VILLAGE OF HYDE PARK ELECTRIC DEPARTMENT 2019 IRP

2019 INTEGRATED RESOURCE PLAN

JULY 31, 2019

30 V.S.A §218C

SUBMITTED BY:
Energy New England, LLC
On behalf of The Village of Hyde Park Electric Department
CONTRIBUTORS:
Michelle Coscia, and Timothy Hebert of Energy New England;
Carol Robertson, Village of Hyde Park Electric Department Manager

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A Executive Summary

A.1 Overview

The Village of Hyde Park Electric Department's (HPE or Hyde Park) 2019 Optimal Integrated Resource Plan is filed pursuant to Vermont Statute 30 V.S.A. § 202a. The New England wholesale energy market continues to evolve, bringing various challenges and opportunities to Hyde Park and its customers. By operating within a changing environment, Hyde Park faces uncertainty and volatility that the energy market creates. The intent of the plan submitted herein is for Hyde Park to continue providing reliable, reasonably priced energy services while managing risk for the utility and its customers. To better navigate this ever-changing energy market, Hyde Park consults with Energy New England, LLC (ENE), who helps it participate in the ISO New England markets and gives guidance in the structuring of short and long-term power contracts. The Village of Hyde Park Electric Department, Energy New England, LLC, and Vermont Public Power Supply Authority (VPPSA) prepare this Integrated Resource Plan.

Hyde Park uses the IRP as a key tool in developing its strategic plan. The strategic goal is to optimize Hyde Park's portfolio with a cost structure that stabilizes rates and improves the financial health, services, and environmental impact for the electric department. Hyde Park understands there will always be tradeoffs to consider when deciding on various issues concerning future projects and contracts.

This planning process considers a number of key influencers to the energy market and several strategies that Hyde Park could utilize when continuing to build its long-term resource portfolio. Such concepts include:

- Incorporate future resources that balance low present value costs while reducing the environmental footprint of the portfolio. Hyde Park aims to construct a portfolio that is both fiscally and environmentally responsible for their customers. Currently, Hyde Park's energy portfolio is 30% carbon free or carbon neutral and with the new Renewable Energy Standard (RES), Hyde Park intends to seek out future resources that serve to fill RES needs while being economical.

- Consider long-term resources that provide protection against adverse market conditions. Hyde Park will seek flexible pricing that will work to mitigate current commitment to substantially out-of-market resources.

- Hyde Park will seek out and review Vermont-based resources to help it comply with RES. In addition, behind-the-meter generation projects that will reduce emissions in Hyde Park will be priority for analysis, as they will enable Hyde Park to fill RES standards that began in 2017.

A.2 IRP Outline

Section A. Table of Content gives titles and page numbers per section of the report

Section B. Executive Summary provides an overview of the report

Section C. Forecasts and Scenarios includes load forecasts and scenarios

Section D. Assessment of Environmental Impact gives value to the significant environmental attributes of the resource portfolio.

Section E. Data Models and Information

Section F. Assessment of Resources reviews existing resources as well as supply options, models and integration of new resources in order to select the preferred portfolio.

Section G. Renewable Energy Standard Analysis

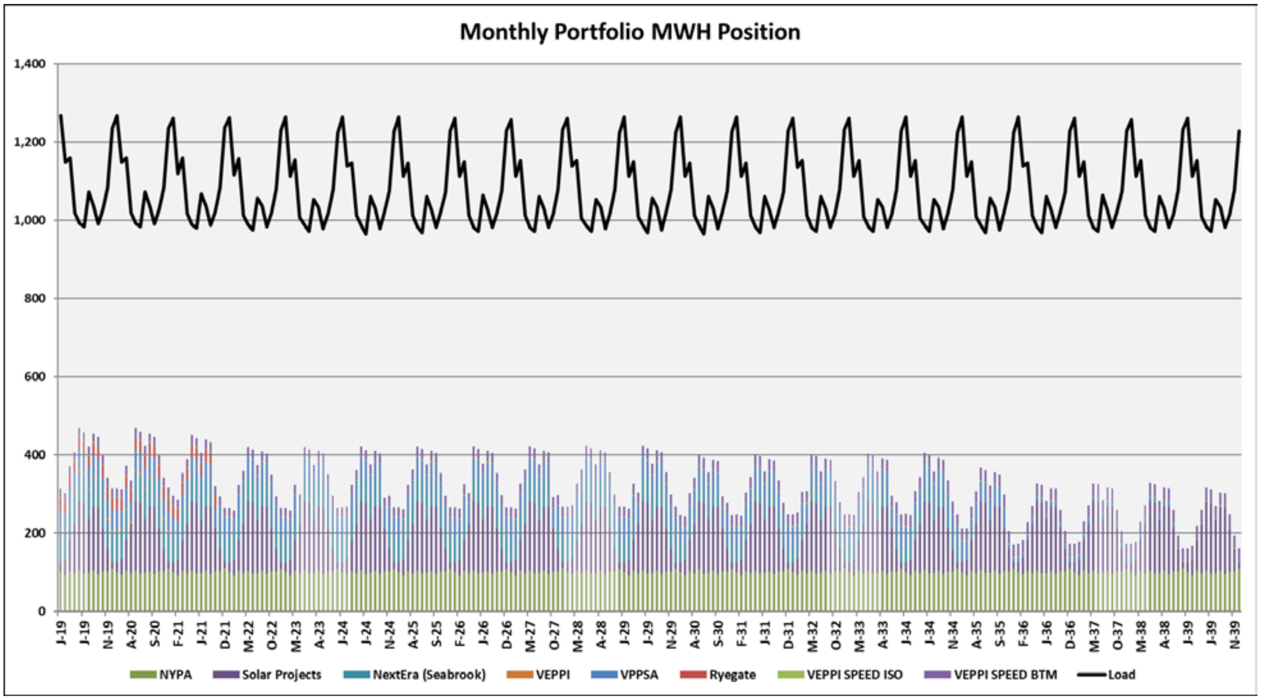
Section H. Assessment of the Transmission and Distribution System evaluates system improvement of efficiency and reliability for bulk transmission, grid modernization and vegetation management.

Section I. Integrated Analysis and Plan of Action is an assessment of demand, supply, finances, transmission, and distribution to find the least-cost portfolio and preferred plan of action.

A.2.1 Resources Requirements

Hyde Park has seen a steady increase in sales numbers, with an 3% growth of real time load from 2014 to 2018. Although Hyde Park has a solar project for the life of unit in their portfolio, they do have a supply gap to address in the future. While this IRP analyzes various portfolio options, it also addresses both coverage and Renewable Energy Standard requirements. The benefits of certain resources in the RES program will have greater implications to HPE’s overall power costs. Therefore, assessment of resources is based on not only potential cost, but RES offset as well.

Figure 1: Energy Supply Gap

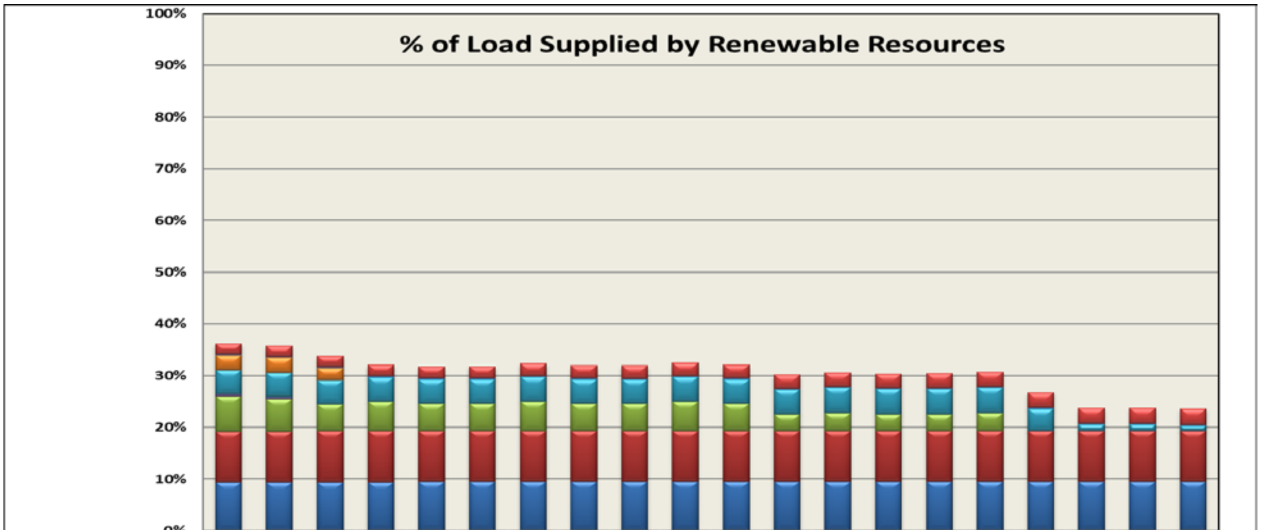


The “Base Case” load forecast (black line in Figure 1) has load maintaining steady. Hyde Park intends to continue to explore ways to supply its portfolio with renewable best benefit solutions.

A.2.2 Hyde Park’s Renewable Supply Portfolio

Currently, Hyde Park has over 30% renewable energy resources in their supply portfolio. This includes solar entitlements and Purchase Power Agreements (PPAs) that have qualified Renewable Energy Certificates (RECs) and/or State-approved RECs for RES. Figure 2 shows the base case load applied and matches it to the forecasted output of HPE’s renewable resources. While Hyde Park's current portfolio is largely renewable based, the one exception is the Seabrook offtake contract. Although Seabrook’s attributes do not count towards RES compliance, it is still a carbon-free energy source in HPE’s portfolio. When focusing on alternative resources, HPE will continue to search out renewable generation and, at the same time, keep in mind overall power costs that may affect customer rates. With RES compliance part of the power costs, renewable generation has the ability to offset RES compliance costs. Hyde Park’s RES position if not covered by owned RECs will be addressed by purchasing RECs in the market.

Figure 2: Renewable Portfolio



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
VEPPI SPEED BTM	2.1%	2.1%	2.2%	2.2%	2.3%	2.3%	2.4%	2.4%	2.5%	2.5%	2.6%	2.6%	2.7%	2.7%	2.8%	2.9%	2.9%	3.0%	3.0%	3.1%
VEPPI SPEED ISO	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Ryegate	2.9%	2.9%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro Quebec	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.9%	4.9%	4.9%	4.9%	4.2%	1.2%	1.2%	1.0%
VEPPI	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NextEra (Seabrook)	6.8%	6.3%	5.2%	5.7%	5.2%	5.2%	5.7%	5.2%	5.2%	5.7%	5.2%	3.2%	3.5%	3.2%	3.2%	3.5%	0.0%	0.0%	0.0%	0.0%
Solar Projects	9.8%	9.8%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%
NYPA	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%

A.2.3 Resource Alternatives

Hyde Park will always try to seek resources for its portfolio that lower cost and are beneficial to State or ISO cost. With Renewable Energy Standard beginning in 2017, HPE has begun to seek fair and equitable ways to promote energy efficiency as well as energy transformation.

The IRP process selected combinations of potential resources for evaluation. Together, Hyde Park and ENE chose four scenarios using an optimization algorithm, which is explained in section I.2. ENE's simulation models can be found in section Data Models and Information tested each portfolio for performance within simulated in market environments. The evaluation review chose the ideal scenario using four major criteria:

1) Least Cost: Mean of the Net Present Value (NPV) of the total portfolio; this includes energy cost of both current resources and potential scenario resources
2) Renewable Energy Standard: Mean of each scenario based on current RES coverage and resources for each scenario.

3) Standard Deviation: Risk of each scenario relative variation of the expected NPV of Total Portfolio Cost and RES, as measured by the standard deviation and various tradeoff considerations
4) Spot Market Exposure: The relative spot market exposure to Hyde Park based on each scenario.

A.2.4 Comparative Tradeoff Analysis and Risk

The Energy New England Portfolio Simulation Model used a couple of simulation-based models that estimate future values of the input variables. The simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Hyde Park's resource portfolio under different market conditions and identifies the factors to which the performance is most sensitive. Simulated data sets include VT to MA Hub basis, AGT Delivered Gas Price, Around the Clock MA Hub LMP, Around the Clock VT Hub LMP, Total Annual Cost for the portfolio, Coverage, and Unit capacity factor.

The energy NPV was a large weight within each scenario model because the cost drives the most impact to HPE. The RES section of HPE's energy portfolio has the second largest risk if left unhedged.

The I.1 Evaluation of Portfolio Scenarios section describes the details of all five scenarios. Table 1 below shows a few scenarios the IRP process analyzed.

Table 1: Comparative Portfolio

	Scenario	***NPV Total Cost***	***Total RES***	***Std Dev***	***Spot Exposure Target Deviation***
Least Cost	Scenario #1	$ 9,460,905	$721,763	$ 2,361,985	30%
High Cost	Scenario #5	$ 12,736,440	$ 28,897	$ 1,042,526	73%
Optimal Scenario	Scenario #2	$ 10,254,529	$ 603,112	$ 1,349,542	63%

Here are the highlights of the most competitive resource combination along with Hyde Park's current resource portfolio:

I. Scenario 1 (Base Case) maintains the current portfolio as status quo and does not procure new resources. This set a baseline for comparing alternatives. In the current market environment, this approach can be effective, but requires comparison to a multitude of potential future market states. This scenario is the least cost scenario.

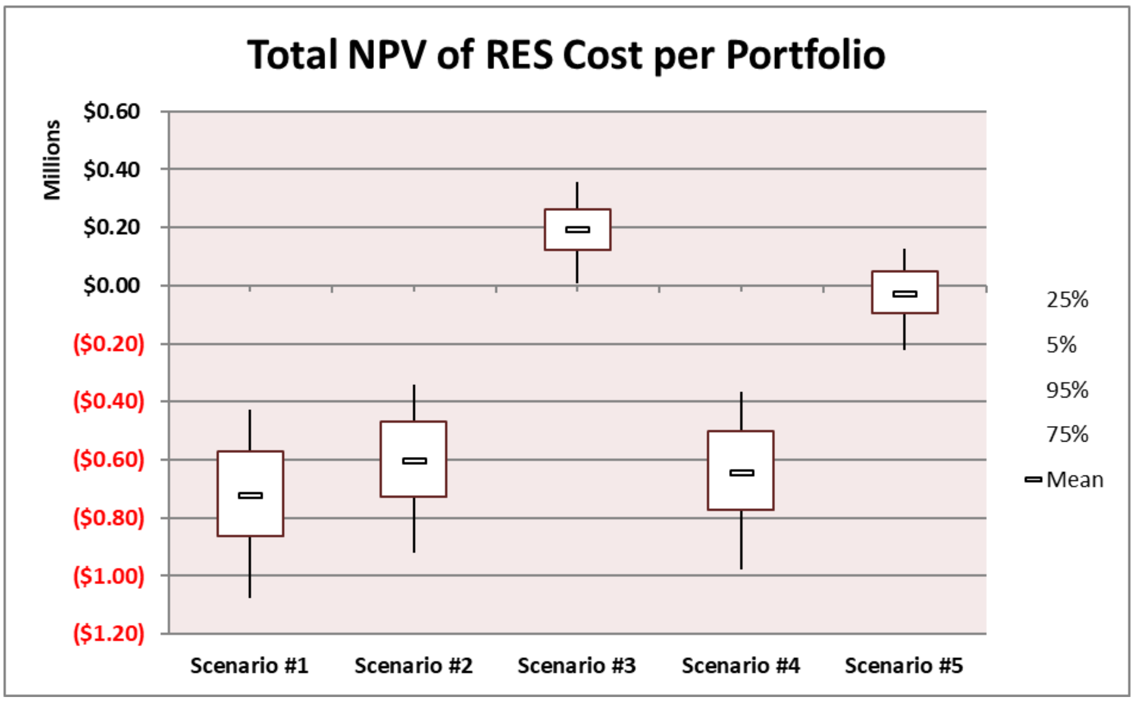
II. Scenario 5 is the current portfolio with a 1MW purchase of an existing hydro project, and .5MW of a large ISO- NE scale solar project. This provides the greatest coverage with the less risk due to a low standard deviation. The renewables all help comply with HPE's RES.

III. Scenario 2 is the current portfolio with a 1MW purchase of an existing hydro project. This scenario provides RES compliance, but limits the resources within the portfolio to just one large renewable.

These select scenarios provide an analysis of both RES and energy coverage at various levels and price. Using the previously mentioned four major criteria during evaluations allows Hyde Park to fulfill its goals of compliance and risk coverage in order to help provide reliable, reasonably priced energy. However, one must be cognizant of the fact that with more renewables, although helpful towards RES, there is a reliability risk as well as price risk to HPE's energy cost.

The following Figure 3 shows the results of the simulations in a "box plot"[1] format, which provides a quick visual summary of the mean value, the minimum and maximum values, and the relative amount of relative variation around the expected cost of RES to Hyde Park for each scenario.

Figure 3: 20-year Total Portfolio Cost Comparison for each Portfolio's RES NPV

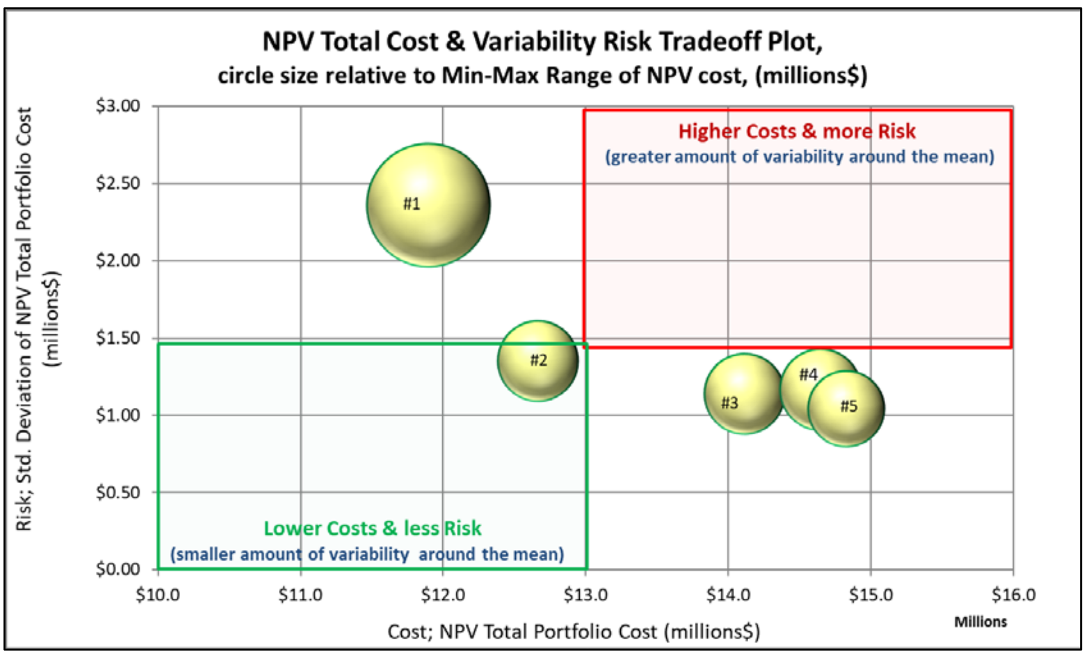


[1] "Box-and-Whisker" diagram, the white area, or the "box," represents the upper and lower quartiles (25th and 75th percentiles) of values, the black line is the 50th percentile of the data, and the thin black lines, or the "whiskers," represent the minimum and maximum values of the sample data.

Another method for comparative tradeoff analysis is to rank the portfolios by their standard deviations and then plot them in "risk/return"[2] space. This plots the expected values along the x-axis and the risk on the y-axis. For this analysis a "bubble" chart was used, where each "bubble" is a point on the chart and represents a portfolio's relative position based on its respective expected value, X, and standard deviation, Y.

This allows for a comparison and evaluation of portfolios based on their location on the chart – namely, which quadrant they fall within from the output of the modeling. For example, if comparing portfolios on risk vs. least cost, the lower left quadrant should contain the portfolios with both lower costs and risk, and the upper right quadrant should hold the higher cost and higher risk portfolios. The additional benefit of using a bubble chart is that the relative size of each bubble also represents that relative variation of each portfolio. Not only does the quadrant show a portfolio's merit, but displays the size of a portfolio's bubble according to its relative risk. Figure 4 shows the bubble plot comparison for least cost and risk.

Figure 4: Risk/Cost Tradeoff Bubble Plot



[2] "risk/return space" is term used in Portfolio Theory when finding the Min-Variance portfolio, where "return" is term used when portfolio consists of equity assets; in the IRP context we use the implied improvement (savings/benefit) in Total Cost metrics by pursuing an alternative resource portfolio as a proxy for "return".

A.2.5 Hyde Park's Target Resource Portfolio

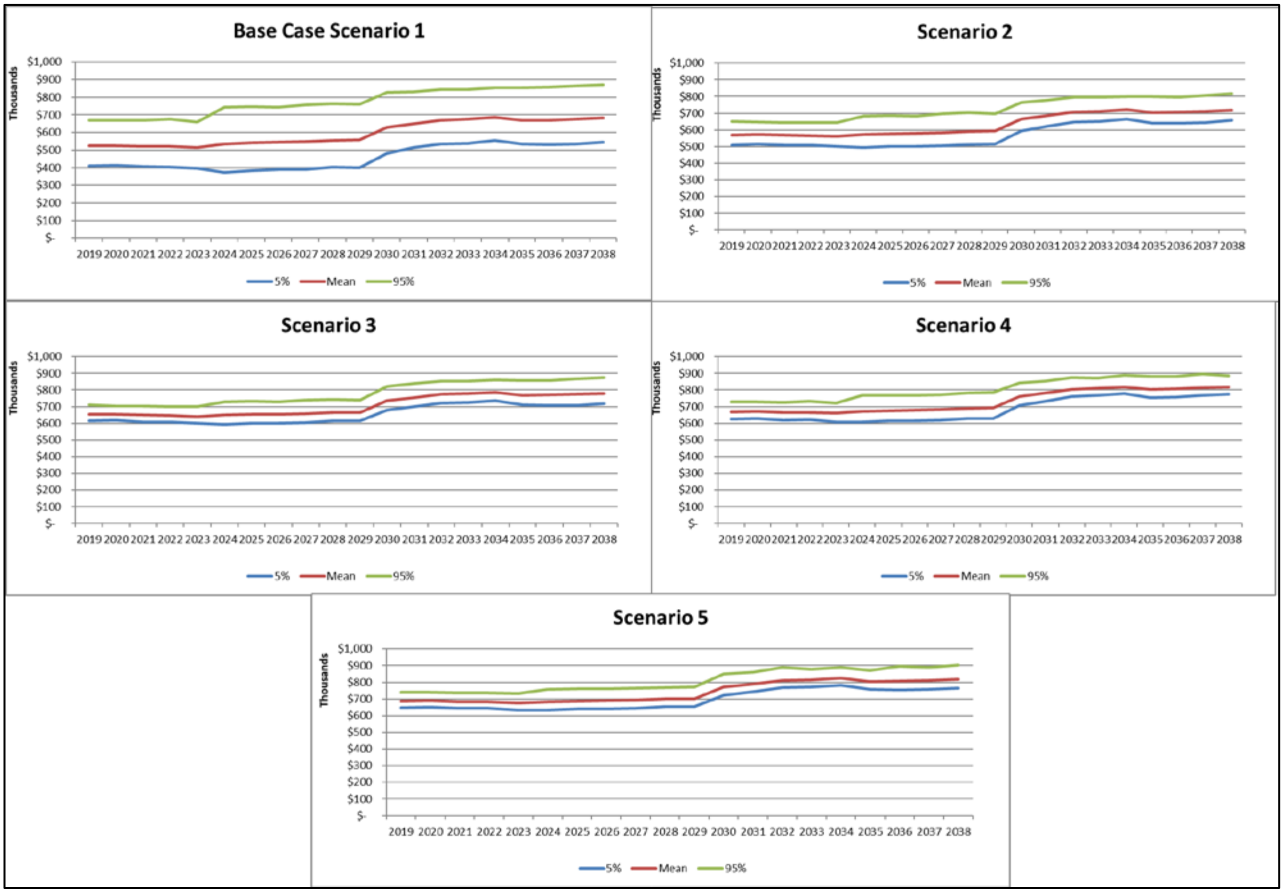
Based on the comparative analysis, the optimal portfolio is Scenario #2 for HPE's Integrated Resource Plan. The caveat is that specific resource volumes will be determined relative to Hyde Park's load requirements throughout the term of this plan. These volumes will need adjusting to effectively balance the cost and environmental performance while avoiding the purchase of too many resources at certain times of the year. Material changes to Hyde Park's load, whether efficiency driven or not, will have an impact on the volume and nature of new resources pursued.

Hyde Park's optimal Integrated Resource Plan:

Portfolio 2 = Hyde Park's current existing resources, 1MW of an existing hydro PPA (Unit is considered to be a Tier I qualified), and without a regularly planned schedule of forward market purchases, market purchases will be dictated by the dynamics of HPE load and rate stability considerations.

