1,128,857	1,146,646	1,164,181
Total Operating Expenses	$ 17,496,844	$ 18,740,994	$ 20,071,059	$ 21,237,818	$ 22,443,519	$ 23,979,972	$ 25,230,019	$ 26,728,781	$ 28,103,578	$ 29,415,132
Other Income & Expense										
Misc. Electric Revenue	156,881	160,333	163,860	167,465	171,149	174,915	178,763	182,696	186,715	190,823
Other Income	957,621	972,910	988,277	1,003,202	1,018,067	1,031,522	1,044,331	1,057,412	1,070,451	1,085,847
Interest Expense	1,202,965	1,265,601	1,320,054	1,229,047	1,133,766	1,064,871	978,078	889,018	786,283	686,231
Net Income	$ 1,202,870	$ 1,265,505	$ 1,319,956	$ 1,228,950	$ 1,133,668	$ 1,064,773	$ 977,981	$ 888,921	$ 786,186	$ 686,133
Total Revenue Requirement	$ 18,788,176	$ 20,138,857	$ 21,558,933	$ 22,525,148	$ 23,521,737	$ 24,903,179	$ 25,962,984	$ 27,266,612	$ 28,418,881	$ 29,510,827
Average Retail Rate $/MWH	$ 268.3	$ 273.5	$ 278.9	$ 278.4	$ 279.9	$ 286.9	$ 291.0	$ 298.7	$ 306.0	$ 312.9
YOY rate change	2.7%	1.9%	2.0%	-0.2%	0.5%	2.5%	1.5%	2.6%	2.5%	2.2%
Average Rates - CAGR										
Key Cash Related Items										
Cash provided by operations	$ 2,453,236	$ 2,615,771	$ 2,752,009	$ 2,742,868	$ 2,667,596	$ 2,615,620	$ 2,563,078	$ 2,494,523	$ 2,408,965	$ 2,318,210
Bonds Issued	$ 3,634,847	$ 3,079,780	$ 3,069,562	$ 168,851	$ 87,751	$ 647,855	$ 305,182	$ 273,498	$ -	$ 56,477
Construction expenditure	$ (4,378,760)	$ (3,841,816)	$ (3,844,933)	$ (942,269)	$ (851,401)	$ (1,366,790)	$ (959,577)	$ (861,722)	$ (423,168)	$ (536,048)
Long Term Debt Principal Payment	$ (1,673,077)	$ (1,827,066)	$ (1,980,544)	$ (1,988,986)	$ (1,993,374)	$ (2,025,767)	$ (2,041,026)	$ (2,054,701)	$ (2,054,701)	$ (2,057,524)
Operating reserve Balance	$ 1,524,072	$ 1,550,741	$ 1,546,836	$ 1,527,299	$ 1,437,872	$ 1,308,790	$ 1,176,447	$ 1,028,046	$ 959,143	$ 740,257
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**1.3**	**1.3**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.1**	**1.1**	**1.1**
Debt % of Capital Structure	**48%**	**48%**	**48%**	**45%**	**42%**	**40%**	**37%**	**34%**	**31%**	**28%**
Reserve % of 90 day O&M Target	**40%**	**38%**	**35%**	**33%**	**29%**	**25%**	**21%**	**17%**	**15%**	**11%**


Projected Average Retail Rates
$0.40000
$0.35000
$0.30000
$0.25000
$0.20000
$0.15000
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
reference
Full Electrification

Debt Management Policy

PURPOSE. The purpose of this Policy is to establish the guidelines for the issuance of debt by the Village of Morrisville Water & Light. Debt levels and the related annual debt service expenditures are important long-term obligations that must be managed with available short- and long-term resources. This policy also addresses the level of indebtedness that the Village can reasonably expect to incur without jeopardizing its existing financial position.

Adherence to a debt management policy, along with the utilization of other sound and prudent financial practices and the Village's other financial policies, will assure the lending market that the Village is well managed and will meet its obligations in a timely manner.

PLANNING AND PERFORMANCE. Debt management means adopting and maintaining financial plans for both the issuance and repayment of debt. The determination to issue new debt should be made as part of the adoption of the annual capital budget, which prioritizes capital projects and identifies the various funding sources available for those projects. Planning for the repayment of debt will include analysis of the operating budget to determine if the fund will incur the additional debt service required by the new debt. MWL will seek to remain within the norm for American electric utilities by having a debt-to-equity ratio that does not exceed 40 – 60% debt to equity.

USE OF SHORT-TERM AND LONG-TERM DEBT. Short-term debt should be limited to borrowing to cover short-term, temporary cash flow shortages within the Village's fiscal year through the use of tax anticipation or revenue anticipation notes in those instances where there is an inadequate level of cash flow, or through the use of bond anticipation notes when cash is required to initiate a capital project prior to the receipt of bond proceeds. Management, consistent with guidance from the trustees should manage the Village's finances so as to avoid the use of short-term debt when possible.

Long-term debt should be issued for the acquisition, construction, or improvement of land, buildings, infrastructure, and public improvements that cannot be financed from current revenues or other resources. Current year budget appropriations and accumulated reserve funds should be used, as practicable, to minimize the amount of long-term borrowing that is required to preserve available debt to equity availability for major improvements that will be necessary in the coming years.