The results point to the enhanced economic and environmental performance that is achievable by allocating resources to one of the alternative portfolios. An expected performance, such as lower average cost and lower greenhouse gas emissions, has a more reliable estimation when choosing resource combinations that exhibit relatively lower values of variations in the sample data. The most competitive portfolios strike a balance with resources that improve the environmental performance towards Vermont's Renewable Energy Standard and take advantage of the current market environment, which provide lower costs over time and across various market environments. Figure **5** shows how the selected IRP portfolio (Scenario #2) expects to enhance Hyde Park's annual cost structure over the next 20 years.

Figure 5: 20 Year Annual Energy and Total (Inclusive of RES Compliance Costs) Costs of IRP and Competing Alternate Resource Portfolios



The plan incorporates the following time line and action points:

1. Continue to explore ways to promote energy transformation projects and conservation for Tier III compliance purposes.
2. Monitor load growth or contraction on an ongoing basis.
3. Continue market purchases as needed in a low commodity price environment over the next several years.
4. Continue to review renewable resource alternatives, including wind, biomass, and hydro, to both diversify and comply with RES within HPE's portfolio. Technology improvements, the relative cost of market power, i.e. higher fossil fuel, and renewable energy credit prices will make these resources more attractive and affect their reviews.

5. Continue to procure short-term market contracts as needed to mitigate Hyde Park's exposure to short-term price volatility and to enhance rate stability.

B Introduction

B.1 Overview of the Village of Hyde Park Electric Department

The Village of Hyde Park, located in Lamoille County, incorporated in 1895 to provide electric street lighting to the Village and became the first in Vermont to use electricity for heating in 1899. Over the years, the service territory expanded to provide electric service beyond Village boundaries to North Hyde Park and a small section of the Town of Johnson. The area of the service territory is approximately 18 square miles.

HPE serves approximately 1,398 retail customers. The system's largest electrical customer is Lamoille Union High School, and in addition serves the Hyde Park Elementary School, Lamoille County Courthouse, and the North Hyde Park National Guard Training Facility. Hyde Park connects to the transmission system of Green Mountain Power (GMP).

Village resources, labor, expertise, vehicles, tools, equipment, IT hardware, software, storage and workspace are effectively utilized and accounted among multiple municipal functions, to include the electric department, the water department, the wastewater department, and Village municipal services such as planning and zoning.

Resiliency is important to the Hyde Park community. At the May 2014 Village Annual Meeting, a progressive resolution was presented by the Board of Trustees/Electric Commission and unanimously adopted. The resolution: "Shall a community resiliency program be created for the purpose of promoting locally generated electricity by the strategic installation of solar energy generation for use by Hyde Park Electric and promoting efficient electric technologies, which program shall be funded through a combination of grant awards, private investments, borrowing, and Electric Department revenue."

Hyde Park is a stable community. From 2014-2018, the number of retail customers increased by 1.6% while retail sales decreased by 1.1%. The following three tables show the annual system peak demand, number of retail customers, retail sales.

The following three tables show the annual system peak demand, number of retail customers, retail sales.

Table 2 Annual System Peak

Peak Demand	2012	2013	2014	2015	2016	2017	2018
kW	2,272	2,447	2,424	2,352	2,948	2,496	2,328
Date	1/3/2012	12/17/2013	1/2/2014	2/15/2015	8/8/2016	12/31/2017	12/18/2018
Hour	18	19	18	19	13	18	18

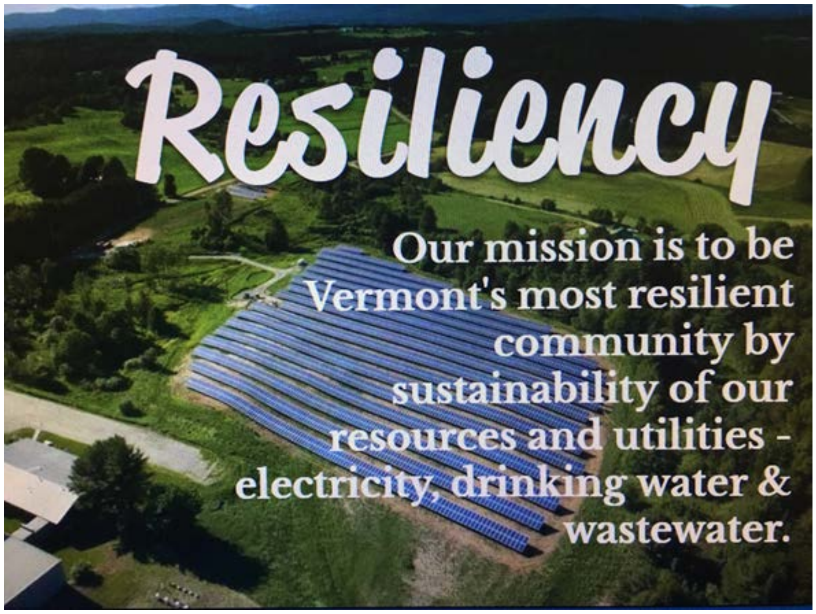
Table 3 Number of Retail Customers

Number of Retail Customers	2014	2015	2016	2017	2018
Residential (440)	1,165	1,179	1,172	1,172	1,184
Small C & I, 1000 KW or less (442)	130	131	133	133	129
Public Street & Highway (444)	2	2	2	2	2
Other Sales to Public Auth. (445)	36	26	38	38	36
Interdepartmental (448)	50	49	50	50	47
Total	1,383	1,387	1,395	1,395	1,398
Year to Year	0.7%	0.3%	0.5%	0.0%	0.2%

Table 4 Retail Sales

Retail Sales (kWh)	2014	2015	2016	2017	2018
Residential (440)	8,274,765	8,003,309	7,996,218	7,782,751	8,181,006
Small C & I, 1000 KW or less (442)	2,588,289	2,540,887	2,751,719	2,942,652	2,959,187
Public Street & Highway (444)	23,904	24,133	25,544	25,647	22,989
Other Sales to Public Auth. (445)	537,205	486,001	544,814	513,916	593,753
Interdepartmental (448)	26,148	23,962	23,956	23,247	16,729
Total	11,450,308	11,078,292	11.342,251	11,288,213	11,773,664
Year to Year	3.2%	-3.2%	2.4%	-0.5%	4.3%

Figure 6 Hyde Park's Waterhouse Solar Project



Hyde Park Solar, Waterhouse Solar Project
Commissioned August, 2016

HPE owns 100% of Waterhouse Solar Project of 1388kw DC / 1000kw AC generating capacity located at 900 Silver Ridge Road, Hyde Park VT 05655 and located within a 5.3 acre fenced area adjacent to a commercial and industrial facility named House of Troy. Project financing is by U.S. Treasury Department, Clean Renewable Energy Bonds.

B.1.1 Overview of the Village of Hyde Park

Hyde Park is the Shire Town of Lamoille County and the center of public life and amenities. The LVRT is a short walk from Main Street down Depot Street sidewalk.

Figure 7 Hyde Park's Village Pictures

[3]

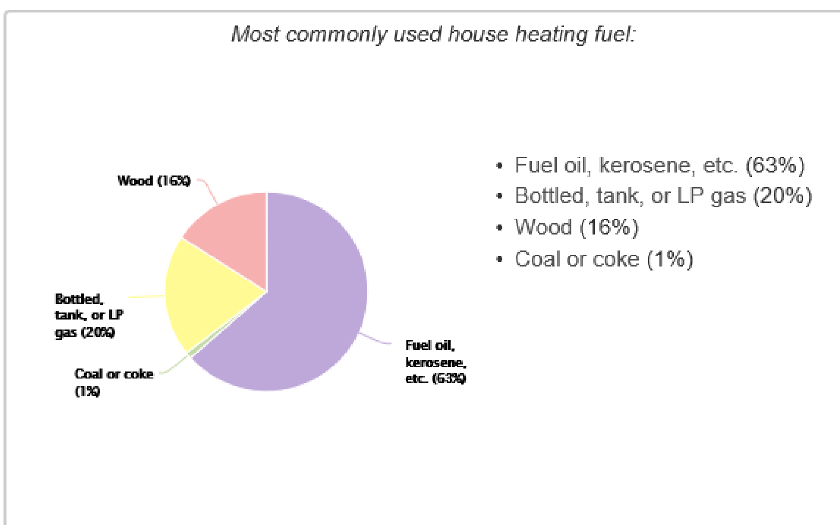
The Village of Hyde Park also capitalizes on the landscape's exceptional beauty and scenery, enabling HPE to develop an extensive year-round tourist economy. The annual transition from summer to fall with its beautiful foliage spectrum has become a popular tourist attraction. Year-round visitors are drawn by events in Mount Mansfield, Smuggler's Notch Resort and the Lamoille Valley Rail Trail. The Green River Reservoir State Park is a highlight of Spring, Summer and Fall.

[3] https://www.lvrt.org/

Figure 8 Fall View in Hyde Park

Since winter is a long season for HPE, it is important to understand the main fuel source that HPE's residences are using. HPE's housing heating source representation is found in Figure 9 below. These facts will become important when HPE looks for ways to implement energy transformation projects within the service territory for Tier III compliance.

Figure 9: Hyde Park's most commonly used house-heating fuel[4]



[4] http://www.city-data.com/city/Hyde-Park-Vermont.html

With 2008's capital improvement investment in the Lamoille county reliability project by VELCO, which upgraded 10 miles of new 115kW lines and added a new 115/34.5 kV substation, HPE elevated its dependability to its customers.

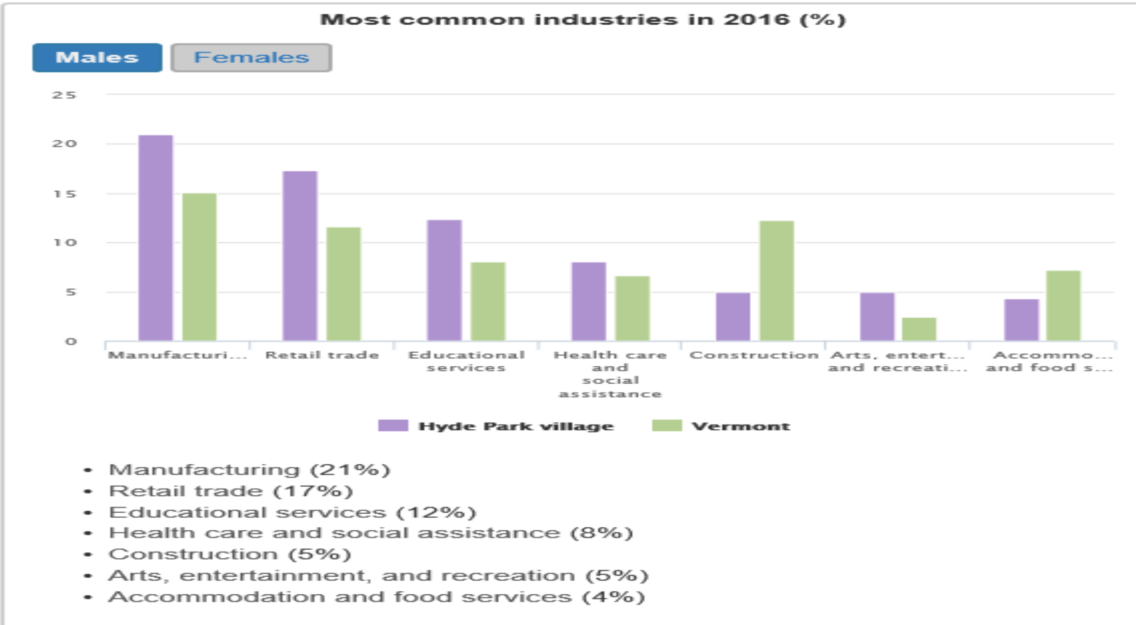
B.1.2 Hyde Park's Demographics

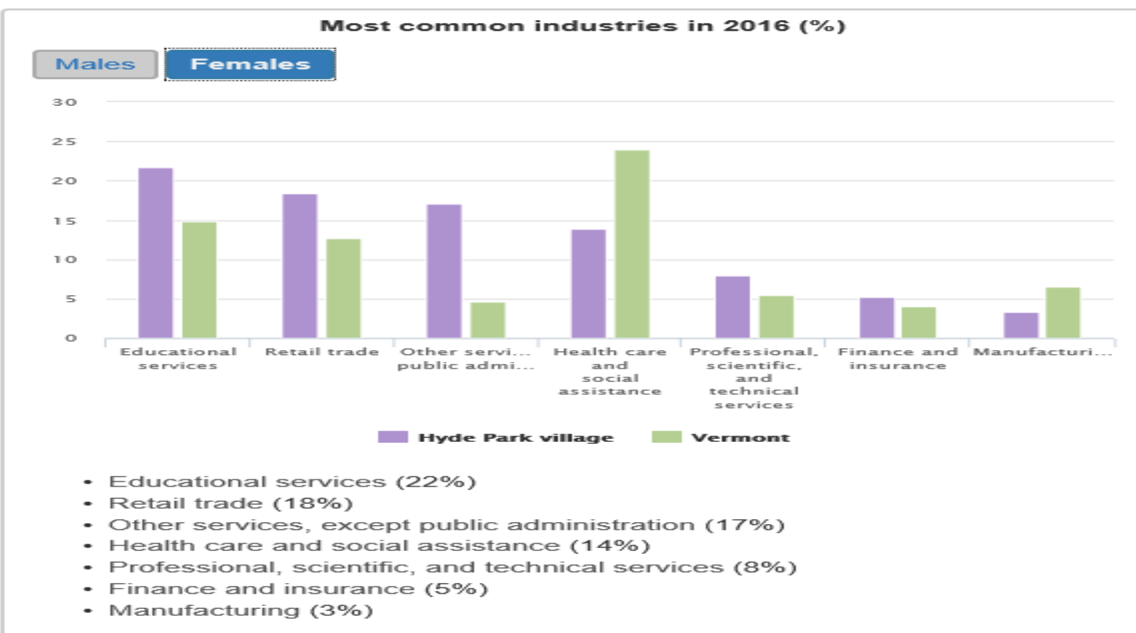
As of 2014[5], the population's median residential age was 41.8 years within Hyde Park. HPE has grown 18.3% since 2000. Within the occupied residential housing market, 82% owner occupied while 18% are renter occupied.[6] The median household income in 2016 was $72,147 (vs. $57,677 for Vermont), while the median house or condominium value was $214,605 (vs. $223,700 for Vermont). Hyde Park's main industry for jobs, for male is manufacturing while female's most common industry is Health care in 2016 as shown below in Figure 10, this is due to the heavy importance of tourism for the town. The second common industry is retail trade.

[5] http://www.city-data.com/city/Hyde-Park-Vermont.html

[6] http://www.city-data.com/housing/houses-Hyde-Park-Vermont.html

Figure 10: Common Industries for Males and Females in Hyde Park vs. Vermont [7]

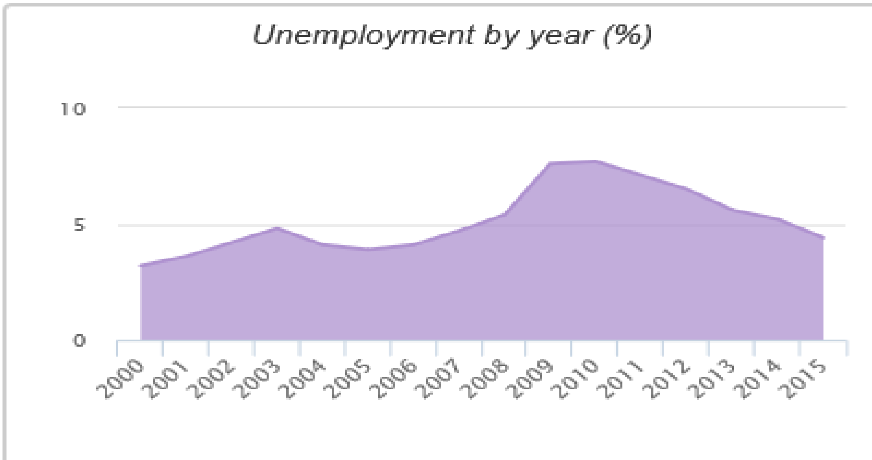




[7] http://www.city-data.com/city/Hyde-Park-Vermont.html

Hyde Park's 2015 unemployment rate was 4.4% (vs. 3.9% for Vermont). Hyde Park's unemployment history is found in Figure 11 below.

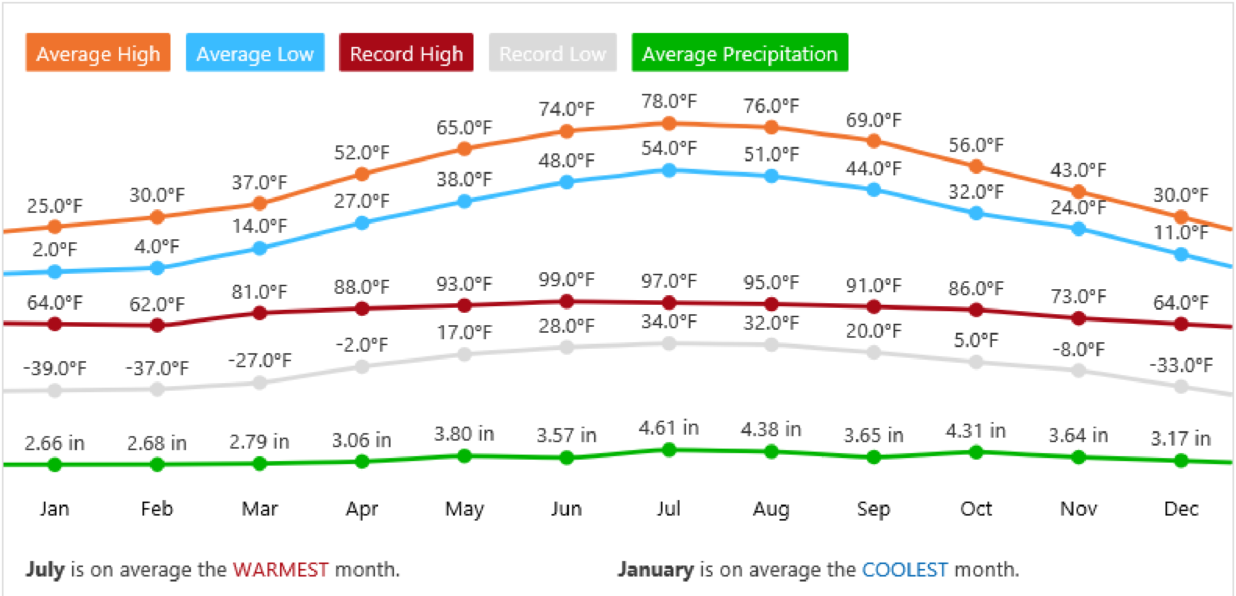
Figure 11: Hyde Park's Unemployment History



B.1.3 Hyde Park Climate

Hyde Park's climate is also important to take into consideration when planning future generation and/or location of generation. Hyde Park's average climate, found below in Figure 12 provides insight into which months are the highest heating and cooling driven months.

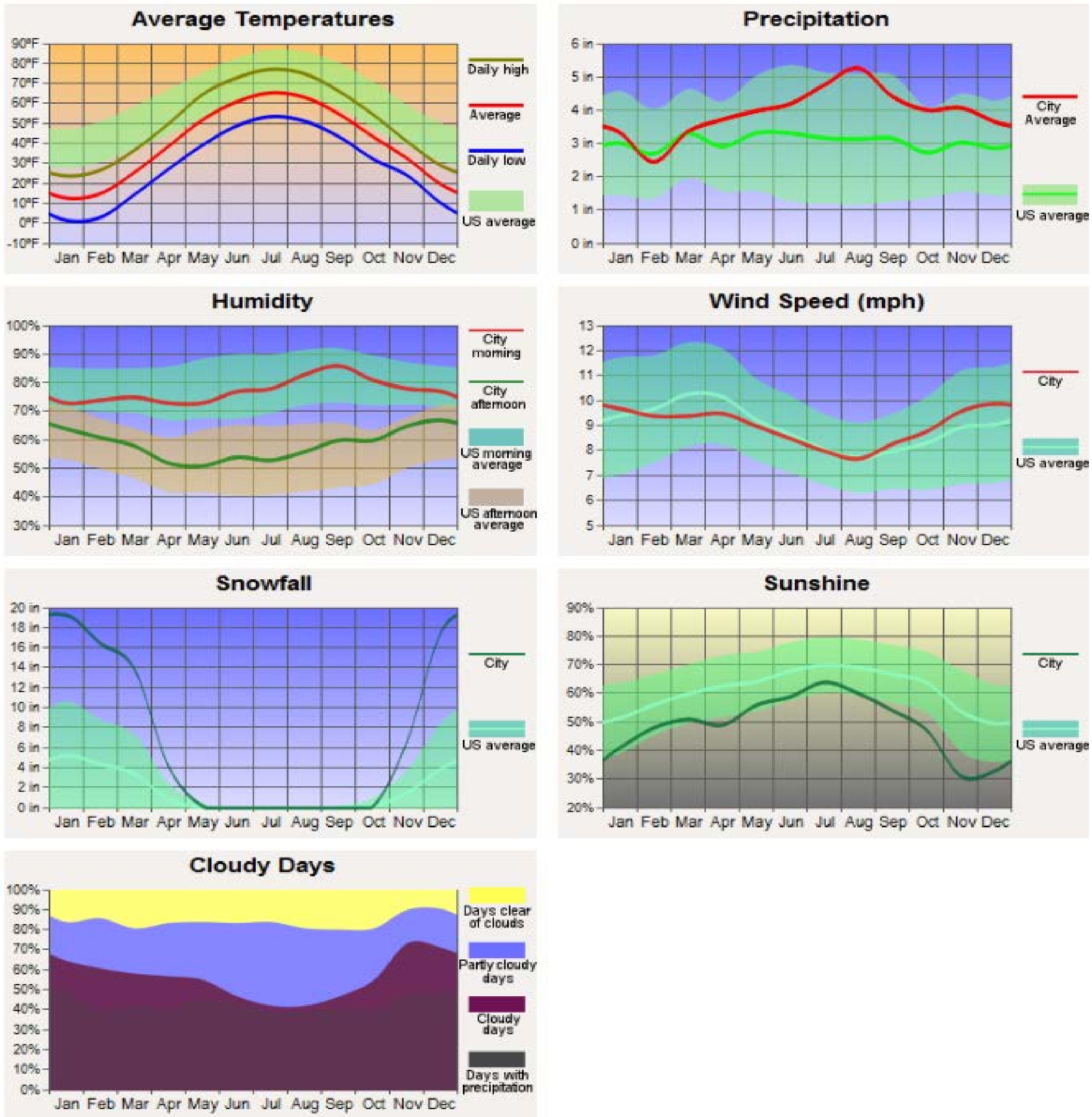
Figure 12: Hyde Park's Average Temperatures[8]



The data compiled by the city-data.com website, which uses over 4,000 weather stations, shown below in the graphs of Figure 13. By analyzing wind speed and cloud coverage, Hyde Park is able to make educated assumptions of resource optimization within Hyde Park. Although renewable generation has benefits to Hyde Park, it is important to choose the resource that will benefit Hyde Park the most by providing the greatest output.

[8] https://weather.com/weather/monthly/l/USVT0113:1:US

Figure 13: Average Climate in Hyde Park[9]



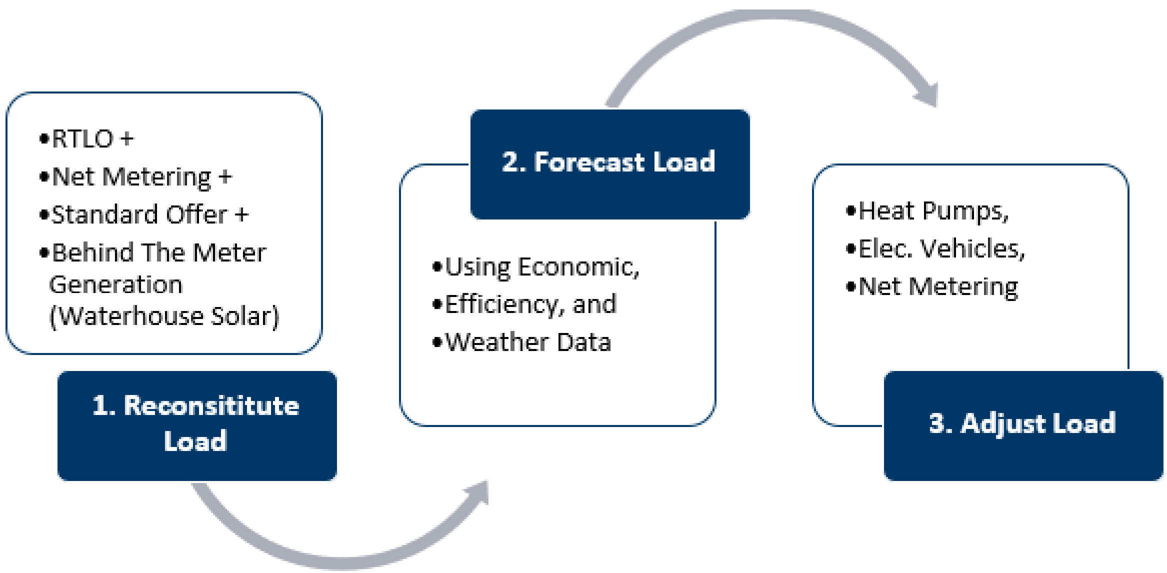
[9] http://www.city-data.com/city/Hyde-Park-Vermont.html

C Long Term Energy and Demand Forecasts and Scenarios

C.1 Demand Forecasting (Submitted by VPPSA.)