PURPOSE OF DEBT. General obligation debt funded by general fund property taxes shall be used for projects that provide a general benefit to Village residents and that cannot otherwise be self-supporting. Debt incurred for use by an enterprise fund, even if backed by a general obligation pledge of the Village, shall be self-supporting and repaid solely from the revenues of such fund, unless a general benefit to Village residents can be demonstrated.

REPAYMENT OF DEBT. The management, consistent with guidance from the trustees will conservatively project the revenue sources that will be utilized to repay any debt and will analyze the impact on voters of both the additional debt service as well as any additional operating expenses resulting from the improvements, to determine if new debt should be issued and to structure the appropriate repayment terms for each debt issue. The maturity of long-term debt shall be kept as short as possible to minimize the overall impact on the taxpayers during the life of the debt. At the same time, it should not be so short that the repayment will create an unreasonable burden. In no event shall the life of the debt exceed the life of the improvement being financed.

The foregoing Policy is hereby adopted by the Trustees of the Village of Morrisville, Vermont, this 19th day of July, 2023 and is effective as of this date until amended or repealed.

Village Trustee Chair

Bradley G. Limoge

Robert V. Hemm

FINANCIAL & PROCUREMENT
POLICY

Purpose

The purpose of this Purchasing Policy is to obtain the highest quality goods and services for the Village of Morrisville Water & Light at the lowest possible price, to exercise financial control over the purchasing process, to clearly define authority for the purchasing function, to allow fair and equal opportunity among qualified suppliers, and to provide for increased public confidence in the procedures followed in public purchasing.

General Requirements

The Village of Morrisville Water & Light requires that procurement activities be performed in an equitable and competitive manner in an effort to promote equal treatment, efficiency, and economy in all activities.

Annually, the MWL staff shall prepare, and the Board shall review and approve, detailed operating and capital budgets for each department.

All financing will be developed and recommended by the staff and subject to review and approval by the Village Trustees and or, where required, by the Village voters.

The sale of all assets of more than $10,000 will require Village Trustee approval and the Trustees will be informed of all other sales.

The creation of any new position for permanent, full-time employment will be recommended by staff and subject to MWL Trustee review and approval.

MWL staff shall have full authority to fill vacancies in existing positions so long as said position is included in the then current year operating budget.

The MWL staff will have full authority to hire part-time and or full time temporary employees consistent with the ability to be paid for within the then current year operating and or capital budgets.

Purchasing Authority

Department Head Limits - Department Heads are authorized to make purchases in amounts up to $25,000.00 for routine purchases of materials, vendors, and or services for items included in the current year budget. Routine purchases over $25,000 as well as purchases of items not included in the current year budget of greater than $2,500 must have prior approval by the Village Manager. Department heads may authorize staff to make purchases, with their authorization, of up to $500.

Village Manager Limits -The Village Manager is authorized to make purchases for routine purchases of materials, vendors, and or services for items included in the current year budget. Purchases of items not included in the current year budget may be approved by the Village Manager so long as they determine the purchase will not impact the bottom line of the approved budget. For purchases not included in the budget and that may negatively impact the budget at years end, the Village Manager shall seek approval by the Village Trustees for purchases greater than $50,000 .

Purchase Process of Services, Supplies and Property over $20,000 (less than $100,000)

Purchases over *$20,000.00* are required to get 3 price rates or quotations. There may be times when the price rates or quotations may be waived. Instances of these are:

1. there is a lack of vendors that supply the product being purchased
2. material or services required under an emergency situation where time is of the essence
3. material or services for components critical to a system
4. when less than 3 responses have come back on a bid
5. where particular professional services are required
6. where a particular product is desired for educational or training work
7. where equipment is already installed and in service and it is determined advantageous to purchase it
8. where, at the discretion of the Board of Trustees, it is deemed appropriate to waive the competitive bid requirements or;
9. the **funding agency requires** the Village to utilize a competitive process for professional services at a dollar volume less than $20,000.00.

The solicitation of bids can be done either by an ad in the local paper, by phone call to specific vendors or by correspondence specific vendors.

Competitive Bidding Requirements for Services, Supplies or Property over $100,000 and or when Federal funding is involved.

Purchases over *$100,000* or when required by federal or state requirements are required to get 3 competitive bids. In these instances, one of the procurement methods below shall be followed:

Four Proper Procurement Methods

1. **Sealed bidding** (evaluated on price alone)
   Generally, the sealed bid is the preferred method for procuring construction, assuming:
   - an adequate specification or purchase description is available;
   - at least two qualified bidders are willing and able to compete for the contract;
   - the procurement is suitable for a fixed-price contract; and

- the contract may be awarded principally on the basis of price.

2. **Competitive proposals** (advantage to project and price)
More than one source submits a bid and the successful bidder is awarded either a fixed-price or a cost-reimbursement type contract. This method is used primarily in situations where sealed bids are inappropriate.