VPPSA uses Itron's Metrix ND software package and a pair of multiple regression equations to forecast Hyde Park's peak and energy requirements. The forecast methodology follows a three-step process.

Figure 14 Forecasting Process



C.1.1 Reconstitute Load

In the past, metered data at the system boundary (substation(s)) was used as the 'dependent' variable in the regression equations. Also known as the "Real Time Load Obligation" or "RTLO", this is the load that the utility is responsible for serving in ISO New England's wholesale markets. However, the growing impact of the net-metering and standard offer programs, as well as behind the meter generation, has effectively obscured the historical trends in the RTLO data. As a result, VPPSA "reconstitutes" RTLO by adding back net-metered generation, the generation from the Standard Offer Program and behind the meter generation. The resulting, reconstituted load is used as the dependent variable in the regression equations, and forms the historical time series data that the regression equations use to predict future loads.

The following table summarizes the data that is used to reconstitute RTLO.

Table 5 Data Sources for Reconstituting RTLO

Data Element	Source
Real-Time Load Obligation (RTLO)	ISO-NE
+ Net Metering Program Generation	VPPSA
+ Standard Offer Program Generation	VELCO
+ Behind The Meter Generation (Waterhouse Solar)	VPPSA

C.1.2 Forecast Load

The regression equations use a series of independent or "explanatory" variables to explain the trends in the reconstituted load data. The equations themselves consist of the explanatory variables that are listed in Table 6.

Table 6 Load Forecast Explanatory Variables

Data Category	Explanatory Variable	Source
Dummy Variables	These variables consist of zeros and ones that capture seasonal, holiday-related, and large, one-time changes in electricity demand.	Not applicable. Determined by the forecast analyst.
Economic Indicators	Unemployment Rate (%)	Vermont Department of Labor
Weather Variables	Temperature – 10-year average heating & cooling degree days.	National Oceanic and Atmospheric Administration (NOAA)
Energy Efficiency*	Cumulative EE Savings Claims (kWh)	Efficiency Vermont Report and Demand Resource Plan

*Peak Forecast only

The forecast accuracy of the regression model (energy) is very good. Based on monthly data, it has an R-squared of 96%, and a Mean Absolute Percent Error (MAPE) of 1.36 percent.

C.1.3 Adjust Load

Once the regression models are complete and the forecast accuracy is maximized, the load forecast is adjusted to account for the expected, future impact of cold climate heat pumps, electric-vehicles, and net-metering. Because the historical trends for these three items are still nascent, they cannot be effectively captured in the regression equations. In the case of net-metering, VPPSA used the most recent three-year average to determine the rate of net-metering growth in Hyde Park. For cold-climate heat pumps (CCHP) and electric vehicles (EVs), we used the same data (provided by Itron) that the Vermont System Planning Committee (VSPC) used in VELCO's 2018 Long-Range Transmission Plan.

C.2 Peak Forecast Methodology: The Peak & Average Method

The peak forecast regression model forecasts the load during the peak hour each day. Because utility loads are strongly influenced by temperature, this peak usually occurs during an hour of relatively extreme temperatures. In winter, this is during a very cold hour, and in summer it is during a very hot hour.

Unlike the energy forecast model, using average weather in the peak forecast model is not appropriate. Why? By definition, the coldest day and hour is always colder than average, and the hottest day and hour is always hotter than average. As a result, using average weather in the peak forecast model would result in a forecast that is bias and too low. In this context, the key question is, "How can historical weather data be used to develop an accurate representation of future weather, while still maintaining the extremes?"

The answer is the rank-and-average method, which is widely accepted[10] and effectively represents the random, real-life extremes in average historical weather. This method assigns a temperature to each day of the year that is representative of the average of the coldest (or hottest) days. It is important to highlight that the rank and average method produces a "50/50" forecast. While one may expect this to be a method for forecasting extreme weather conditions, in reality extreme weather is normal.

The accuracy of the peak forecast regression model is good. Based on daily data, it has an R-squared of 88%, and a Mean Absolute Percent Error (MAPE) of 3.52 percent.

C.3 Energy Forecast Results

Table 7 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is nearly flat. After making adjustments for heat pumps (HPs), electric vehicles (EVs), and net metering, the Adjusted Forecast actually increases by 0.6 percent per year.

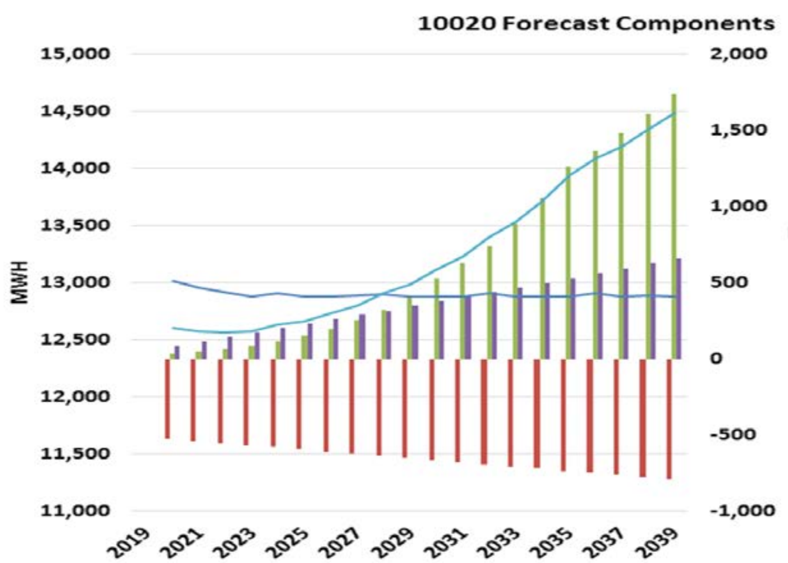
[10] For a more in-depth discussion of the method, please refer to Itron's white paper on the topic. https://www1.itron.com/PublishedContent/Defining%20Normal%20Weather%20for%20Energy%20and%20Peak%20Normalization.pdf

Table 7 Energy Forecast (MWh/Year)

Year	Year #	Regression Fcst. (MWh)	Heat Pump Adjust (MWh)	EV Adjust (MWh)	Net Metering Adjust (MWh)	Adjusted Fcst. (MWh)
2020	1	13,014	86	30	-525	12,604
2025	6	12,876	230	150	-593	12,663
2030	11	12,876	376	523	-663	13,111
2035	16	12,876	530	1,260	-733	13,933
2039	20	12,879	659	1,737	-788	14,486
CAGR		**-0.0%**	**10.7%**	**22.5%**	**2.1%**	**0.6%**

The Adjusted Forecast is the result of high compound rates of adoption (CAGRs) for heat pumps (10.7%) and electric vehicles (22.5%). But during the first ten years of the forecast, these two trends are more than offset by the net metering program, which grows by the historical three-year average of 2.1 percent per year. By year eleven, the impact of HPs and EVs is greater than the impact of net metering, and the cross-over point can be seen in Figure 15.

Figure 15 Energy Forecast (MWh/Year)



All of the trends in these adjustments are highly uncertain. However, they do offset each other, and their collective impact on the forecast is small. Specifically, their individual and collective impact represents fractions of one percent, which falls well within the forecast error (1.36%).

C.4 Peak Forecast Results

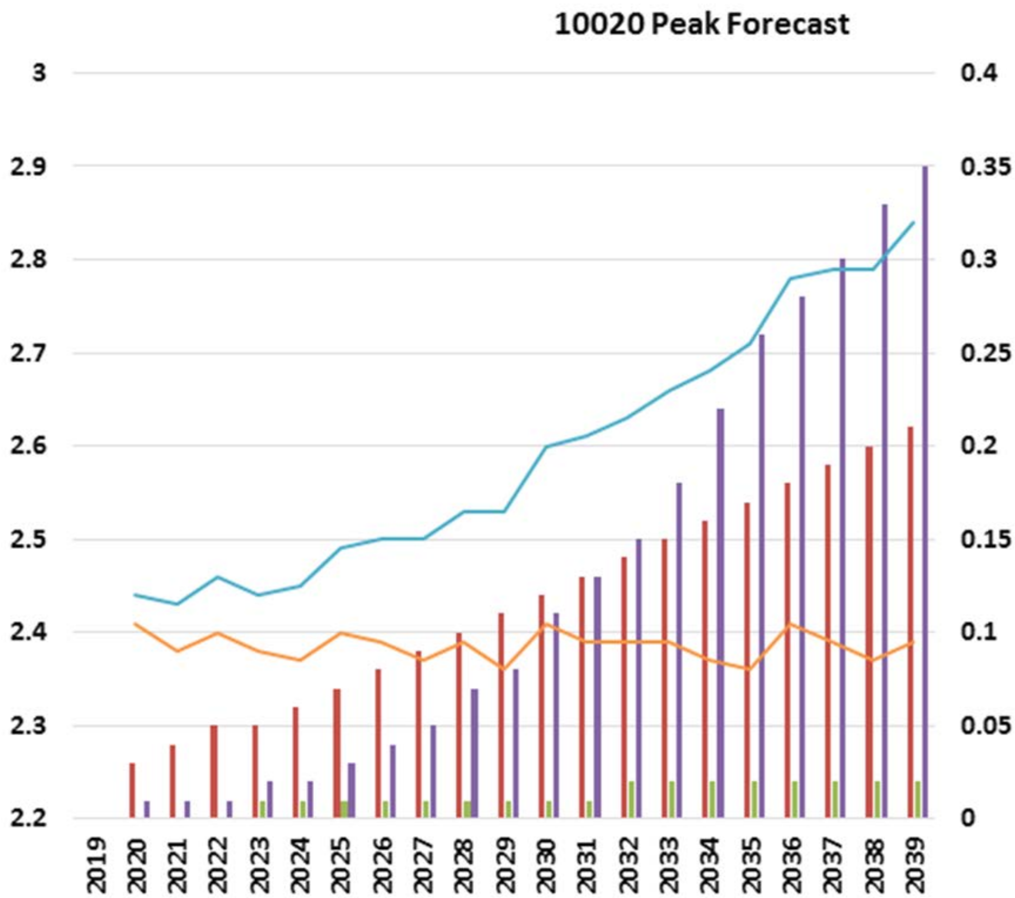
Below in Table 8 shows the results of the Regression Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is declining by 0.3 percent per year. After making adjustments for heat pumps (HPs), electric vehicles (EVs), and net metering, the Adjusted Forecast actually increases by 0.2 percent per year. Finally, the table shows that the timing of the Hyde Park's peak load is forecast to stay in the winter months, between hours 1800 and 1900.

Table 8 Peak Forecast (MW)

MMM-YY	Day	Peak Hour	Regression Forecast	Average EV	Average HP	Average Net Metering	Forecast Adjusted
Jan-20	1	18	2.41	0.000	0.030	0.000	2.440
Jan-25	1	18	2.40	0.020	0.070	0.000	2.490
Jan-30	6	18	2.41	0.070	0.120	0.000	2.600
Jan-35	7	18	2.36	0.180	0.170	0.000	2.710
Jan-39	23	18	2.39	0.240	0.210	0.000	2.840
CAGR			**-0.0%**	**18.0%**	**10.1%**	**0.0%**	**0.8%**

Early in the forecast period, the Adjusted Forecast exceeds the Regression Forecast, and this is the result of high compound rates of adoption (CAGRs) for heat pumps (10.1%) and electric vehicles (18.0%). Unlike the energy forecast, the net metering program does not offset the trends of these two impacts due to the peak falling, each year, at a time of minimal solar impact. This can be seen in Figure 16.

Figure 16 Peak Forecast (MW)



Because the system peaks are in the winter during the early evening hours, the impact of net metering on the system peak is necessarily limited. Therefore, the HP and EV trends are the drivers of peak load growth.

C.5 Forecast Uncertainties & Considerations

Despite strong growth in HPs and EVs, Hyde Park's electricity demand is expected to be quite flat over the forecast period. However, some uncertainties do exist.

Hyde Park presently has nearly three dozen net-metered customers. However, as solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If State policy continues to be supportive of net metering in this event, it could lead to a steep change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

A more realistic possibility is that a series of large net metered projects are built. While the addition of a large net metered project is not assumed in this forecast, the impact can be estimated. For example, in 2017 a 150-kW net metered project went online. The addition of one more 150 kW net metered solar projects would increase the base of installed, net metered capacity on the system (1361 kW as of 2019) by over ten percent, and would increase net metered generation by a similar percentage.

In addition, it is important to continue to monitor Hyde Park for significant customers that may go on or offline which may have a strong effect on both energy and peak values. While such utilities do not yet exist in Hyde Park, nor are they assumed to in this forecast, some VPPSA member systems include customers that, at times, excess half of the entire utility's demand. Should a customer of equivalent scale come online in Hyde Park, major changes may need to be made across many facets of Hyde Park's long-term outlook.

Lastly to touch on HPs and EVs one final time, it should be emphasized that these continue to be emerging technologies that are forecast to have a significant effect on Hyde Park's load in the future. Due to the emphasis of these technologies in the forecast, their growth will need to be monitored closely over the coming years to determine how that growth pairs with the forecasted growth. Should the forecast growth vs. actual growth diverge significantly, the likelihood of significant utility forecast error will increase.

D Portfolio Planning Approach and External Influences

D.1 Regional Resource Portfolio and Marginal Supply

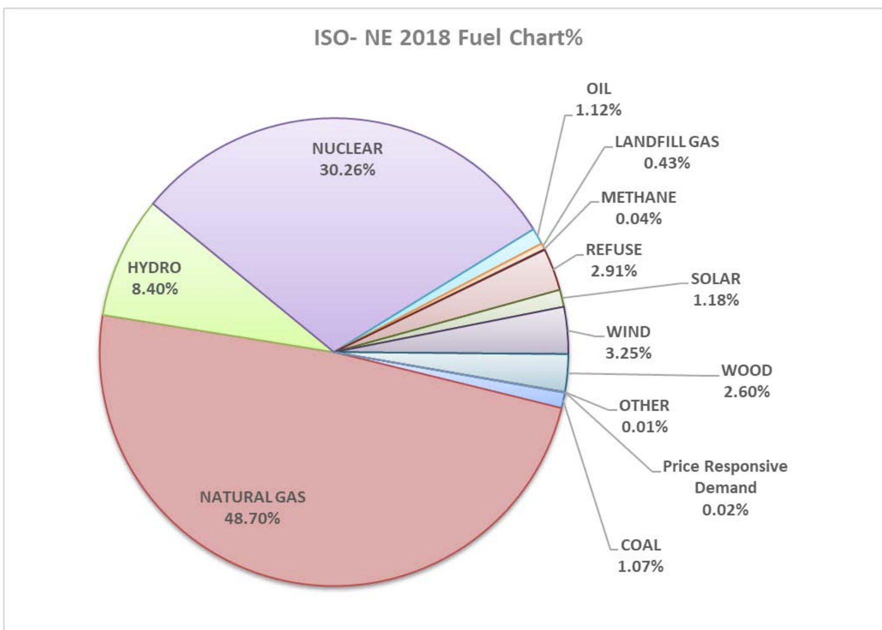
The New England ISO meets a majority of both its base load and its peak load with natural gas fueled units. As seen below in Figure 18, natural gas is about 48% of the resource fuel type used to cover the New England demand. New England has an increasing its reliance on natural gas because close to 50% of New England's electricity is generated from gas plants. This has increased the need for more pipelines. "New York and the six New England states are really ground zero for our pipeline problem" [11] This fact is the need for more pipelines is going to result in higher electricity prices. The New England options have decreased not that plants such as Vermont Yankee in Vernon VT, Salem Harbor in Salem MA and the Brayton Point in Somerset MA have all closed. The 65-acre site of Salem Harbor is now the location of Footprint Power's 674 MW quick-start combined-cycle gas turbine project. This gas plant is able to

[11] https://www.forbes.com/sites/judeclemente/2019/01/27/america-needs-more-oil-and-natural-gas-pipelines/#4d50ecfe452c

"provide efficient, low-emission power to New England while the renewable generating fleet is still relatively small."[12]

Figure 17 Model of the Footprint Plant

Figure 18: Supply Obligation by Fuel Type for Claimed Capability[13]



[12] http://footprintpower.com/

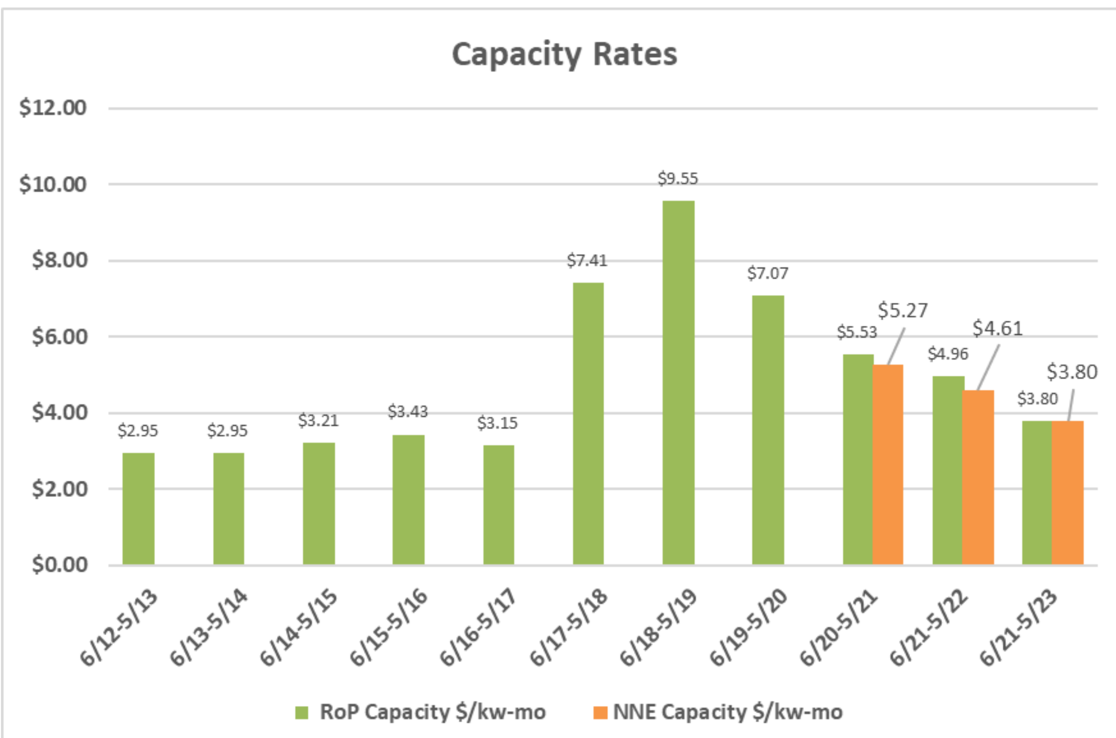
[13] https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load

D.2 Market Conditions

D.2.1 Capacity Market

The Forward Capacity Market (FCM) began on June 1, 2010. The FCM's goal is to acquire a sufficient amount of resources to meet the future demand. The FCM auctions take place three years in advance of actual settlement. The FCM auction designs clearing prices that will attract new generation and demand response assets as well as support the existing resources. The evolution with FCM has been within the zonal classifications. In the beginning, there was Rest of Pool and Maine. Beginning on June 1, 2016 there were Rest of Pool, Maine, Connecticut, and NEMA/Boston capacity zones. Currently, in the latest auction #13, there were Rest of Pool, Northern New England (NNE), and Southeast New England (SENE). Hyde Park has been in Rest of Pool until auction 11, where they now are under Northern New England. Historically, there has been price separation from zone to zone. The zones that were import constrained (NEMA) had larger clearing prices. Seen in Figure 19 are the clearing prices for the Rest of Pool and NNE Location that will affect Hyde Park's capacity charges.

Figure 19: Rest of Pool Capacity Auction Clearing Prices



Although the clearing prices increased in auction 8, Hyde Park did not see the price spike earlier as the NEMA location had. The zone location will also affect resource compensation, meaning where the unit resides will determine the compensation, which will not be a one for one on the load charge rates. This brings up the importance on self-supplying resources that are qualified to do so. In FCM 13, Hyde Park has self-supplied NextEra's Seabrook through VPPSA. This will guarantee a 1 to 1 offset of Hyde Park's load charges. Hyde Park's capacity portfolio can be seen in Figure 53. Hyde Park will assess the capacity market when researching different portfolio scenarios. Placement of generation and settlement of generation will come into play. Resources that directly offset peak usage for Hyde Park will be most attractive, because it will lower Hyde Park's obligation and give them the largest benefit. When forecasting the future capacity rates of the cost relations to portfolio scenarios for Hyde Park's IRP, the process included the analyzation of historical clearing prices and what factors drove those prices. In Table 9 below shows how much capacity was needed and how much the clearing prices were affected by new Demand resources and New Generation. In the auctions where new resources were needed the most, the clearing prices were greater. Currently the system has sufficient resource to meet electric demand in 2022-2023 and therefore it caused the lowest price settlement than the past three auctions.

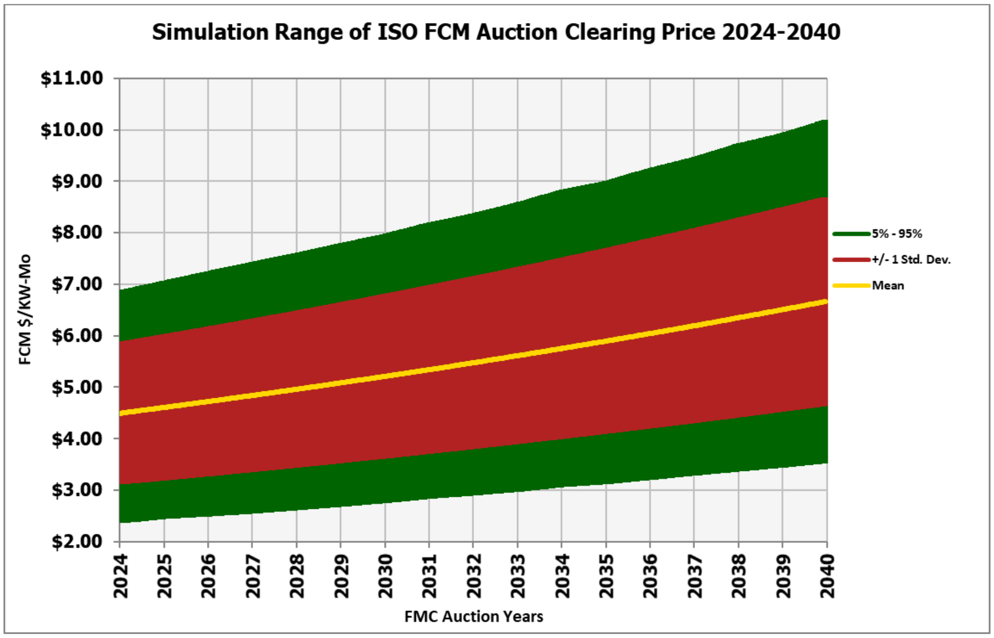
Table 9: ISO Auction Results FCA 1 through FCA 13[14]

AUCTION COMMITMENT PERIOD	TOTAL CAPACITY ACQUIRED (MW)	NEW DEMAND RESOURCES (MW)[1]	NEW GENERATION (MW)[2]	CLEARING PRICE ($/KW-MONTH)
FCA #1 in 2008 for CCP 2010/2011	34,077	1,188	626	$4.50 (FLOOR PRICE)
FCA #2 in 2008 for CCP 2011/2012	37,283	448	1,157	$3.60 (FLOOR PRICE)
FCA #3 in 2009 for CCP 2012/2013	36,996	309	1,670	$2.95 (FLOOR PRICE)
FCA #4 in 2010 for CCP 2013/2014	37,501	515	144	$2.95 (FLOOR PRICE)
FCA #5 in 2011 for CCP 2014/2015	36,918	263	42	$3.21 (FLOOR PRICE)
FCA #6 in 2012 for CCP 2015/2016	36,309	313	79	$3.43 (FLOOR PRICE)
FCA #7 in 2013 for CCP 2016/2017	36,220	245	800	$3.15 (FLOOR PRICE) NEMA/Boston: $14.99
FCA #8 in 2014 for CCP 2017/2018	33,712	394	30	$15.00/new & $7.025/existing
FCA #9 in 2015 for CCP 2018/2019	34,695	367	1,060	System-wide: $9.55 SEMA/RI: $17.73/new & $11.08/existing
FCA #10 in 2016 for CCP 2019/2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020/2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021/2022	34,828	514	174	$4.63
FCA #13 in 2019 for CCP 2022/2023	34,839	654	837[3]	$3.80

Energy New England utilized a Monte Carlo simulation technique to estimate future capacity clearing prices for Northern New England capacity zone. Simulation results are found in Figure 20 more information regarding the forecast can be found in G.4 Capacity modeling. Appendix D contains the simulation output using historical year weighting.

[14] https://www.iso-ne.com/about/key-stats/markets#fcaresults

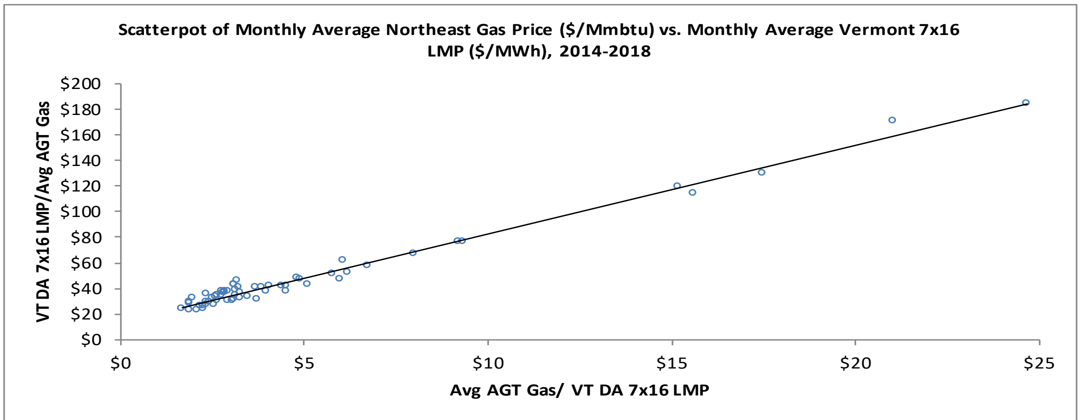
Figure 20: Forward Capacity Price Simulation Range



D.2.2 Energy Market

Within Hyde Park's scenario modeling, the Vermont load zone Locational Marginal Prices (LMP), where Hyde Park must purchase its load charges, are projected based on assumptions. These assumptions include natural gas and oil prices, as well as implied heat rates for the future. Calculations utilize regional delivered natural gas prices and implied heat rates due to the high frequency of natural gas fired resources setting marginal energy prices in New England. The link between energy prices in New England, specifically the Vermont Zone, is captured in Figure 21 which shows a .990 correlation between Vermont Zone 5x16 monthly average LMPs with monthly average northeast delivered natural gas prices.

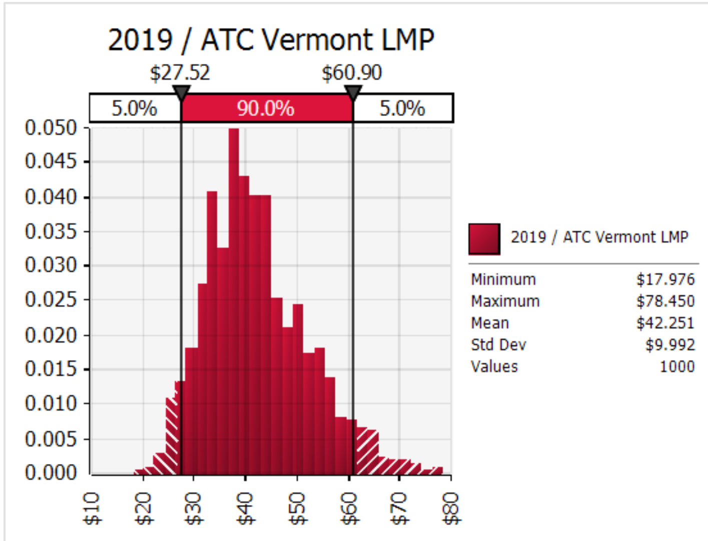
Figure 21: Vermont LMP Scatterplot Correlation to Northeast Natural Gas Prices



Correlation	0.9906473

The aforementioned assumptions construct Energy New England's forward curve of power prices in New England. In the portfolio optimization model, this forward curve is set to a mean (*expected* outcome); then, by modeling the historical periodic movement of LMP at the Mass Hub and the Vermont nodal basis, the model produces 1000's of simulations of LMP at the Vermont Load Zone. The simulations become a range of probabilistic outcomes (bucketed into percentiles) of simulated LMPs around the forward curve (the mean) to determine the probabilistic costs for open market purchases. Hyde Park's chosen portfolio scenario and future resource decisions will influence the nature of its interaction with the spot market. Hyde Park is able to reduce its spot market activities by procuring renewable resources and short and longer-term market purchases. Below in Figure 22 is the simulation results for Vermont and Mass Hub Around the Clock's Locational Marginal Price used in the base case data set.

Figure 22 2019 Forward VT and MA Hub LMP



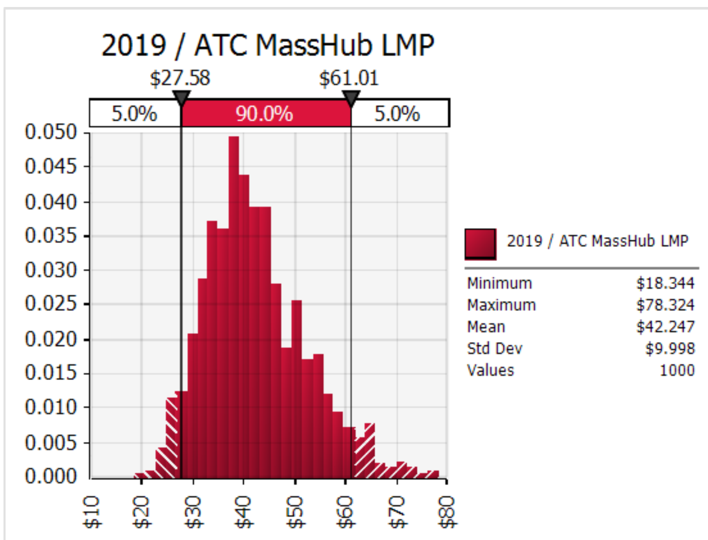


Figure 23: ISO New England HUB PEAK FWD CURVE HISTORY

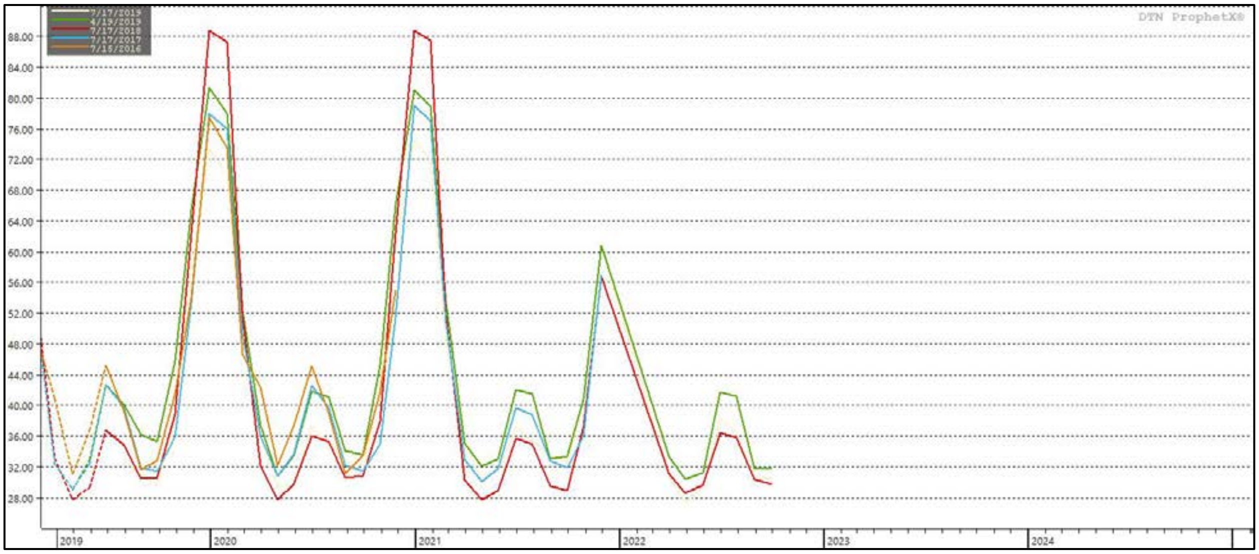


Figure 24: Mass Hub ATC LMP, Monthly Simulated Range Jan 2019 to Dec 2039

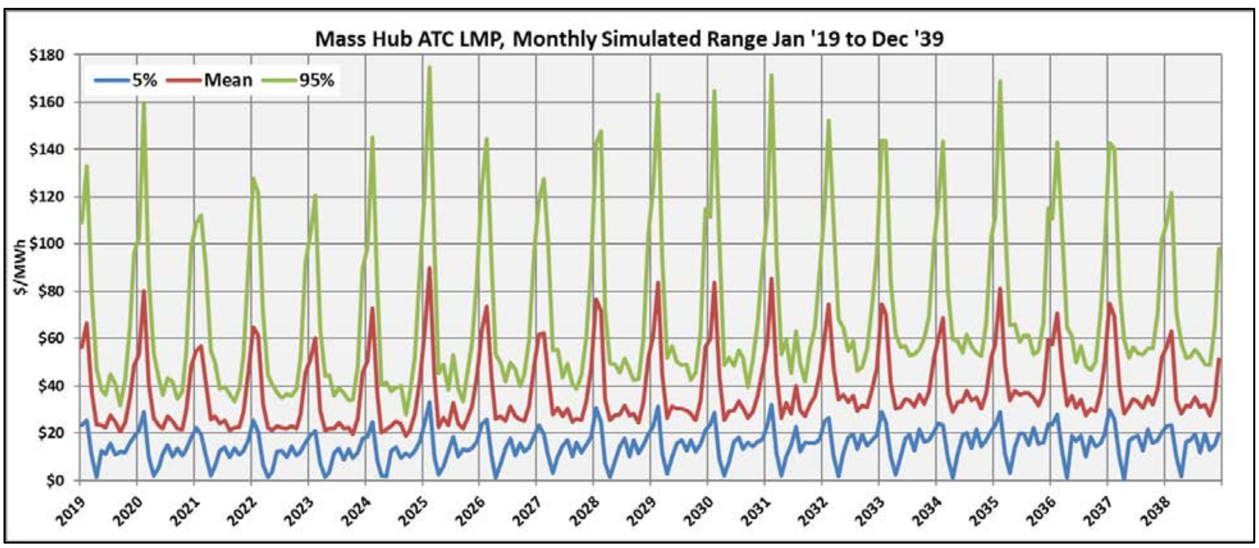


Figure 25: Vermont Zone ATC, Monthly simulated Range Jan 2019 to December 2039

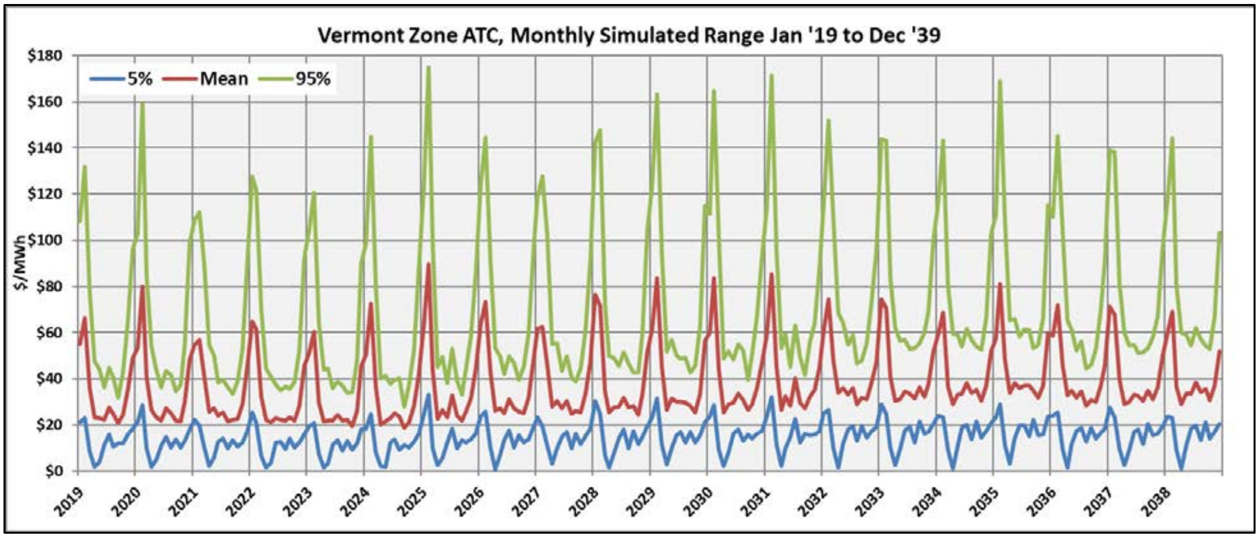
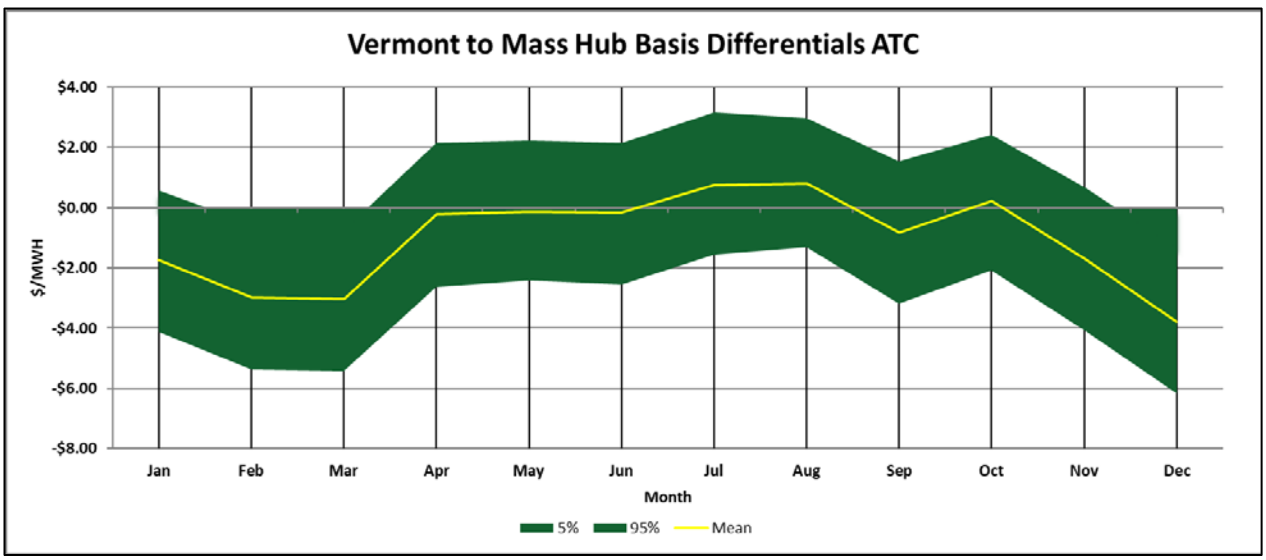


Figure 26: Vermont to Mass Hub Basis, Monthly Simulated Range, ATC



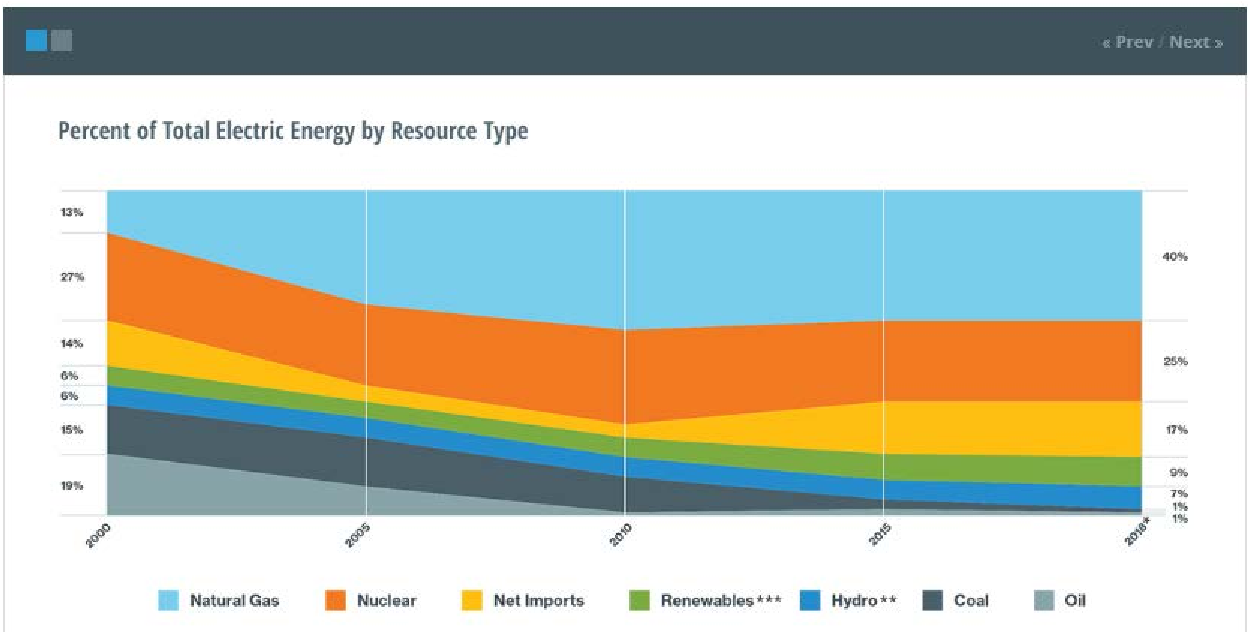
D.2.3 Natural Gas in New England

D.2.3.1 Reliance on Natural Gas for Electricity Generation in the Northeast

Over the last two decades, the reliance on natural gas for electricity generation has grown significantly in the Northeast; going from 13% to 40% share of the region's total electricity generation. As of 2018, over 40% of regional electricity generation was reported to be fueled primarily by natural gas. In 2018 natural gas was 35.1% of the share of the total primary fuel used for power generation in the United States, Coal was second at 27.4%.[15]

The predominant reason for natural gas surpassing coal as the fuel of choice for a majority of electricity generation regionally has been due to the development of increased access to low-cost natural gas (resulting from improvements in drilling technologies such as horizontal drilling and hydraulic fracturing) from the Marcellus Shale and other regional shale plays within the Appalachian Basin. Furthermore, environmental policies such as the Regional Greenhouse Gas Initiative as well as state-driven renewable portfolio standards have also contributed to the dwindling reliance on coal throughout the region.

Figure 27: New England Resource Mix – Percent of Total System Capacity by Fuel Type[16]



D.2.3.2 Market Fundamentals Influencing Spot and Forward Pricing of Natural Gas and Wholesale Electricity in New England

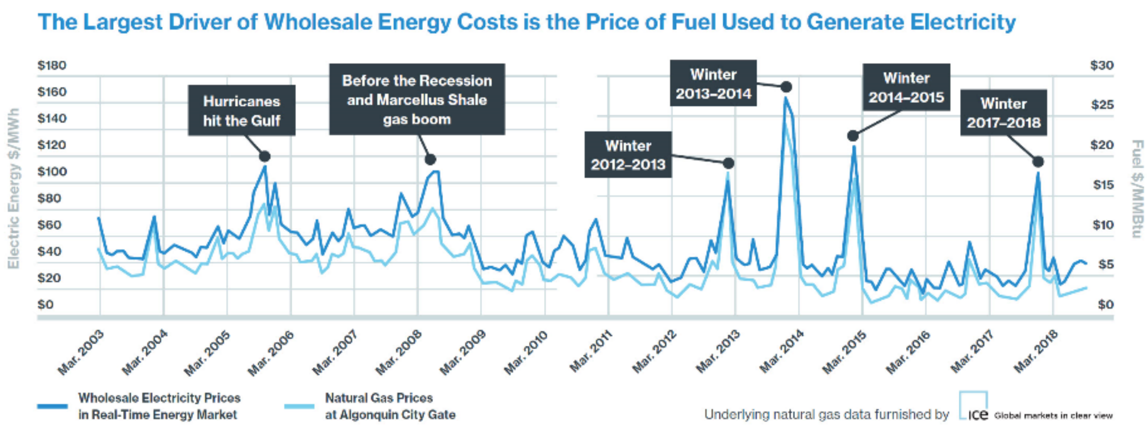
With natural gas positioning itself as the popular fuel source for electricity generation in the Northeast, it has subsequently become the marginal fuel source for wholesale electricity pricing. When low-cost natural gas delivered from the Algonquin City Gate is readily available and not in exceptionally high

[15] https://www.eia.gov/tools/faqs/faq.php?id=427&t=3
[16] https://www.iso-ne.com/about/key-stats/resource-mix

demand, this relationship between wholesale electricity prices and relatively low-cost natural gas is favorable to wholesale electricity consumers. However, natural gas remains one of the most volatile commodities in which its price can change frequently and materially. The market fundamentals of supply and demand, which are mostly driven by seasonal weather cycles and production/storage data, largely influence the spot and forward market pricing of natural gas. Further augmenting the volatility of natural gas prices in the Northeast are seasons that induce significant heating/cooling demand, during which the availability of natural gas is not a certainty.

The preeminent issue in the Northeast, which most notably reared its head in the winter of ‘13/’14 (due to the Polar Vortex), is that of natural gas pipeline capacity constraints and their ability to plague the region’s wholesale energy markets. When pipeline constraints and/or periods of exceptionally high demand hit the region, the basis price (the cost of moving a commodity from point A to B - in New England’s case, moving natural gas from Henry Hub to the Algonquin City-Gates) increases, thus causing wholesale electricity prices to increase as well. Historically, the Northeast has experienced its most notable pipeline capacity constraints in the winter. However, the last several winters in New England have brought relatively mild weather, and in turn, the price spikes in the Algonquin City-Gates basis have been lower than in previous years, as shown in Figure 28 .

Figure 28: Link between Regional Prices for Natural Gas and Wholesale Electricity[17]



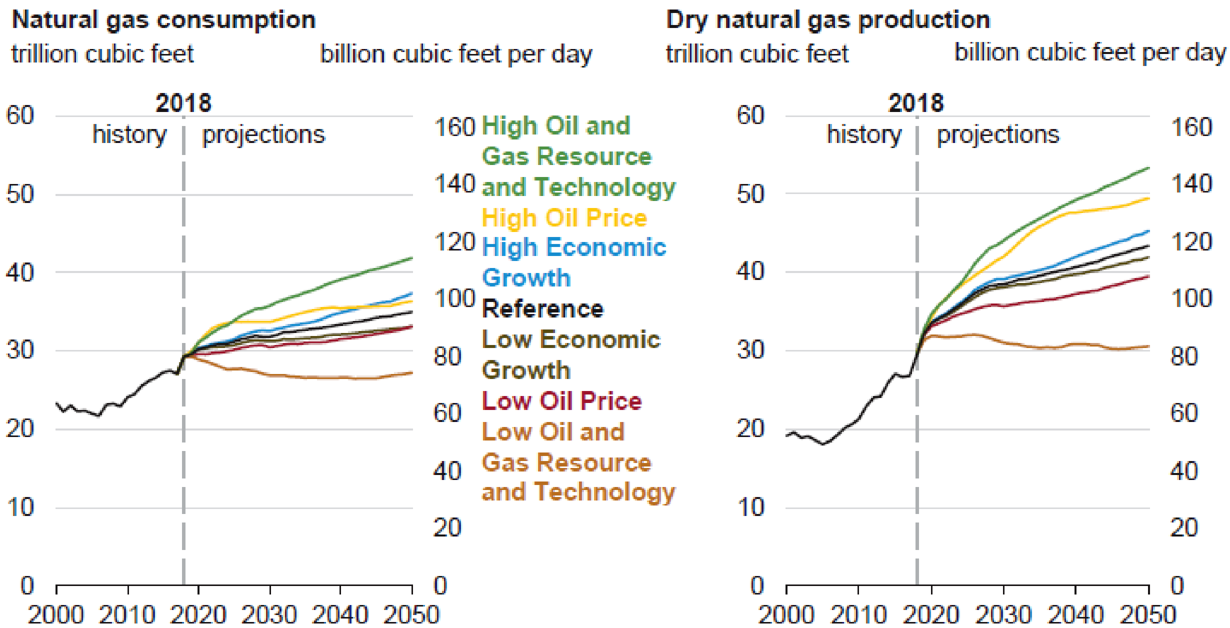
D.2.3.3 Natural Gas in New England - Summary

The Northeast saw an additional pipeline capacity built in 2018 and anticipates more expansion. The question is whether the capacity buildout can keep pace with demand. Increasing demand has come in several forms, for example, heating demand in the Northeast continues to be more reliant on natural gas as Local Distribution Companies (LDCs) continue to place customers on the preferred fuel. Demand increase is also a result of new natural-gas-fired generators replacing retiring non-gas-fired generation.