3. **Noncompetitive proposals** (When materials, supplies, equipment and real property are under $100,000 and Federal funding is made available a price analysis will be performed)
Involves solicitation of a proposal from only one source, conducted only when:
a) a contract cannot feasibly be awarded under simplified acquisition procedures, sealed bids, or competitive proposals; and
b) the awarding **agency authorizes** noncompetitive proposals; and
c) at least one of the following conditions applies:
    - only one source is capable of supplying the item or service;
    - emergency conditions justify bypassing competitive methods in order to minimize delay;
    - several sources were solicited, but competition was deemed inadequate.

4. Simplified acquisition procedures
Price rates or quotations are to be obtained from an adequate number of qualified sources.

5. Qualification Based Selection
When required by state or federal requirements, engineering or architectural services may be selected in a QBS process. Bidders provide qualifications, without pricing, and MWL then attempts to negotiate price with that firm. If unsuccessful, MWL then moves to the next firm.

Bid Solicitations

Bid solicitations must be designed to ensure that competition is not compromised, where applicable, and that bidders have all the information they need to submit a qualified bid. For sealed bids and competitive proposals, solicitations must be publicized.

If the Village staff can perform the same work as a contractor, then the Village, at its discretion may waive the bid process and use its own staff.

Bid Selection

The Village reserves the right at its sole discretion to reject any and all bids, wholly or in part, to waive any informalities or any irregularities therein, to accept any bid even though it may not be the lowest bid, to call for rebids, to negotiate with any bidder, and to make any award which in its sole and absolute judgment will best serve the Village's interest. The trustees reserve the right to investigate the financial responsibility of any bidder to determine his or her ability to assure service throughout the term of the contract.

Debarment and Suspension

When evaluating potential bidders, the prospective contractor's integrity, record of past performance, and financial and technical resources will be considered. In addition, the Village of Morrisville Water & Light will ensure that the potential contractor has not been debarred, suspended, or convicted of criminal violations under the Clean Air Act or other similar federal statutes, in which case the contractor must be disqualified from consideration.

Davis-Bacon Act and Contract Work Hours and Safety Standards Act

The Village of Morrisville Water & Light complies with the Davis-Bacon Act and the Contract Work Hours and Safety Standards Act, as required, when federal funds are used. These Acts ensure that all laborers and mechanics employed by contractors and subcontractors under a federally sponsored or funded project receive the prevailing wage rate based on a forty-hour work week and receive overtime at the rate of one and one-half times regular rate for all work hours in excess of forty per week. The Secretary of Labor determines the appropriate wage rate by computing the prevailing rate for a particular construction trade within a specific geographic area.

The Contract Work Hours and Safety Standards Act also sets requirements for the handling and disposing of hazardous materials to protect laborers and mechanics from unsafe exposure to such materials. Contractors must inform their employees of all hazards in which they may be exposed, relative symptoms and appropriate emergency treatment and proper conditions and precautions for safe use and exposure. Contractors must prepare and submit a Material Safety Data Sheet (MSDS) to the contracting officer for all hazardous materials prior to the award of the contract.

Small, Minority and Women's Businesses
If the contractor intends to let any subcontracts for a portion of the work, the contractor shall take affirmative steps to assure that small, minority and women's businesses are provided the opportunity to provide competitive quotes as sources of supplies, equipment, construction, and services.

Anti-Kickback
The contractor shall comply with the Copeland Anti-Kickback Act (18 USC 874) as supplemented in Department of Labor regulations (29 CFR, Part 3). This act provides that each contractor shall be prohibited from inducing, by any means, any person employed in the construction, completion, or repair of public facilities, to give up any part of the compensation to which they are otherwise entitled. The Village shall report all suspected or reported violations to the funding Agency.

Equal Opportunity Requirements
For all contracts in excess of $10,000, the contractor shall comply with Executive Order 11246, entitled "Equal Employment Opportunity," as amended by Executive Order 11375, and as supplemented in Department of Labor regulations (41 CFR Part 60).

Payment of Invoices
The Village of Morrisville Water & Light has made it a policy to pay all local (Morrisville) vendors upon receipt if at all possible. The Village does not take advantage of the 30-day remittance period but submits payment with the next regular accounts payable check run in order to keep the money circulating within the community.

Capitalization of Purchases
Purchases will be capitalized in the appropriate fund when they meet the following conditions:

1. Cost more than *$5,000.00.,* and
2. Have a life of more than five (5) years; or independent of 1 and 2
3. If it is a major repair to an existing asset, it extends the life of the asset, and the asset would be of no value without the repair.

When the cost is split between departments, the total cost will be used for determination of capitalization.

Some items that would not be capitalized even though they would be considered major purchases would be:

1. Cleaning of the water wells
2. Painting of buildings or equipment
3. Repairs of leaks in the water or sewer system, unless sections of new pipe are installed
4. Repairs to the electric system, unless new sections of lines are replaced
5. Normal maintenance to the hydro units

Adopted and dated at for The Village of Morrisville Water & Light.

The foregoing Policy is hereby adopted by the Trustees of the Village of Morrisville Water & Light, Vermont, this ____ day of July; 2023 and is effective as of this date until amended or repealed.

Village Trustee Chair