Natural gas prices have come down over the last several years, as seen in the “flattening” of the forward curve shown in Figure 30 . These price decreases are the result of enhancements in exploration and production technologies, increased supply and resources (i.e. Marcellus Shale play), and warmer-than-normal temperatures experienced over the past several winters. According to the AEO2019, shown in Figure 29 below, production is expected to grow and as exploration and production technologies become increasingly more efficient, thus driving prices down, so too will growth in consumption and net exports (including liquid natural gas (LNG)).

[17] https://www.iso-ne.com/about/key-stats/markets

Figure 29: EIA AEO2019 – Natural Gas Consumption and Production History/Projections[18]



It is hard to predict the levels at which natural gas spot and forward market pricing will reside since pricing will remain sensitive to advancements in E&P technology, the availability of resources, and seasonal weather cycles. However, ENE took into serious consideration the aforementioned market forces and scenarios when creating natural gas simulations.

[18] https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf

Figure 30: Natural Gas Forward Curve History

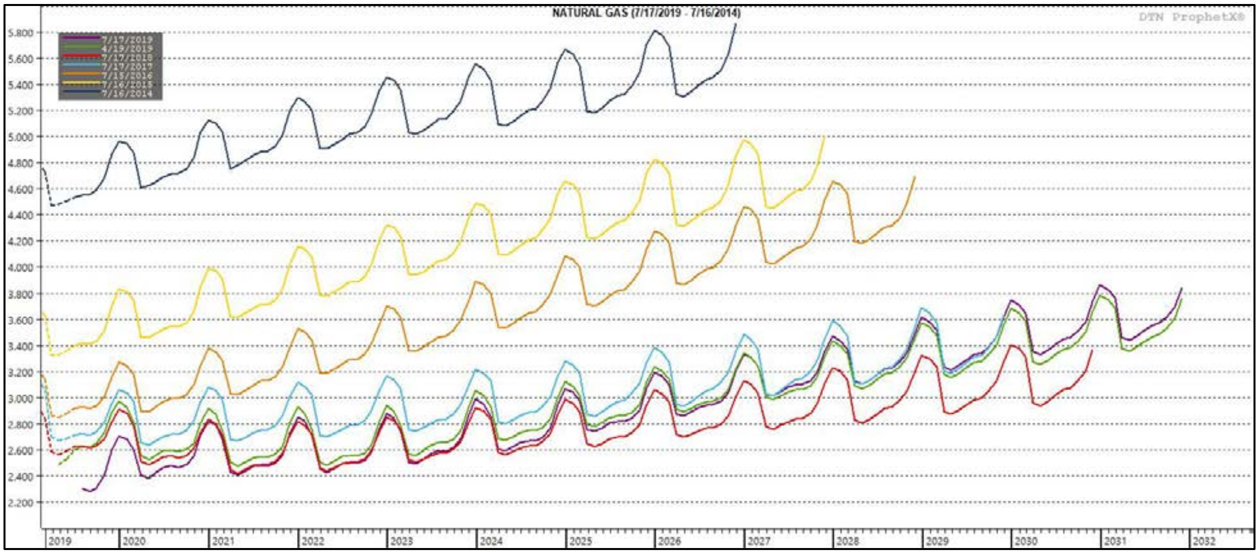


Figure 31: Natural Gas, Monthly Simulated Range Jan 2019 to Dec 2039

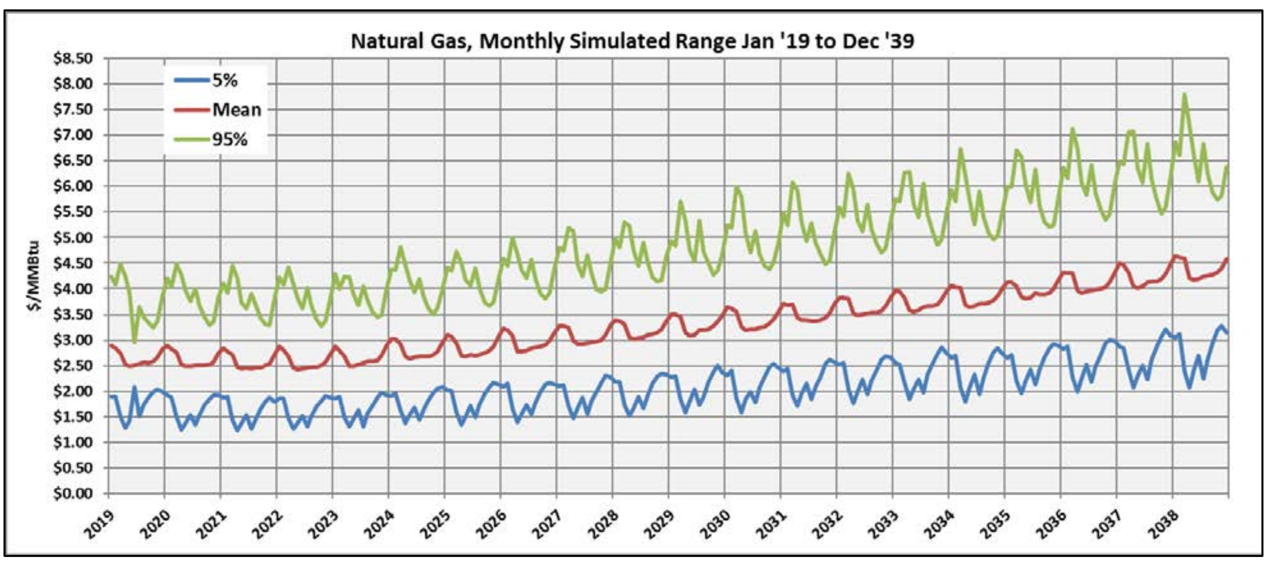


Figure 32: Algonquin Citygates, Monthly Simulated Range Jan 2019 to Dec 2039

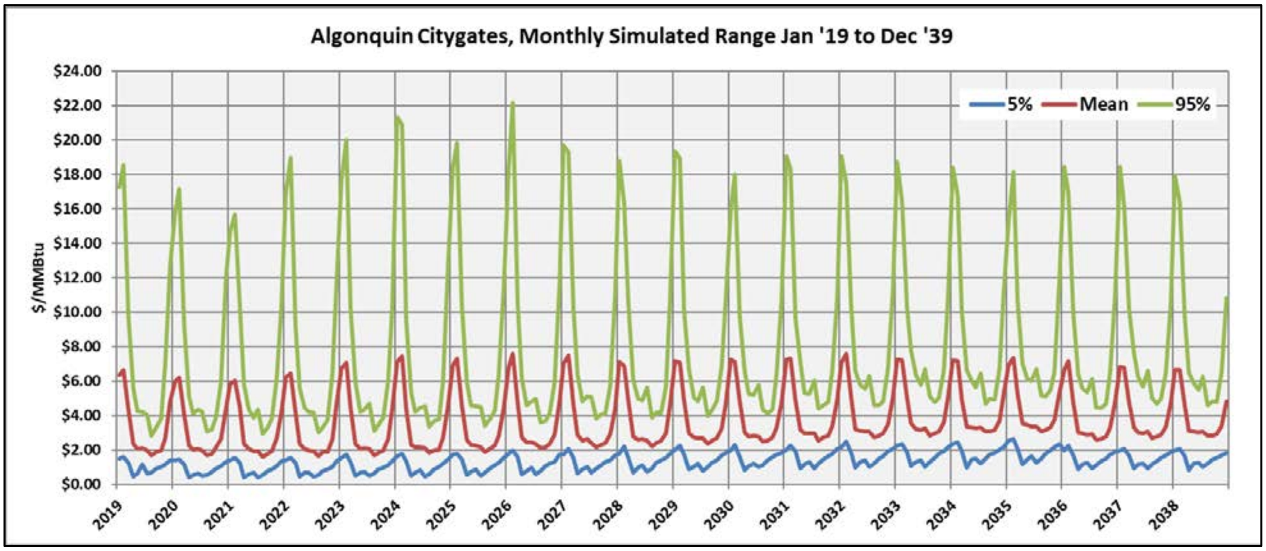
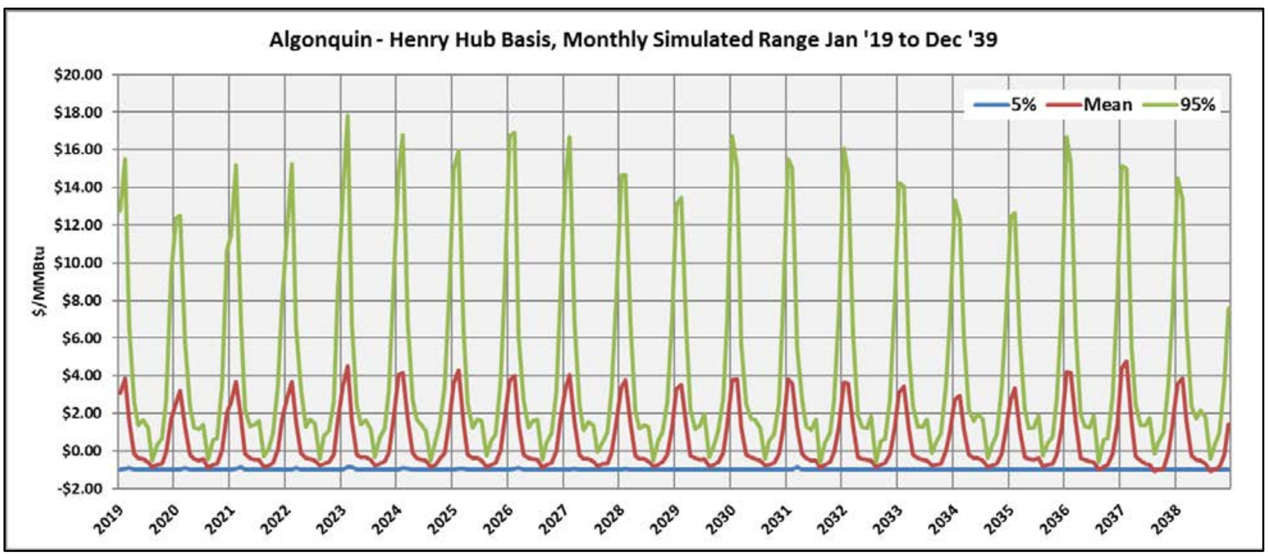


Figure 33: Algonquin to Henry Hub Basis, Monthly Simulated Range Jan 2019 to Dec 2039

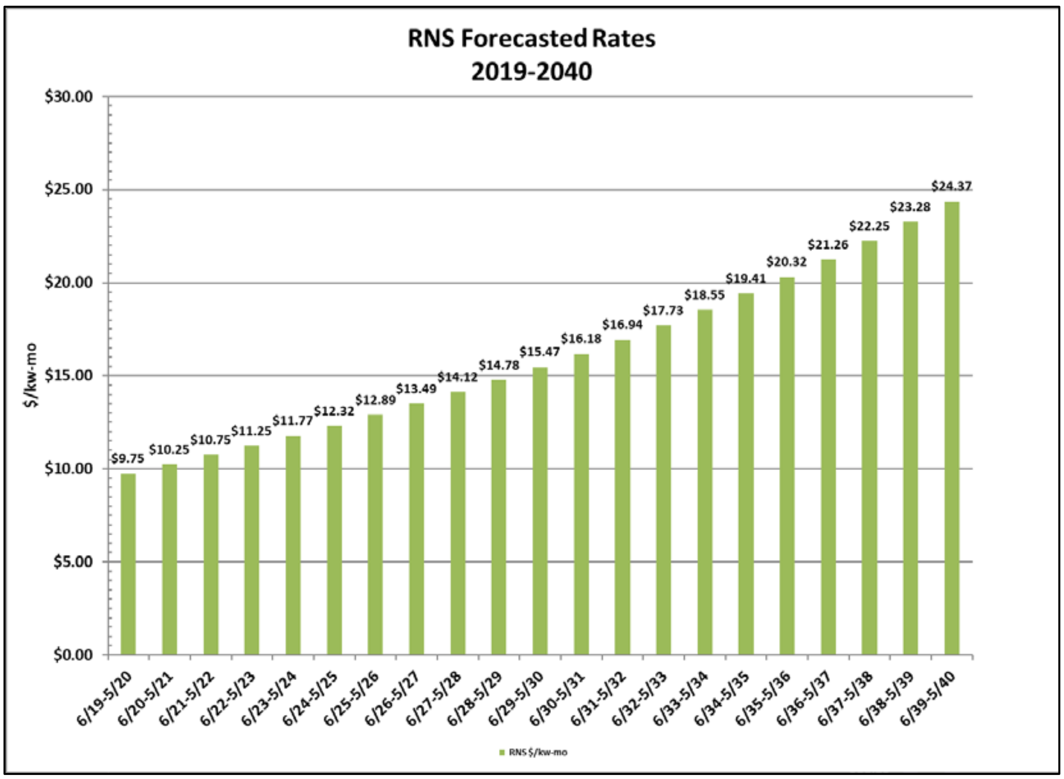


D.2.4 Transmission Market

The third largest piece of Hyde Park's New England Independent System Operator (ISO) costs is the Open Access Transmission Tariff (OATT). Within the transmission category are various ancillary charges, the largest of those being the Regional Network Service (RNS). RNS is the service over the Pool

Transmission Facilities, which the ISO provides to transmission customers to serve their loads.[19] These are monthly charges based on Hyde Park's regional network load value at VELCO's peak. Every summer, the ISO publishes the presentation from the Reliability Committee/Transmission Committee of the Rates Working Group for the RNS PRT Forecast. These going forward rates include current transmission projects. Figure 34 shows the latest published forecast on August 7 and 8, 2018 ISO presentation. The rates are steadily increasing, and therefore, Hyde Park's resource and efficiency become a larger importance. If Hyde Park can reduce consumption and do so at the critical coincident peak of VELCO, it could potentially save on its transmission charges to the ISO. Using the most recent forecasted rates and Hyde Park's three-year monthly peaks, ENE created a forecast of Hyde Park's transmission impact, shown in Table 10 . With projected RNS costs totaling over 1 million a year, Hyde Park's desired portfolio will have a mix of load reduction resources and energy efficiency load savings.

Figure 34: RNS Forecasted Rates



19 https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/oatt-schedule9-rns

Table 10: Hyde Park's RNS Forecast

HPE		
RNS Forecast		
Rate Year	RNS Rate $/kw-mo	Projected RNS Cost
6/18-5/19	$ 9.202	$ 253,970
6/19-5/20	$ 9.750	$ 269,084
6/20-5/21	$ 10.250	$ 282,883
6/21-5/22	$ 10.750	$ 296,682
6/22-5/23	$ 11.250	$ 310,482

D.3 Assessment of Environmental Impact

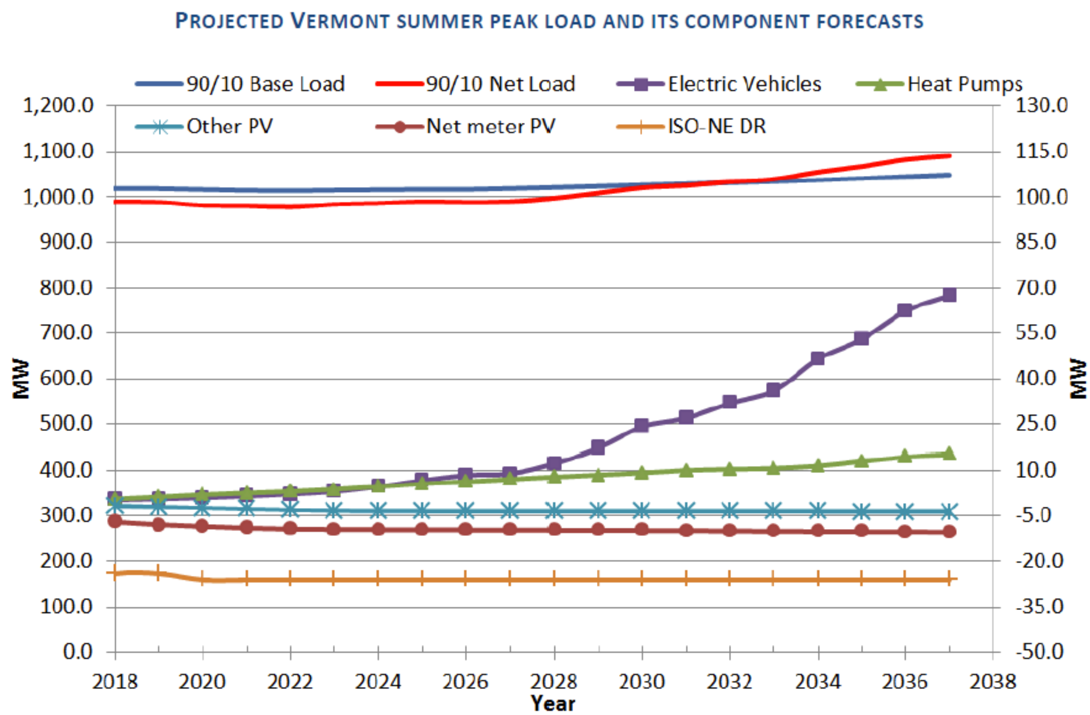
The New England Independent System Operator (ISO) is "responsible for the reliable and economical operation of New England's electric power system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system."[20] Hyde Park can use the information with the ISO's Regional System Plan for its own planning purposes.

D.3.1 Emerging Technologies

VELCO creates a long-range transmission plan, which within the analysis is a discussion of how emerging technologies can affect the future load of the state. VELCO balances the impacts for efficiency and standard offer against electric vehicles and fuel switching. VELCO's 2018 Plan states Predicting future demand relies on assumptions about economic growth, technology, regulation, weather, and many other factors. In addition, forecasting demand requires projecting the demand-reducing effects of investments in energy efficiency and small-scale renewable energy."[21] In **Figure 35**, VELCO assesses the MW impacts each technology can do to the state's load. Analyzing the trends, it can be reasonably assumed Hyde Park's load will increase or decrease at the same rate, if within Hyde Park, any technology enhancements include these same components.

[20] 2015 Regional System Plan (https://www.iso-ne.com/system-planning/system-plans-studies/rsp)
[21] https://www.velco.com/our-work/planning/long-range-plan/longrangeplan2018

Figure 35: VT Load Forecast[22]



D.3.1.1 Distributed Generation (DG)

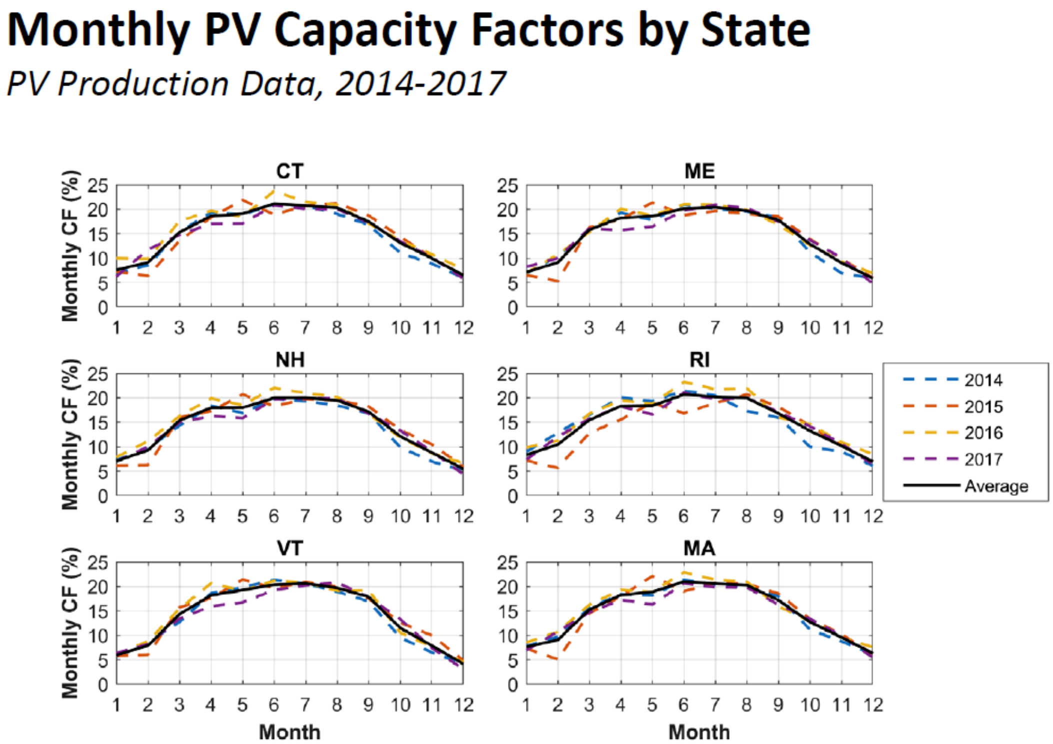
The ISO New England website describes DG as "Generation provided by relatively small installations directly connected to distribution facilities or retail customer facilities. A small (24 kilowatt) solar photovoltaic (PV) system installed by a retail customer is an example of distributed generation."[23] The ISO reached out for PV data within the Vermont utilities to help determine the DG affect and Burlington, GMP, Stowe, VEC, VPPSA, and WEC provided data as of December 31, 2017.[24] Vermont's data totaled 257.24 MW. In Figure 36 below are the survey results from all the New England States PV data along with the Vermont data.

[22] *2018 Vermont Long-Range Transmission Plan*

[23] https://www.iso-ne.com/participate/support/glossary-acronyms#d

[24] https://www.iso-ne.com/static-assets/documents/2018/04/final-2018-pv-forecast.pdf

Figure 36: ISO-NE Total PV Installed Capacity Survey Results 2014-2017



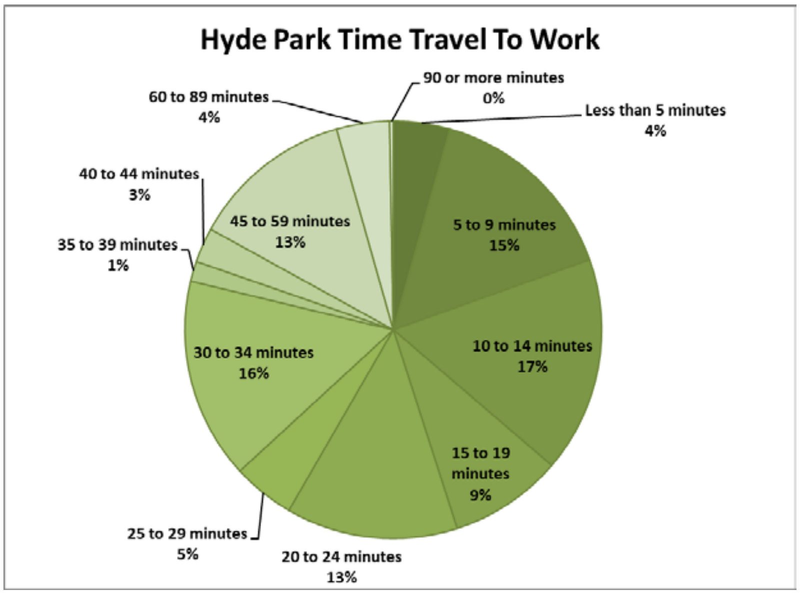
As of December 31, 2017, Hyde Park has 31 installed net-metered solar projects and one wind project on residential accounts. The total installed kW is 361.387 of solar and 2.47 of wind. Hyde Park's internal PV net-metered customers and the Standard Offer resources, which are DG amongst the VT utilities, both reduce Hyde Park's load.

With the Standard Offer Program as of April 17, 2019, there has been 76.997 MW's of PV projects accepted as well as 13.072 MW's of Biomass, Farm, Food Waste and Landfill Methane, and Hydroelectric. Lastly there are 2.364 of Wind generation reducing the Vermont Utility load by each municipal's pro rata share each hour. Hyde Park's share percentage beginning in 1/1/2019 was .2251%. Going forward, DG within both Vermont and within Hyde Park will help count towards Hyde Park's RES compliance obligation.

D.3.1.2 Electric Vehicle Penetration

A majority of Hyde Park's residents (86%) travel to work by mode of a car, with 4% of the population carpooling to work[25]. Time traveled for the majority of residents is greater than 25 minutes to work (29%), which could lead one to believe that, in theory and without constraints, Hyde Park's residents could use the current plugin electric vehicle (EV) or plugin hybrid electric vehicle (PHEV) technology in order to reduce gas usage due to longer commutes to work.

Figure 37: Hyde Park's Time Traveled to Work



Kelley Blue Book lists the many different electric car options[26], such as a Tesla Model 3, a Ford Fusion Energi, a Honda Clarity Plug-in hybrid, a Nissan LEAF, and a Toyota Prius Prime. These each offer enough daily gasoline-fee free driving range to meet the needs of the majority of consumers on electric power alone, and/or in the case of the plug-in hybrids, for the majority of annual miles traveled.

The Tesla Model 3 travels up to 310 miles on a single charge. With a car like this, one can recharge for 15 minutes at a supercharger for another 180 miles. The 2019 Clarity (Plug-in Hybrid) gets 47 miles of battery power and total range of 340 miles combined if the hybrid system is also used. With a car like this, one would have to expect a full recharge to take 2.5 hours with a 240-volt charger or up to 12 hours

[25] http://www.city-data.com/housing/houses-Hyde-Park-Vermont.html
[26] https://www.kbb.com/electric-car/

with a standard 120-volt plug. This vehicle charges at a rate of up to 6.6 kW; the Clarity uses up to 15 kWh per charge, including charging losses.

Assumptions for this IRP include 1) the average speed of the Hyde Park driver is 35 MPH, 2) there are an average of 250 work travel days a year, and 3) the use of a discharge rate of three miles per kWh, for a conservative average approach.

"Electric car's energy consumption is measured in kilowatt-hours per 100 miles (kWh/100 miles) . . . If an EV requires 40 kWh to recharge a fully depleted battery, and the rate is 18 cents per kWh, that's $7.20 for a fill-up." For a 2019 Nissan Leaf, its average rated efficiency of 150 MPGe translates to 40 kilowatt-hours per 100 miles. Just multiply that by your electric cost."[27] Table 11 below shows the impact of potential EV penetration. With 100% penetration, Hyde Park's average annual load may increase by 2,039 MWhs; whereas a low case of 25% penetration might add 509 MWhs. Currently, Hyde Park does not have any EV charging stations.

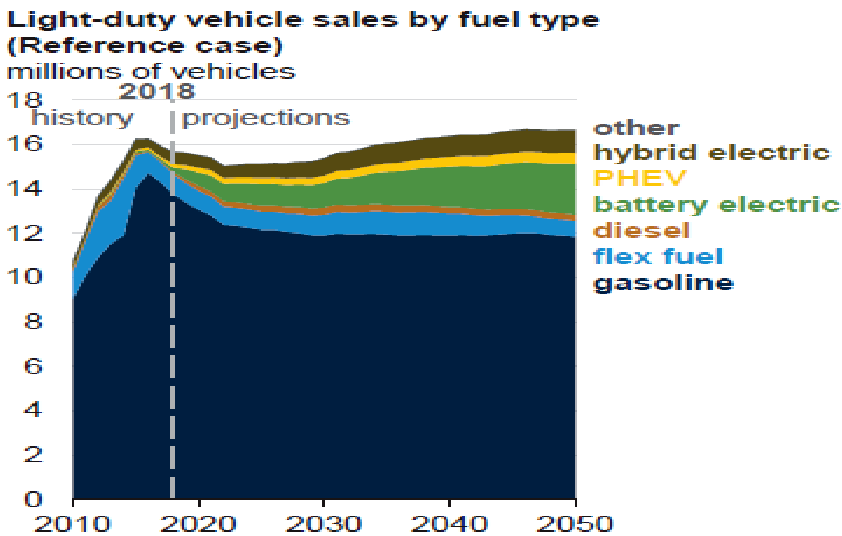
Table 11: Impact of Potential EV penetration in Hyde Park's work force

Time Traveled to Work	#	%	Miles using AVG 35 MPH	kWh round trip	kWh used for the year	EV Usage 100%	EV Usage 50%	EV Usage 25%	
Less than 5 minutes	31	4%	2.9	1.94	15,060	15,060	7,530	3,765	
5 to 9 minutes	107	15%	5.2	3.50	93,564	93,564	46,782	23,391	
10 to 14 minutes	118	17%	8.2	5.44	160,507	160,507	80,253	40,127	
15 to 19 minutes	62	9%	14.0	9.33	144,573	144,573	72,286	36,143	
20 to 24 minutes	94	13%	16.9	11.27	264,856	264,856	132,428	66,214	
25 to 29 minutes	34	5%	16.9	11.27	95,799	95,799	47,899	23,950	
30 to 34 minutes	110	16%	19.8	13.21	363,375	363,375	181,688	90,844	
35 to 39 minutes	11	2%	22.7	15.16	41,681	41,681	20,841	10,420	
40 to 44 minutes	19	3%	25.7	17.10	81,225	81,225	40,613	20,306	
45 to 59 minutes	89	13%	34.4	22.93	510,182	510,182	255,091	127,546	
60 to 89 minutes	29	4%	51.9	34.59	250,768	250,768	125,384	62,692	
90 or more minutes	2	0%	52.5	34.98	17,489	17,489	8,744	4,372	
	706			180.72	2,039,078	2,039,078	1,019,539	509,769	kWh/yr
						0.23	0.12	0.06	MW/hr

The US Energy Information Administration (EIA) estimates car usage, of both conventional and alternative fuels, in a forecast that extends through the year 2050.[28] When necessary, Hyde Park will determine how to promote and accommodate electric vehicles. EV will become a high interest for Hyde Park, because EV stations and usage will count towards compliance of the Tier III Renewable Energy Standard.

[27] https://www.edmunds.com/fuel-economy/the-true-cost-of-powering-an-electric-car.html
[28] https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf

Figure 38: Annual Energy Outlook 2019 vehicle sales by fuel type



D.3.1.3 Energy storage

Storage technology for electrical energy is growing in popularity. This technology offers users the ability to meet demand whenever needed and, more importantly, enables user to call upon it during peak energy events. HPE could use this energy to reduce their load during these events and help reduce peak load. Energy storage could not only save HPE on load cost, but it could also reduce their transmission and capacity charges within the ISO. **Table 12** below shows how a system using a .25 MW storage capability at the critical peak times can result in large yearly savings. See section D.2, Market Conditions, for the forecasted rates used to calculate a .25 MW reduction. ENE also forecasted the capacity reduction using an estimated 40% reserve adder. With these assumptions, HPE would not only reduce its peak by the .25 MW, it would ultimately reduce it by the storage amount plus the ISO reserve adder, making storage a more appealing tool for cost savings.

Table 12: Capacity and Transmission Savings

Project Assumptions	
MW	0.25
Commerical Operation Date	1/1/2019
Load Zone	VT
Est Reserve Margin	40%
RNS Ratio (10/12 months etc)	83%

Row Labels	Total ISO Capacity Savings	ISO RNS Savings	Total Savings
2019	$ -	$ 21,800	$ 21,800
2020	$ 12,907	$ 25,004	$ 37,910
2021	$ 20,522	$ 26,249	$ 46,770
2022	$ 17,383	$ 27,494	$ 44,877
2023	$ 15,960	$ 28,773	$ 44,733
2024	$ 15,960	$ 30,111	$ 46,071
2025	$ 15,960	$ 31,511	$ 47,471
2026	$ 15,960	$ 32,977	$ 48,937
2027	$ 15,960	$ 34,511	$ 50,471
2028	$ 15,960	$ 35,162	$ 51,122
2029	$ 15,960	$ 35,162	$ 51,122
2030	$ 15,960	$ 35,162	$ 51,122
2031	$ 15,960	$ 35,162	$ 51,122
2032	$ 15,960	$ 35,162	$ 51,122
2033	$ 15,960	$ 35,162	$ 51,122
Grand Total	**$ 226,372**	**$ 469,400**	**$ 695,771**

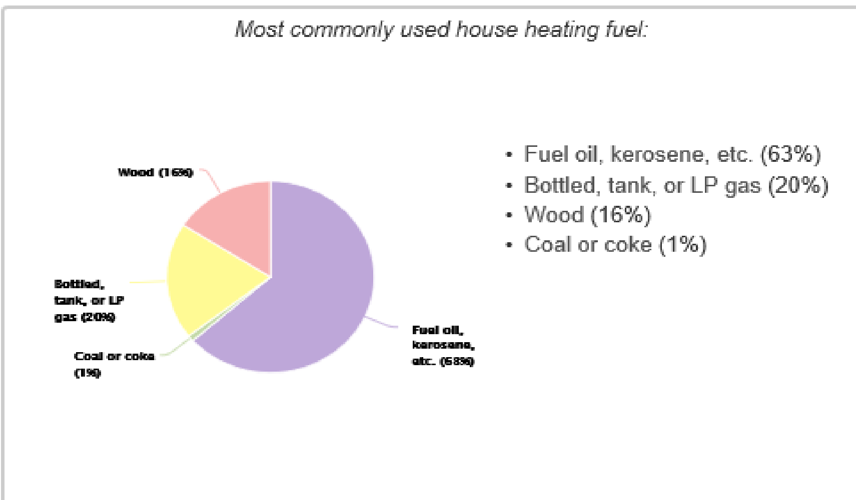
The greatest benefit of energy storage is its ability to heighten the capacity factor of renewable generation, such as solar. "These devices can also help make renewable energy, whose power output cannot be controlled by grid operators, smooth and dispatchable." [29] When solar production is low and a peak event is on the horizon, energy storage can supplement the solar output, and thereby, enable load reduction during the critical time.

[29] https://www.energy.gov/oe/services/technology-development/energy-storage

D.3.1.4 Fuel Switching

Even if power generators desire to fuel switch, sometimes it is just not available. “Unfortunately, owners of coal-fired power plants cannot easily switch fuels. A coal boiler is designed to burn coal, not natural gas. Even if a coal plant was modified to accept natural gas, the resultant fuel efficiency would be horrible and production costs would remain elevated.”[30] Costs would be large for buildings that use oil as a heating source, if they wanted to fuel switch as well. They cannot just switch to natural gas if there are no pipelines to connect to the homes or businesses, etc. Referencing city-data.com’s reporting as of March 29, 2017, complied data shows the max fuel source for Hyde Park is oil, kerosene at 63%. If consumers switch to electric heating and cooling options due to economics this has the potential to increase Hyde Park’s load. Other options would be to switch to wood/pellets. “Central wood pellet heating systems offer all the comfort and hands-off convenience that people have come to expect from traditional heating systems, but are fueled by local, sustainable wood pellets instead of fossil fuel”[31] Although fuel switching among power generators is becoming more and more noticeable, due to either economics or Federal policies, individual home and business fuel switching is less common. With more rebates and incentives and more efficient systems are offered this should change and become more popular.

Figure 39: Hyde Park’s Commonly Used Heating Fuel



[30] http://breakingenergy.com/2012/10/15/fuel-switching-is-not-so-easy/

[31] https://www.efficiencyvermont.com/tips-tools/guides/a-consumer-s-guide-to-central-wood-pellet-heating-systems

D.3.2 Environmental attributes

Environmental attributes are defined as "characteristics of a program or project (such as particulate emissions, thermal discharge, waste discharge) that determine the type and extent of its short-term and long-term impacts on its environment".[32] Projects qualify their attributes in different state classifications, based on year, fuel type, and emissions to name a few. These attributes are then marketable on a current platform called NEPOOL Generation Information System. Projects with qualifying attributes trade them to participants within the New England ISO, who apply them towards their renewable portfolio to meet compliance rules

Beginning in 2017, Vermont has incorporated a renewable energy standard program, or RES, that requires utilities to meet various obligations of renewable attributes. The State goal is to "obtain 90% of its energy from renewable sources by 2050."[33] Additional RES information is found in the Renewable Energy Standard (RES) section G below.

D.3.3 Assessment of Carbon Impacts

Energy New England began the carbon assessment by reviewing the historical carbon intensity of HPE's power mix from 2010 through 2018 and comparing it to the forecasts for the given years. ENE quantified HPE's yearly non-emitting MWH totals by counting its NYPA allocations and REC retention and compared this total against their total yearly retail sales data. ENE collected ISO-NE's final emission reports to incorporate the carbon impact of the regional system for each year.[34] Even though there are other components of GHG such as CH_4 and N_2O, ENE chose to focus on CO_2 because "in the U.S., CO_2 emissions represent more than 99 percent of the total CO_2-equivalent GHG emissions from all commercial, industrial, and electricity generation combustion sourcesCO_2 emission rates."[35]

D.3.3.1 *Emission Calculation*

ENE chose to calculate HPE's emission rates using ISO-NE's yearly ISO New England Electric Generator Air Emissions Report. Although the report is published on a lag, the methodology used to create the emission rate best suits HPE's portfolio emission estimates. The ISO uses a total system emission rate calculation method that is based on the emissions by all the ISO New England generators during a calendar years' worth of production. They use actual run time for on and off-peak generation at the emission rate for each month. The emission rate uses 76% of the reported CO_2 from actual US EPA's Clean Air Market Division (CAMD) database, as well as the Regional Greenhouse Gas Initiative (RGGI).

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[32] http://www.businessdictionary.com/definition/environmental-attributes.html
[33] http://publicservice.vermont.gov/renewable_energy
[34] https://www.iso-ne.com/about/key-stats/air-emissions
[35] https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

They also use EPA's eGRID annual emission rates as a means of accounting for units for which this information is not available.

All units that are dispatched are included in the emission rate calculation. The calculation is:

$$\text{Annual System Emission Rate (lb/MWh)} = \frac{\text{Total Annual Emissions (lb) all generators}}{\text{Total Annual Energy (MWh) all generators}}$$

Using ISO data is important because not all generation is operational at the same or all of the time. The ISO tracks the air emissions from the NE system Grid while taking into consideration:

- Forced and scheduled maintenance outages
- Fuel and emission allowance costs
- Imports and exports to and from NE region
- System energy consumption
- Water availability, etc.

Incorporating these factors set ISO emissions methods apart from those of other data sources such as eGRID. EPA's eGRID states "Emissions and emission rates in eGRID represent emissions and rates at the point(s) of generation . . . they do not take into account any power purchases, imports, or exports of electricity into a specific state or any other grouping of plants, and they do not account for any transmission and distribution losses between the points of generation and the points of consumption. Also, eGRID does not account for any pre-combustion emissions associated with the extraction, processing, and transportation of fuels and other materials used at the plants or any emissions associated with the construction of the plants."[36]

D.3.3.2 Emission Trends

Total generation is down by 17.8% from 2008 to 2017. We use 2017 as it is the most recent period for which the ISO regional emissions report is available. Coal has decreased the most over the period, dropping from 15% to 2%. Oil generation was cut in half from 2% to 1%. This has resulted from a combination of tightening emission requirements, relatively higher operating and maintenance expenses of solid fuel and older thermal generating facilities compared to natural gas ones, and market forces, namely low natural gas prices over the past several years. The latter is due to the merchant generator boom that occurred in the late 1990's and early 2000's, resulting in the building out of thousands of megawatts of high efficiency, natural gas fired generating capacity. This moved natural gas to become the dominant marginal fuel in New England, where it now sets the marginal wholesale

[36] https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_technicalsupportdocument_v2.pdf

electricity price 60% of the time or more. This means that all generating technologies' fortunes are affected by the price and availability of natural gas.

Figure 40 shows the fuel mix in the ISO New England control area in 2008 compared to 2017. We use 2017, as it is the most recent period for which the ISO regional emissions report is available. Total generation is down by 17.8% from 2008 to 2017. We use 2017 as it is the most recent period for which the ISO regional emissions report is available. Coal has decreased the most over the period, dropping from 15% to 2%. Oil generation was cut in half from 2% to 1%. This has resulted from a combination of tightening emission requirements, relatively higher operating and maintenance expenses of solid fuel and older thermal generating facilities compared to natural gas ones, and market forces, namely low natural gas prices over the past several years. The latter is due to the merchant generator boom that occurred in the late 1990's and early 2000's, resulting in the building out of thousands of megawatts of high efficiency, natural gas fired generating capacity. This moved natural gas to become the dominant marginal fuel in New England, where it now sets the marginal wholesale electricity price 60% of the time or more. This means that all generating technologies' fortunes are affected by the price and availability of natural gas.

Figure 40 ISO-NE System Energy Generation Percentage by Fuel Source[37]

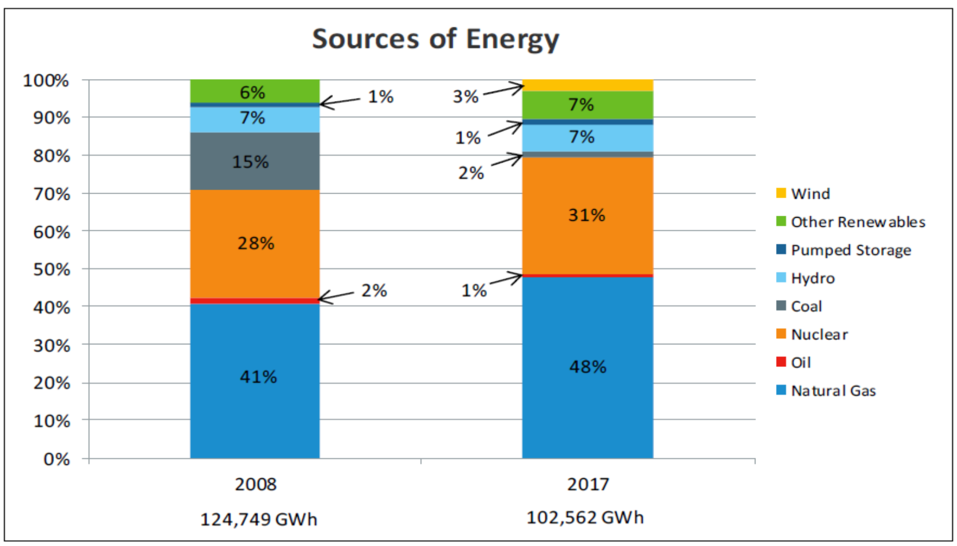


Table 13 shows New England's average yearly CO_2 emission rates. Following the build out of merchant, gas fired generating capacity in the late 1990's and early 2000's, these rates continue to trend

[37] https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf

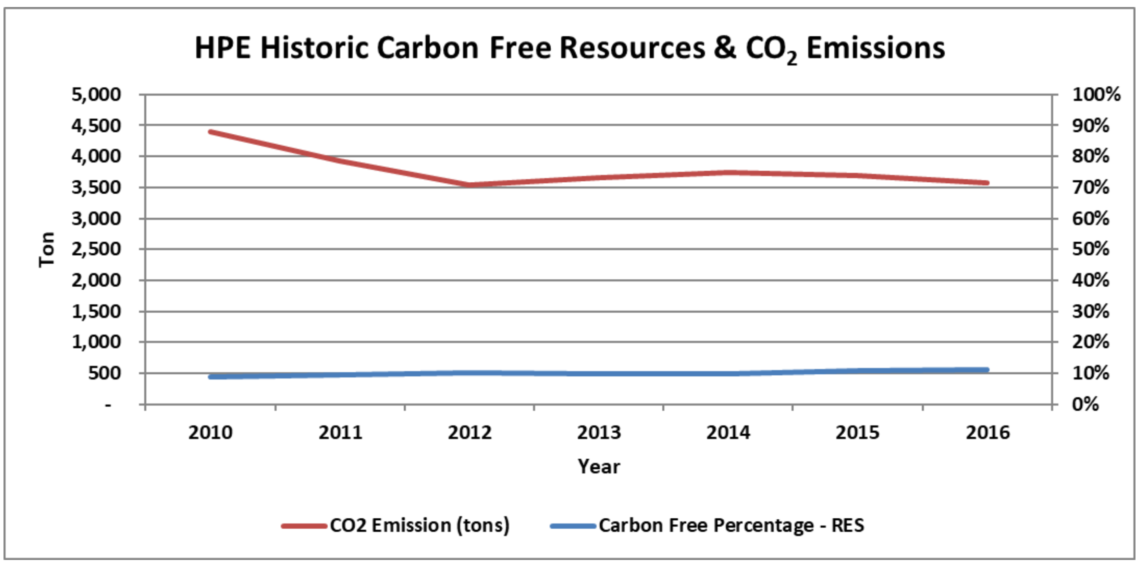
downward slightly as the underlying resource mix changes with less reliance on coal and oil generation. These rates were used to determine HPE's supply emission profile for its open position and bilateral commodity energy contracts since these purchases are not tagged to a particular generator.

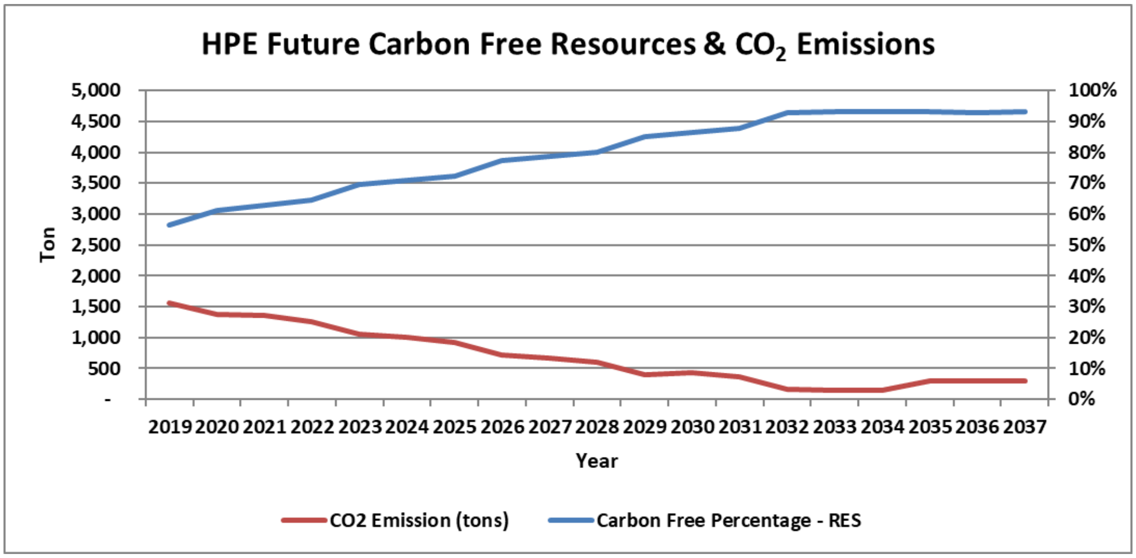
Table 13: Regional Annual CO_2 Emissions in lb/MWH

Annual System (NE)	2010	2011	2012	2013	2014	2015	2016	2017
Co2 Emission lb/MWH	829	780	719	730	726	747	710	682

HPE's current carbon reduction power supply portfolio includes New York Power Authority, and all retained RECs, as well as Seabrook. Below in Figure 41 shows that HPE's Historical portfolio represents about 4,300 s-tons of CO_2 in 2010 and drops to about 3,500 s-tons of CO_2 in 2016. The HPE's current emissions in 2017 was 1,693 s-tons of CO_2 due to the implantation of RES and decreases to roughly 427 s-tons of CO_2 in year 2030 as HPE's carbon free percentage increases to 86% based on the compliance of RES.

Figure 41   HPE CO2 Emissions and Carbon Free Portfolio





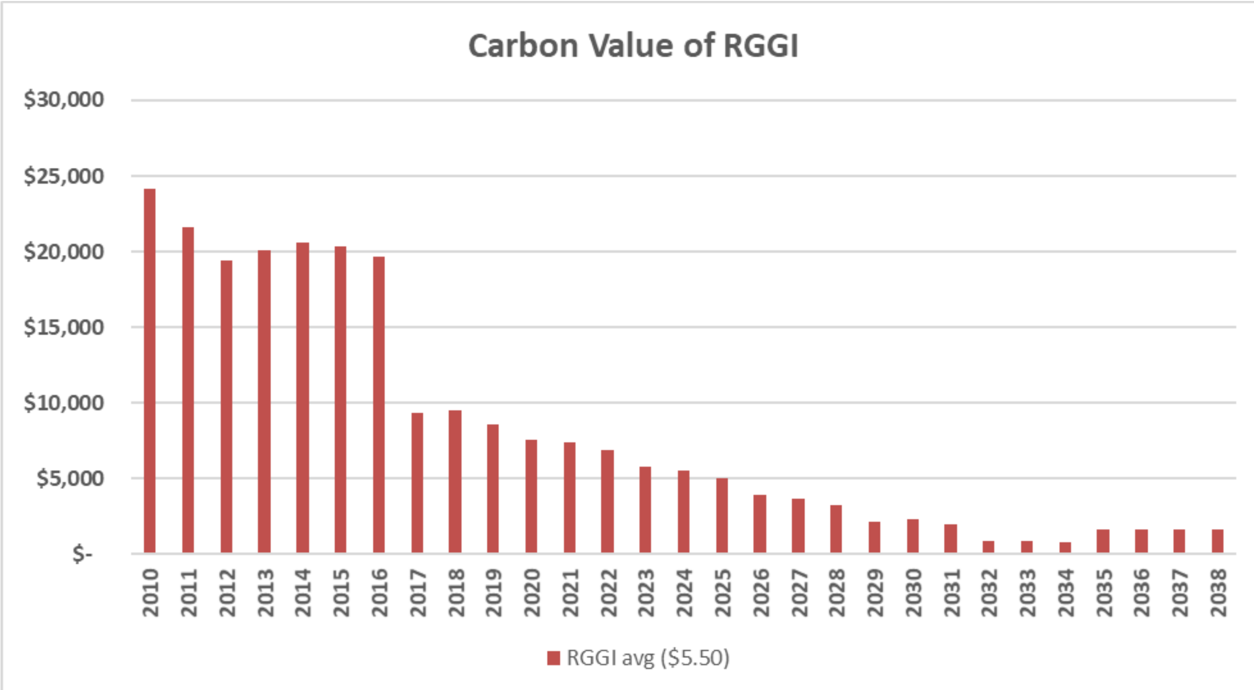
With the implementation of Renewable Energy Standards in 2017 HPE will be increasing their non-emitting portfolio by retaining and retiring RECs. In the evaluation, ENE projected the emission rates for 2018 through 2038. By applying the average percent change from the past five years (2013-2017), which was a decrease of 1.0% from the 2017 rate and held it constant throughout the IRP timeline. ENE also assumed HPE would be 100% compliant with Tier I, II, and III. Achieving the RES targets reduces HPE's carbon emissions by 45% from 2016 levels in 2017. By 2032 the final year of RES, HPE will have reduced CO_2 by 82% from 2016 levels. This decrease directly follows the State goals set in August 2015 at the New England Governors and Eastern Canadian Premiers to set targets of decreasing carbon in the region by 35% to 45% from 1990 levels by 2030.[38] In 2025, HPE's CO_2 emissions reduction totals 72%. This exceeds the target established by the Vermont Comprehensive Energy Plan of meeting 25% of energy needs using renewable sources by 2025.[39]

Carbon pricing is a way to value the carbon pollutant. The Regional Greenhouse Gas Initiative (RGGI) is a market-based program for reducing greenhouse gases. There is a rate associated to the carbon allowance emitted in short tons of CO_2. that generators purchase RGGI credits in order to emit CO_2. RGGI rates average around $5.50. In Figure 42 below is the carbon cost if Hyde Park were to buy RGGI credits for each ton of carbon at an average rate of $5.50.

[38] http://climatechange.vermont.gov/climate-pollution-goals

[39] https://outside.vermont.gov/sov/webservices/Shared%20Documents/2016CEP_Final.pdf

Figure 42 Carbon Value



E Data Models and Information

E.1 RES and Portfolio Optimization Model - @Risk®

In performing the RES portfolio integration and identifying an optimal REC position, Energy New England performed Monte Carlo simulations using the @RISK® commercial statistical software package to run optimization algorithms that identify the percentile of each outcome to HPE's portfolio.

The Energy New England Portfolio Simulation Model is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables. This method allows a view into the probability distribution of outputs. The reason for the quantitative modeling is to determine the sensitivity of Hyde Park's portfolio cost to the change in market conditions and to identify an optimal combination of resources that will provide Hyde Park with the highest probability of having a competitive and low-cost resource portfolio. The model allows the use of inputs that will represent extreme cases as well as mild cases per resource. ENE reviewed and analyzed these extreme cases in the stress testing results.

ENE used this model for the Energy Portfolio, Capacity Market and the RES modeling sections within the IRP. The RES base case model results can be found in G.2 RES modeling. The Capacity results can be found in G.4 Capacity modeling.

E.2 Forward Commodity Price Model- Lacima®

Lacima is a specialist provider of risk management, valuation and optimization software and services for multi commodity trading organizations.

Lacima enhances analytical capabilities around risk analysis by providing a platform from which to run 1,000's of scenarios, as compared to traditional empirical modeling, which limits the number of variables that can be efficiently modified. From Lacima's simulations, probability ranges are drawn from the output data.

Lacima uses Risk Factors as a basic unit to represent a data set. The stored historic data is used to estimate stochastic parameters which drive the "random" evolution of the risk factor through time. These risk factors use a forward expectation as a starting point from which simulations begin, and to which all simulations also have some tendency to revert over time. The forward expectation was forward Quotes, a Forecast Curve, and a historic average of Algonquin, Henry Hub, Mass Hub, and VT Zone. The process aggregates the results by time buckets and summarizes them across simulations into percentiles. For example, if 1,000 simulations are performed, but only the 5th percentile, the Mean, and the 95th percentile are to be reported, the report will contain three values for each output (one for each percentile), instead of 1,000 outputs.

F Assessment of Resources

F.1 Existing Energy Resources

Hyde Park's portfolio consists of several existing resources, including long-term contracts and entitlements, which provide supplier, fuel source, and term diversity. See Table 14 for a brief description of each resource. Each resource includes capacity information, annual production, fuel, location, and termination date.

Table 14: Hyde Park's Resources

2018 Total KWh's by Resource								
Resource	**MW**	**Type**	**MWH**	**KWH**	**Percent**	**Fuel**	**Location**	**End Date**
NYPA - Niagara	0.18	Block	1,209.40	1,209,403	9.3%	Hydro	Roseton	9/1/2025
NYPA - St. Lawrence	0.00	Block	28.29	28,292	0.2%	Hydro	Roseton	4/30/2032
Waterhouse Solar Project	-	Load Reducer	1,328.15	1,328,148	10.2%	Solar	Behind meter	Life of Unit
VEPPI	0.10	PURPA	485.66	485,656	3.7%	Hydro/Wood	VT Nodes	Exp. Varies
VEPPI-SPEED	-	Load Reducer	224.03	224,034	1.7%	Mix	Behind meter	Exp. Varies
HQ PPA Contract	0.10	ISO Bilateral	606.72	606,719	4.7%	Hydro	HQ Highgate 120	2038
Bilateral Purchase - Seabrook	0.10	ISO Bilateral	-	-	0.0%	Nuclear	Seabrook 555	2034
Market Contract		ISO Bilateral	1,378.85	1,378,850	10.6%			
ISO Energy Net Interchange			7,774.48	7,774,477	59.6%			
Totals			**13,035.58**	**13,035,579**	**100.0%**			

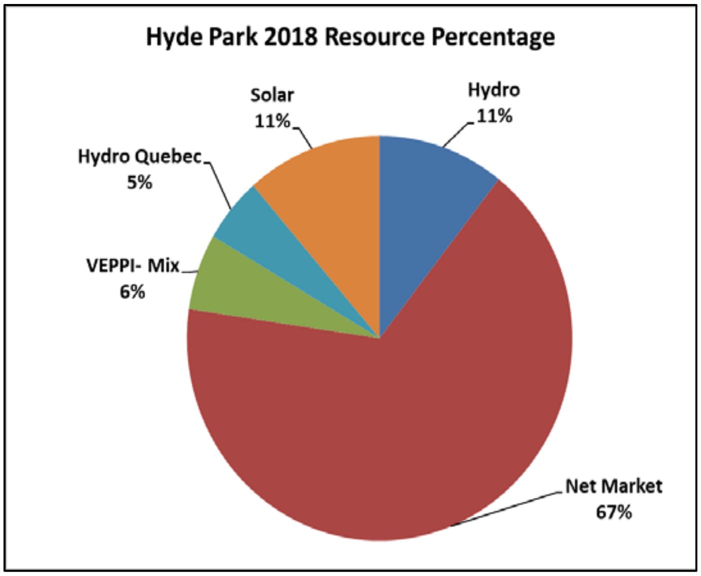
Below in Table 15 is Hyde Parks Resource Energy Cost. Included in the $80.18/MWH of the ISO Energy Net Interchange does include HPE's capacity cost. The $80.18/MWH is the sum of the total ISO-NE energy and capacity charges divided by the net purchases form the ISO-NE in 2018 of 7,774 MWHs. The energy position in 2018 would be calculated at $53.84/MWH. The remaining cost is due to the high capacity costs during the FCA 8 and FCA 9 periods.

Table 15: Hyde Park 2018 Current Resources Energy Cost

2018 Resource Cost			
NYPA - Niagara	$	25.23	$/MWH
NYPA - St. Lawrence	$	33.17	$/MWH
VEPPI-Hydro	$	96.21	$/MWH
VEPPI-SPEED	$	229.14	$/MWH
HQ PPA Contract	$	52.24	$/MWH
Bilateral Purchase	$	31.14	$/MWH
Bilateral Purchase - Seabrook	$	3.57	$/KW-mo
ISO Energy Net Interchange	$	80.18	$/MWH

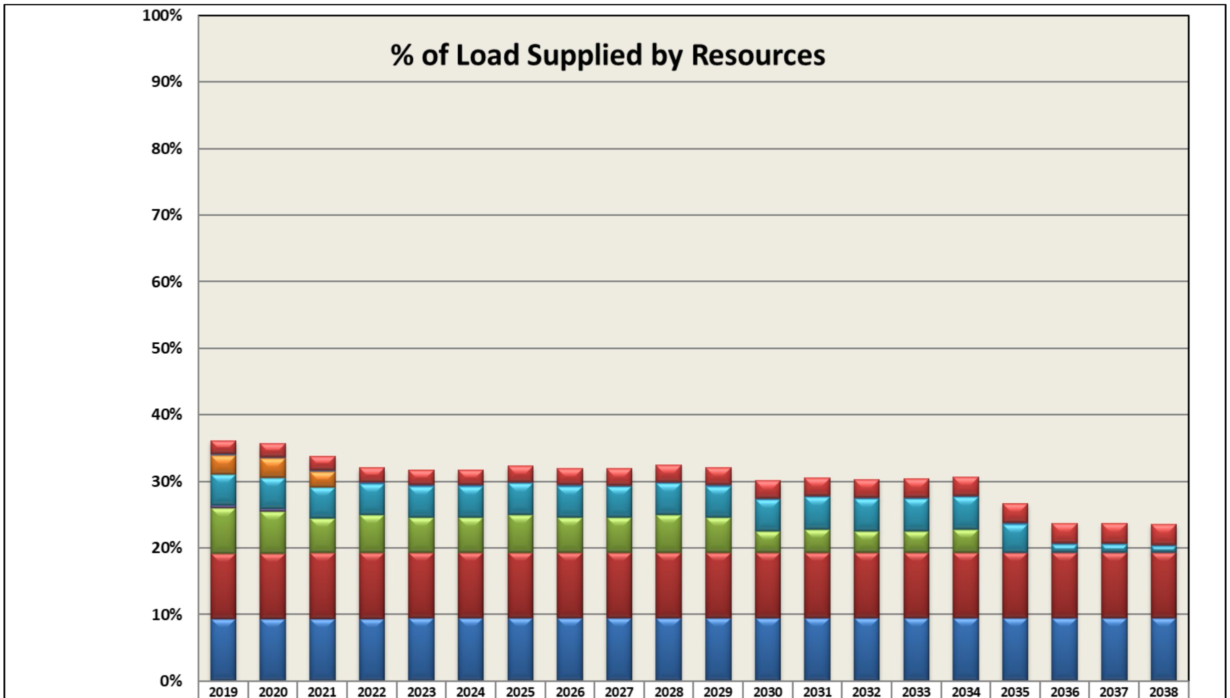
Figure 43 below, represents Hyde Park's 2018 resources by fuel type format. This pie chart shows that 67% of Hyde Park's coverage was from market purchases.

Figure 43: Energy Resources in 2018



In Hyde Park's resource forecast, found in Figure 44, ENE uses specific resource knowledge in order to estimate generation. Hydro Quebec is forecasted as stated in the purchase agreement with Vermont Public Power Supply and Hydro Quebec. NextEra Seabrook s forecasted as stated in the purchase agreement with Vermont Public Power Supply and NextEra. VEPPI and NYPA forecasts are each calculated using an average of historical generation, with VEPPI adjusted for expiring units. ENE used historical capacity factors for the solar forecast when estimating the solar projection for Hyde Park. This resource forecast results an exposure to the spot market for Hyde Park.

Figure 44: Hyde Park's yearly projected resource distribution



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
VEPPI SPEED BTM	2.1%	2.1%	2.2%	2.2%	2.3%	2.3%	2.4%	2.4%	2.5%	2.5%	2.6%	2.6%	2.7%	2.7%	2.8%	2.9%	2.9%	3.0%	3.0%	3.1%
VEPPI SPEED ISO	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Ryegate	2.9%	2.9%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro Quebec	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.9%	4.9%	4.9%	4.9%	4.2%	1.2%	1.2%	1.0%
VEPPI	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NextEra (Seabrook)	6.8%	6.3%	5.2%	5.7%	5.2%	5.2%	5.7%	5.2%	5.2%	5.7%	5.2%	3.2%	3.5%	3.2%	3.2%	3.5%	0.0%	0.0%	0.0%	0.0%
Solar Projects	9.8%	9.8%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%
NYPA	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%

F.1.1 New York Power Authority (NYPA)

The New York Power Authority provides preference hydroelectric power to New York's neighboring states. Two contracts provide this power to Vermont. The first is a one MW entitlement to the Saint Lawrence project in Massena, New York. The second is for a 14.3 MW entitlement in the Niagara project located in Niagara Falls, NY. The Saint Lawrence contract term runs through April 30, 2032 and the Niagara contract through September 1, 2025. The energy capacity and transmission payments required to deliver this entitlement to Vermont are at prices that are very competitive to the short and long term New England power market.

With the extension of Saint Lawrence, after December 23, 2017 VT utilities were no longer entitled to NYPA St. Lawrence RECs. This reduces the amount of coverage Hyde Park is able to declare for RES compliance through the NYPA contract.

F.1.2 Vermont Electric Power Producers, Inc. (VEPPI)

Hyde Park receives power from a group of independent power producer projects (IPPs) under Order 4.100 of the Vermont PUC. The power is generated by a number of small hydroelectric facilities. There were 19 VEPPI units, as of December 31, 2017, 14 have expired, leaving 5 remaining. VEPPI assigns the energy generated by these facilities using a load ratio basis that compares Hyde Park's electric sales to other utilities in Vermont on an annual basis. The VEPPI contracts have varying maturities, with the last VEPPI contract scheduled to end in 2020. Hyde Park's current pro rata share of the VEPPI production is .2084%, which started November 1, 2018 and will run through October 31, 2019. The prior percent which ran from November 1, 2017 through October 31, 2018was .0258%. The VEPPI contracts are priced with relatively high energy rates and modest fixed costs.

Note, the wood-fired Ryegate unit that was once within the VEPPI production expired on October 31, 2012. The utilities negotiated a 10-year contract for power. The contract now will terminate on November 1, 2022.

F.1.3 Sustainably Priced Energy Enterprise Development "SPEED" and Standard Offer

SPEED Standard Offer is a program established under Vermont Public Service Board Rule 4.300. The program's goal is to achieve renewable energy and long-term stable priced contacts. Vermont utilities will purchase power from the SPEED projects. These projects are behind the meter and each utility will have their percent share, (Hyde Park's share for November 1, 2017 through October 31, 2018 was .2247% and increased to .2275 for November 1, 2018 through December 31, 2018 than decreased to .2251% for January 1, 2019 through October 31, 2019) of load reduced by the output of the generation. Hyde Park receives a modest capacity credit, and renewable energy credits for these resources. The cost paid to the SPEED projects are set based on the generation type. The SPEED began in the fourth quarter of 2010.

Section 4.304 of Rule 4.300 defines Speed Projects (those that qualify to serve a Vermont utility's SPEED requirement) as:

> *"(SPEED projects are new electric generating projects that produce renewable energy. A "new" project means a project brought on-line after December 31, 2004. A SPEED project must use a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate. Obvious examples of SPEED projects are utility scale wind farms, hydroelectric projects less than 200 MW, wood-to-energy projects, landfill gas-to-energy projects, etc. Combined Heat and Power (CHP) projects are SPEED projects if they meet certain efficiency standards or if they are fueled with a renewable resource.*

Projects that use a mix of fossil fuels and renewable fuels, such as a diesel generator that is partially fueled with bio-diesel, may qualify as SPEED in proportion to the amount of renewable fuel (in this case bio-diesel) that is used.

The incremental energy produced by an expansion or modification of a pre-existing renewable energy project will be considered as a SPEED project."

In May of 2009, as the SPEED Program progressed and implemented modifications, it changed into the Standard Offer program. This change began a feed-in-tariff to encourage the development of SPEED resources by making contracts long term and at fixed prices to qualified renewable energy projects. By May of 2012, the Vermont Energy Act of 2012 expanded the program to 127.5 MW over a 10-year span with a new pricing mechanism for qualified projects. The 2017 RFP for the Standard Offer Program within the Public Utility Commission Docket No. 8817 contained avoided cost price caps. **Figure 45** shows the current fuel source breakdown of the Standard Offer Projects. The complete list of projects is in Appendix B.

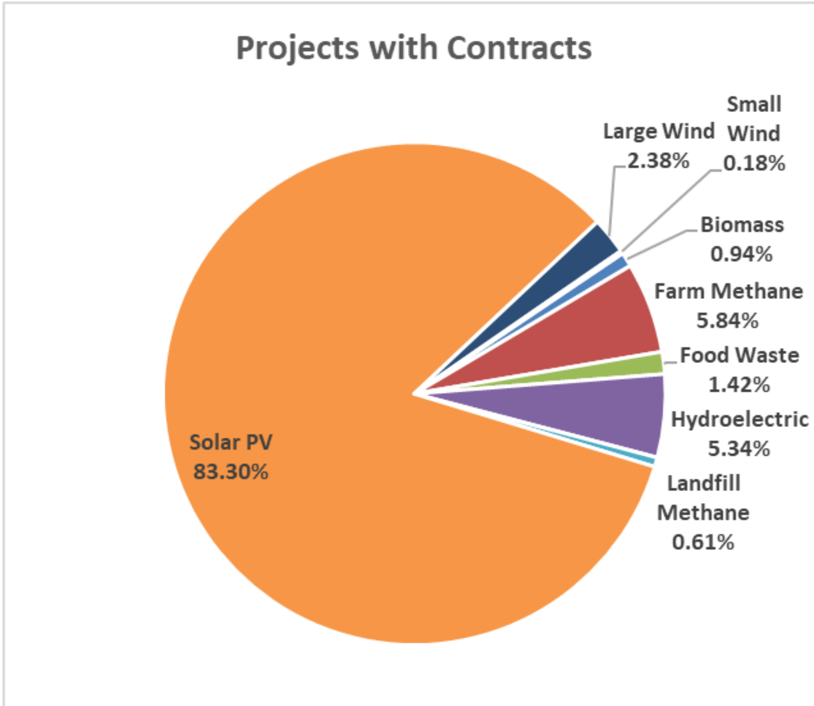
Table 16: 2017 Avoided Cost Price CAPS for Standard Offer

AVOIDED-COSTS PRICE CAPS

The following avoided-costs will serve as price caps for the 2017 RFP:

- Biomass - $0.125 per kWh (levelized over 20 years)
- Landfill Gas - $0.090 per kWh (levelized over 15 years)
- Wind > 100 kW - $0.107 per kWh (fixed for 20 years)
- Wind ≤ 100 kW - $0.2332 per kWh (fixed for 20 years)
- Hydroelectric - $0.130 per kWh (fixed for 20 years)
- Food Waste Anaerobic Digestion - $0.208 (fixed for 20 years)
- Solar - $0.130 per kWh (fixed for 25 years)

Figure 45: Energy Provided by Standard Offer Projects



F.1.4 NEW -Hydro Quebec Contract

This contract began on November 1, 2012, for energy and renewable credits. The contract pricing will be flexible and competitive to the market price because it will follow the defined Energy Market index and the cost of power on the forward market. The pricing is based partly on market prices, partly on inflation, and carries limits on year-to-year price fluctuations. Given the greater degree of market price volatility exhibited since the original Hydro Quebec contract was agreed, this pricing approach should be beneficial to Hyde Park as the contract will be limited to how "out of market" it might become for both Hydro Quebec and Hyde Park. This is an important contract quality in the current market environment, and it reduces potential rate pressure to Hyde Park. In addition to the price flexibility, this will continue to provide very low carbon energy to Hyde Park, helping it maintain a market price based green energy procurement strategy.

Table 17: Contract based on 255 MW

Contract Start Date	11/1/2012	11/1/2015	11/1/2016	11/1/2020	11/1/2030	11/1/2035
Final Deliver Date	10/31/2012	10/31/2016	10/31/2020	10/31/30	10/31/2035	10/31/2038
Hyde Park Entitlement (MW)	.007	.088	.104	.104	.107	.026

F.1.5 NextEra – Seabrook offtake

Beginning January 1, 2015 and going through December 31, 2034. Hyde Park will receive capacity as seen below in Table 18. The delivered capacity charge is a fixed rate per month with a 3.2% escalator.

Table 18 NextEra Capacity

Contract Start Date	6/1/2015	6/1/2021	6/1/2029
Final Deliver Date	5/31/2021	5/31/2029	12/31/2034
Hyde Park Entitlement (MW)	.100	.083	.050

The energy portion of the contract begins on January 1, 2019 and goes through December 31, 2034. Hyde Park will receive energy as seen below in Table 19. The delivered energy charge is a fixed rate per month with a 3.2% escalator.

Table 19 NextEra Energy

Contract Start Date	1/1/2019	1/1/2021	1/1/2029
Final Deliver Date	12/31/2020	12/31/2028	12/31/2034
Hyde Park Entitlement (MW)	.100	.083	.050

This contract also provides Hyde Park with the Emissions Free Energy Certificates ("EFECs") that will be 50% of the entitlement. These qualify for RES compliance.

F.1.6 Waterhouse Solar Farm

Hyde Park built a 1 MW AC ground mounted solar electric generation project. Estimated output is approximately 1,568 MWh per year. This is about 10% of Hyde Park's annual energy requirement. Another benefit to Hyde Park from this project is the ability to use the renewable energy credits towards Tier 2 and Tier 3 of the Renewable Energy Standard. Considered as distributed generation, or behind

Hyde Park's meter, additional benefits include energy, capacity, and transmission. The project began operation in September 2016.

Figure 46 Solar Project

G Renewable Energy Standard (RES)

In July 2015, using the 2011 Vermont Comprehensive Energy Plan, the State of Vermont established Act 56 (H. 40) in order to detail the State's goals and place direction on how utilities will reach these goals. The RES requires utilities to buy or retain renewable energy credits and energy transformation projects, and it set yearly percentage goals of retail sales to be covered by them. In lieu of renewable credits or transformation projects, a utility can meet its obligation by paying an alternative compliance payment at rates set by the State. The compliance rates adjust annually for inflation using CPI.

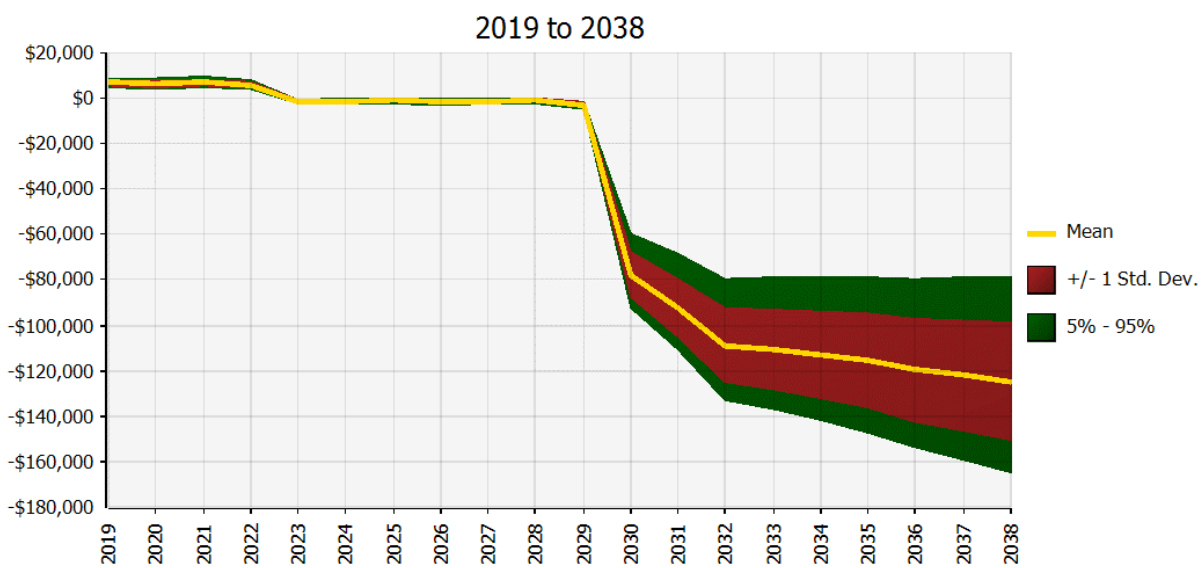
G.1 The Three Tiers to the RES program:

- Tier I: Meet a 75% by 2032 total renewable energy requirement (55% in 2017)
  - Any class of tradeable renewable attributes that are delivered in New England qualify
  - Approved Unit generations that will qualify towards compliance are Standard Offer, Hydro Quebec bilateral, Solar and NYPA.
- Tier II: Meet 10% of sales with distributed generation in 2032 (1% in 2017)
  - New Vermont based unit that is 5 MWs or less or renewable generation
- Tier III: Municipal utilities must meet $10^{2/3}$% of sales with "energy transformation projects" in 2032 (2% in 2019)

- Excess Tier II-qualifying distributed generation or project that reduces fossil fuel consumed by their customers and emission of greenhouse gases qualifies for compliance

Beginning in 2017, Vermont Statue Title 30, Chapter 89 (30 V.S.A. § 8002-8005) began the RES for the Vermont distribution utilities. There are three tiers that HPE will comply with either in renewable energy credits or compliance payments. Analyzing HPE's current portfolio, ENE estimated the cost impact to Hyde Park's retail sales forecast, as shown below in Figure 47. Compliance of RES heavily influenced the selection of portfolio scenarios for the IRP.

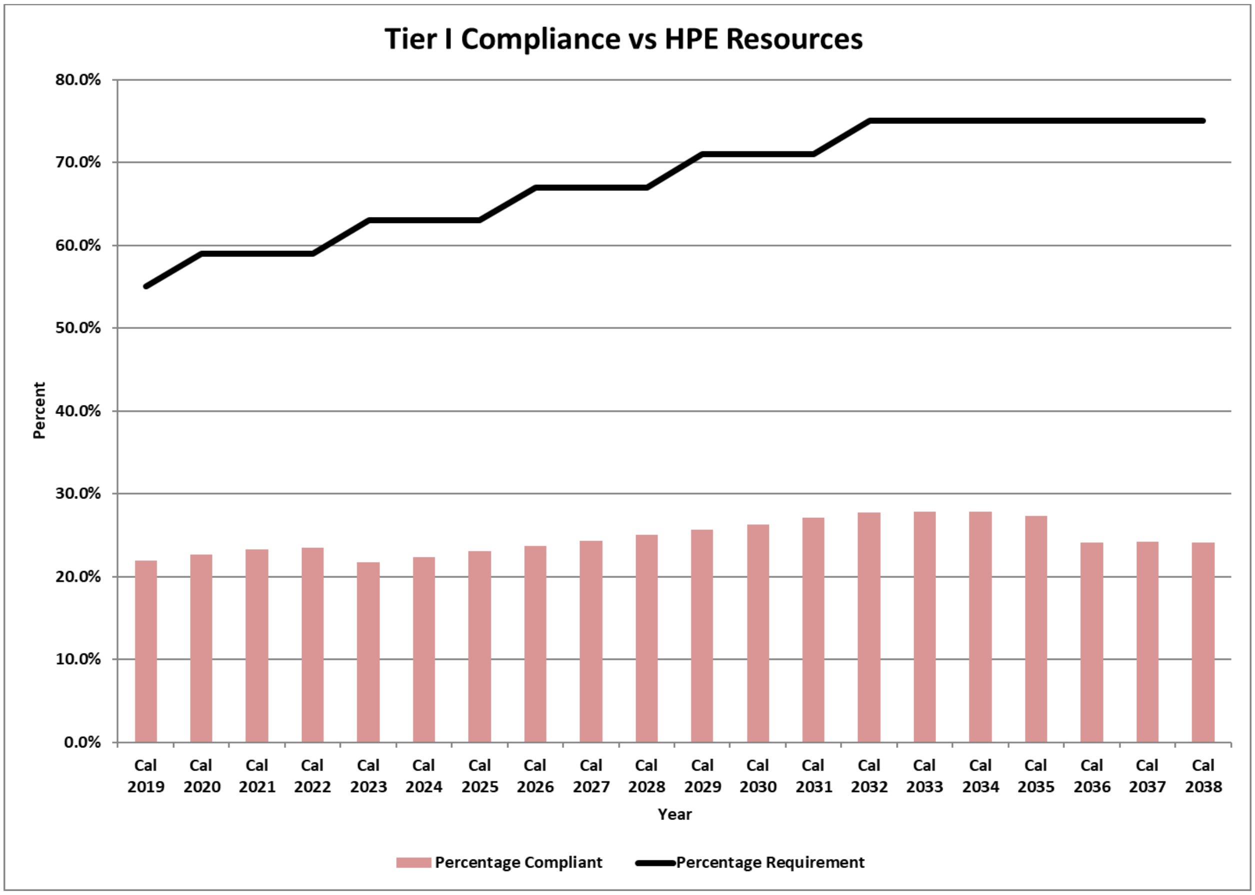
Figure 47 Hyde Park's Potential RES Credit (Cost) Cash Flow



G.1.1 Tier I

Currently Hyde Park's resource portfolio contains about 36% renewable generation. This percentage comes from qualified generation that is either State approved, such as HQ and the New York Power Authority contract for RES, or as generation, that has tradeable renewable energy credits. below in Figure 48 shows HPE's Tier I forecast. As the percentage requirement increases, the compliance gap increases. Using this forecast of current contracts, one can assess new projects. When looking forward to future purchases, Hyde Park can analyze the cost of retaining a project's renewable energy credits against possible future compliance payment rates.

Figure 48: Hyde Park's Tier I Forecast



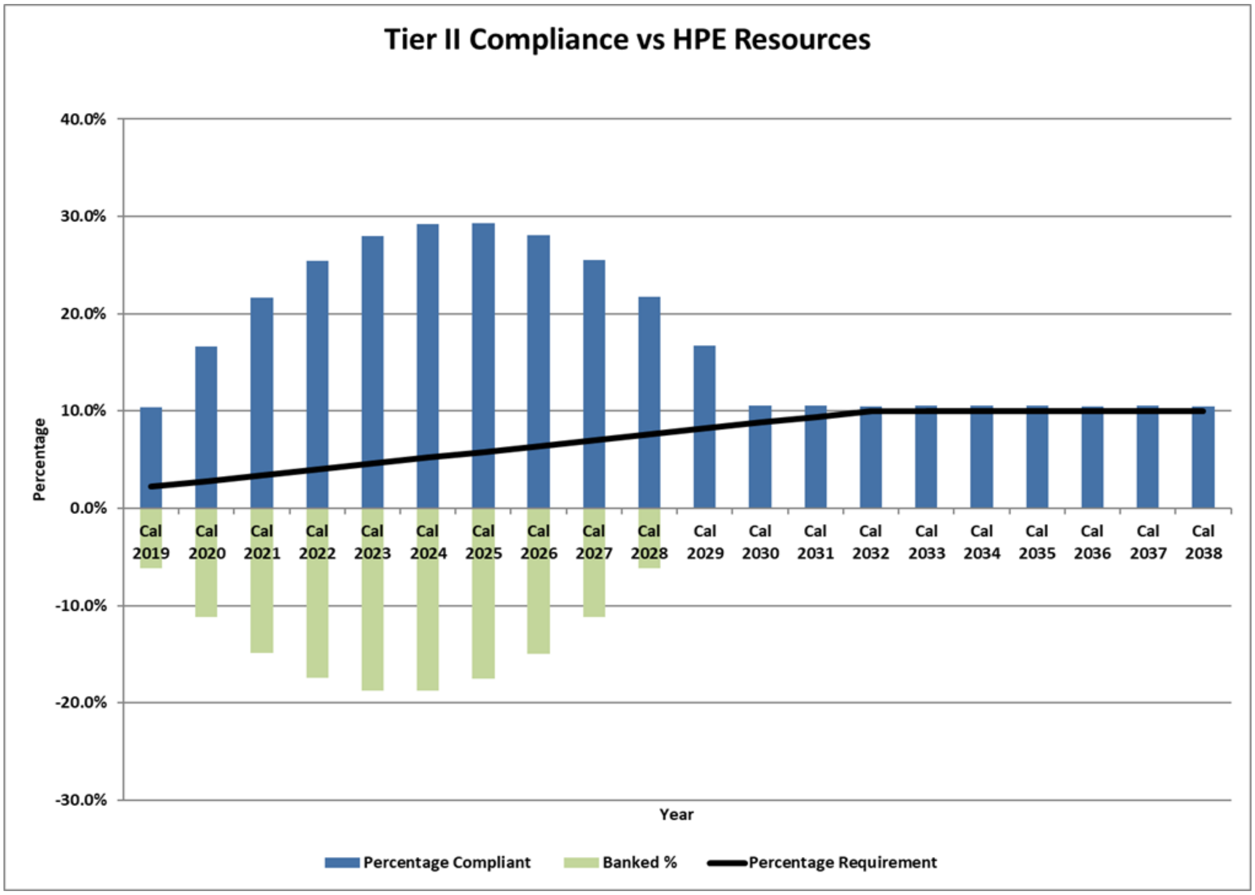
G.1.2 Tier II

Currently, Hyde Park's distributed generation resource portfolio is about 9.8% renewable generation, mostly made up by Hyde Park's Waterhouse Solar project, which is 1 MW of distributed generation behind HPE's transmission system. The renewable energy credits will qualify to Tier II compliance. "The Commission shall allow a provider that has met the required amount of renewable energy in a given year, commencing with 2017, to retain tradeable renewable energy credits created or purchased in excess of that amount for application to the provider's required amount of renewable energy in one of the following three years."[40] With this three-year banking policy, HPE is able to maintain Tier II compliance throughout the RES program. Below in

[40] 30 V.S.A. § 8004(c)

Figure 49 shows the coverage and excess of Tier II RECs. The excess RECs HPE will use for Tier III compliance.

Figure 49: Hyde Park's Tier II Forecast



G.1.3 Tier III

Tier III is for energy transformation projects. This category is set to encourage projects that will help reduce fossil fuel usage and reduce greenhouse gas emissions. Currently, Hyde Park is long Tier II RECs, and therefore are able to cover the majority of their Tier III obligation with those RECs. The Public Utility Commission approved a conversion methodology developed by the Department of Public Service that utilities will use to equate fossil fuel reduction into MWHs of electric energy. The conversion uses the most recent year's approximate heat rate for electricity net generation from the total fossil fuels category as reported by the U.S. Energy Information Administration in its Monthly Energy Review.[41]

In 2020, HPE plans to develop a RES Tier 3 program in participation with Efficiency Vermont that allows sharing of credits with a focus on incentives for EV + Charger and Cold Climate Heat Pumps. HPE is a participant in the State of Vermont EV Incentive Program.

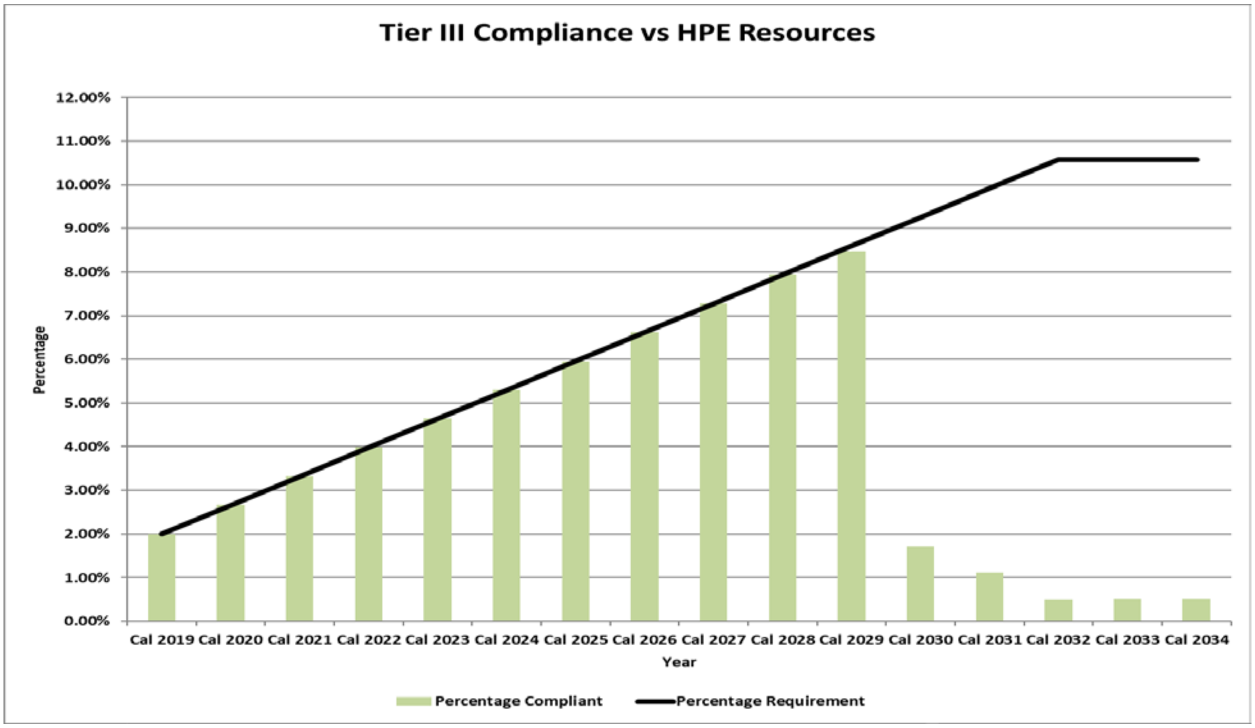
HPE's first long term strategic initiative is a voluntary program offering benefits to lower income households. The overall mission of the COMMUNITY FUND is to prudently meet state energy standards while creating a more sustainable and resilient community. Funds come from voluntary contributions ("Gifts") and/or ("Roundup") made by utility customers. These contributions may be recurring or single event and are offered on the utility bill. We hold these contributions in a separate fund account, establish annual guidelines, and awards incentives that allow lower income homeowners to weatherize and/or afford the initial cost of energy efficient electric heating and cooling technology that reduces fossil fuel consumption. An energy audit is required and, at this time, Funds given to a participant must match an Efficiency Vermont incentive. The Fund will utilize limits established by the Vermont Agency of Human Services, Department for Children and Families, Weatherization Program. Participants will self-certify income eligibility.

PUC Order in Docket 8550 states, "A DU shall endeavor to provide equitable opportunities to its customer sectors in rough proportion to each customer sector's annual retail sales." It is important to note that while Hyde Park Solar, Waterhouse Project fulfills Tier 3 requirements for many years, the Community Fund will allow HPE to seek PUC approval of this program to earn bankable credits for use in future years, which will benefit all ratepayers.

Hyde Park will be addressing energy transformation programs to help decrease fossil fuel usage and comply with this RES requirement. We will begin with the base case as being open for purposes of filling it completely with the optimal scenario. Below in Figure 50 shows the estimated coverage and shortfall of Tier III. This short position will weigh heavily on the resource options that will be assessed in each of Hyde Park's scenarios.

[41] Docket No. 8550

Figure 50 Hyde Park's Tier III Forecast



G.1.4 Renewable Energy Credit Arbitrage

The rules regarding Tier I qualification is that a provider, such as HPE, "may use renewable energy with environmental attributes attached or any class of tradeable renewable energy credits generated by any renewable energy plant whose energy is capable of delivery in New England." (Act 56 of 2015). Because of this rule, Hyde Park has the ability to create REC arbitrage. The meaning of arbitrage is "the simultaneous purchase and sale of the same securities, commodities, or foreign exchange in different markets to profit from unequal prices."[42] Hyde Park can assess the market, and if its renewable energy credits are more valuable to sell in its qualified markets than buying other class RECs, HPE will sell the RECs it owns and buy back another class or state REC that is available at lower prices. This ability can help HPE buy down RES compliance payments in other Tiers where it may have a shortfall.

[42] http://www.dictionary.com/browse/arbitrage

G.2 RES modeling

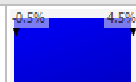
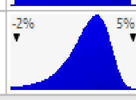
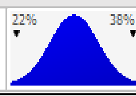
The Energy New England Portfolio Simulation Model, which is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables, was used to asses HPE's RES positions.

The process then used the ranges of estimated values to identify the key drivers of the REC portfolio performance. The stochastic simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Hyde Park's REC portfolio under different conditions and identifies the factors to which the performance is most sensitive. A major benefit of using a simulation method is the ability to apply thousands of different scenario conditions across all of the model inputs, which ultimately produces a distribution of possible outcomes.

G.2.1 Model Assumptions

Table 20: @Risk Model Inputs for RES Net Present Value

RISK Model Inputs

Name	Worksheet	Cell	Graph	Function	Min	Mean	Max
ategory: <none>							
Interest Rate	CPI	S12		RiskUniform(-0.0035108,0.042292,RiskName("Interest Rate"))	-0.35%	1.94%	4.2292%
CPI Rate	CPI	T12		RiskExtvalueMin(0.027403,0.0092604,RiskName("CPI Rate"))	-∞	2.21%	+∞
ategory: REC Percentage							
REC Percentage / Cal 2017	RES Breakdown	B26		RiskNormal(0.3,0.03,RiskStatic(0.3))	-∞	30.00%	+∞

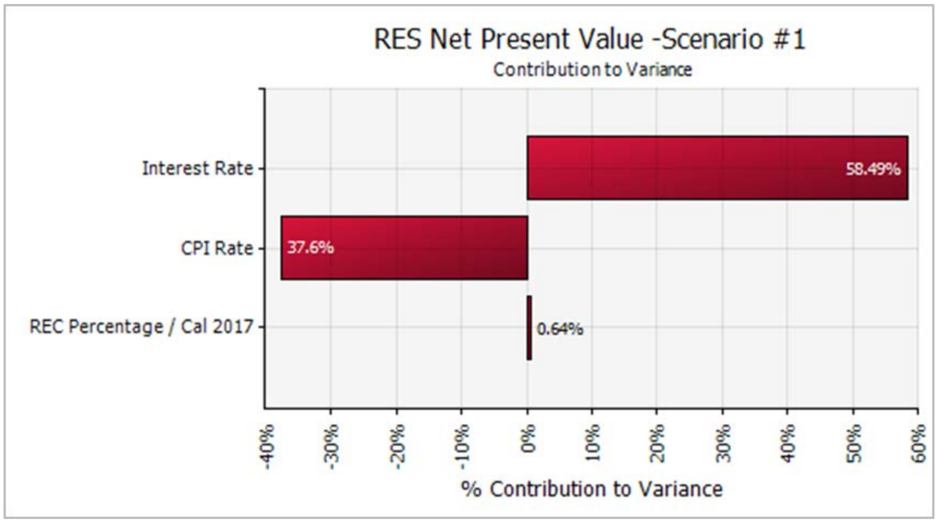
G.2.1.1 RES Tier Compliance rates use the CPI adder

G.2.1.2 Existing REC Market uses the CPI adder

G.2.1.3 Class I MA REC Market uses the MA compliance rate (using the CPI adder) and the REC market is a percentage of the compliance rate

G.2.1.4 Net Present Value uses the Interest Rate from the historical 22 years of Northeast Urban Consumer Price Index.

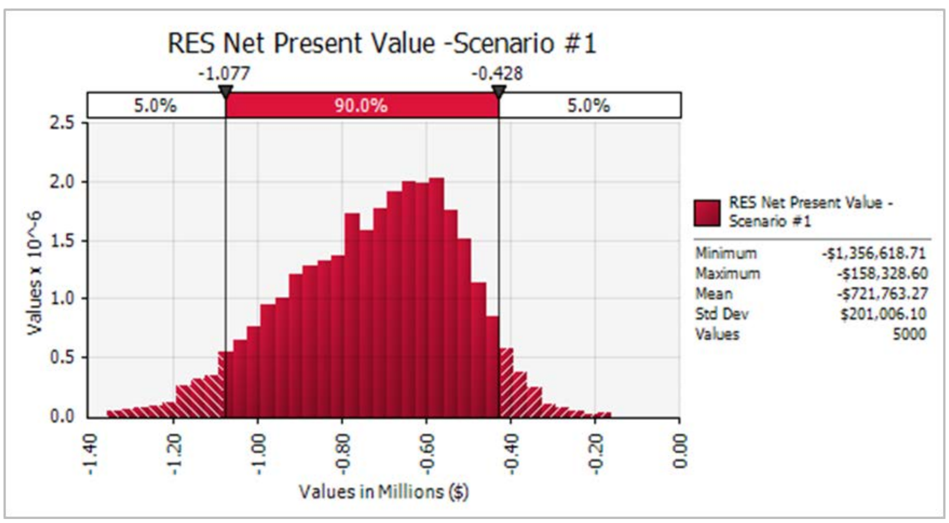
Figure 51 RES Tornado Chart of Inputs



G.2.2 Model Outputs

Appendix C contains the modeling report for the RES base case Net Present Value.

Figure 52: Net Present Value of RES for Hyde Park



G.3 Existing Capacity Resources

Hyde Park currently has around 17% of their 19-20 Forward Capacity Market Obligation covered with capacity resources, as seen below in Figure 53.

The open capacity position is charged at the net regional clearing price for the month. The rates are known through May 2024, as seen in **Table 21**, for Rest of Pool and Northern New England location, where Hyde Park will be charged for Capacity. The 23-24 Auction took place in February 2019.

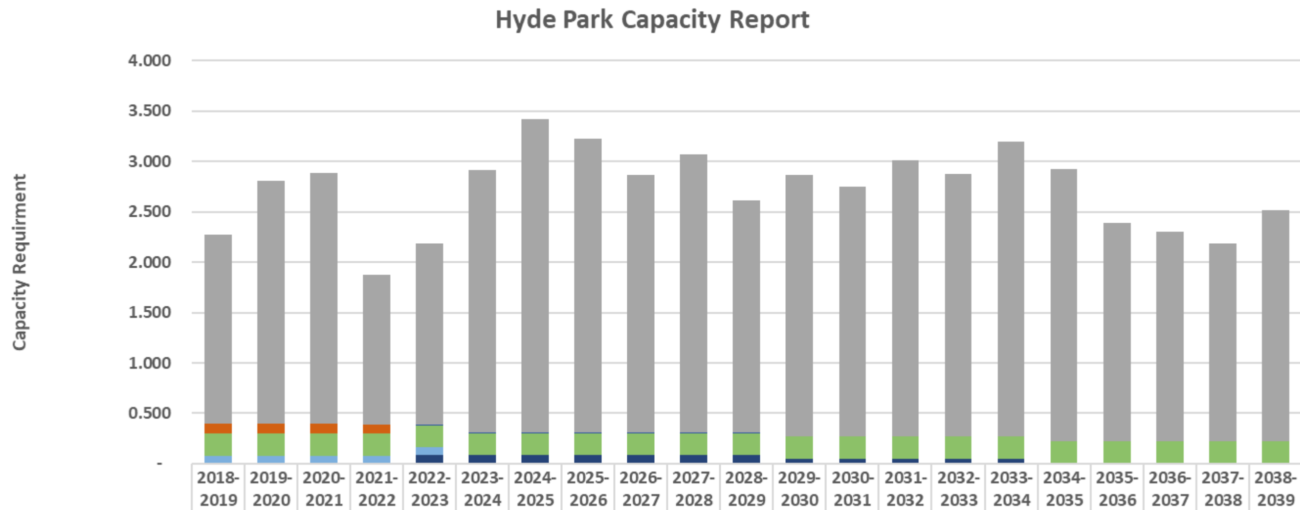
The most recent Capacity auction began on February 4, 2019 for FCM 13, which will begin on June 1, 2022 through May 31, 2023. The latest self-supply designation window was completed on October 29, 2018 for FCM 13. The auction for FCM 13 was the "first run under the Competitive Auctions with Sponsored Policy Resources (CASPR) rules, which include a substitution auction where resources interested in retiring can trade their capacity supply obligation to new state-sponsored resources that didn't clear in the primary auction."[43] FCM 13 had three locations the Southeast New England "SENE" (encompassed NEMA, SEMA, and RI), the Northern New England "NNE" (encompasses ME, VT and NH), and the Rest of Pool Zone (CT, and WMASS). In this auction, all locations cleared at the same price of $3.80/kW-month, which is the lowest price since FCA 7 back in 2013.

This auction had no price separation in any zone except for New Brunswick. NNE was modeled as export constrained while SENE was modeled as important constrained. The Resource MW's totaled 34,839 comprising of 29,611 MW of existing and 783 MW of new resources, as well as 654 MW of Demand Response. In this auction, there was one new large generator of 650MW in Connecticut. The DR and energy efficiency totaled 4,040 MW cleared which was roughly 11% of the total. Lastly, Vineyard Wind assumed an obligation of 54 MWs from a retiring resource.

Pay for Performance incentive began in FCA 9 (June 2018- May 2019). The rate paid and rewarded is the same $2,000 MWH. This rate will increase through the later capacity years beginning in FCA 12 to $3,500/MWH. There has been one Scarcity Event on September 3, 2018.

[43] http://isonewswire.com/updates/2019/2/28/finalized-capacity-auction-results-confirm-fca-13-procured-s-1.html

Figure 53: Hyde Park's Capacity Forecast



	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033	2033-2034	2034-2035	2035-2036	2036-2037	2037-2038	2038-2039
Market	1.870	2.410	2.483	1.491	1.802	2.614	3.116	2.924	2.559	2.766	2.306	2.597	2.474	2.743	2.604	2.923	2.703	2.171	2.082	1.964	2.298
Seabrook - Bilateral	0.100	0.100	0.100	0.083	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VEPPI SPEED	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
NYPA	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221
VEPPI	0.078	0.078	0.078	0.078	0.078	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seabrook - Bilateral	-	-	-	-	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.050	0.050	0.050	0.050	0.050	-	-	-	-	-

Table 21: Capacity-Clearing Prices

Load Obligation Charge			
FCA	Date	RoP	NNE
FCA9	2018-2019	$ 9.551	$ -
FCA10	2019-2020	$ 7.071	$ -
FCA11	2020-2021	$ 5.530	$ 5.268
FCA12	2021-2022	$ 4.961	$ 4.613
FCA13	2022-2023	$ 3.800	$ 3.800

G.4 Capacity modeling

The Energy New England Portfolio Simulation Model, which is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables, was used to asses HPE's Capacity positions.

The process then uses the ranges of estimated values to identify the key drivers of the Capacity portfolio performance. The stochastic simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Hyde Park's Capacity portfolio under different conditions and identifies the factors to which the performance is most sensitive. A major benefit of using a simulation method is the ability to apply thousands of different scenario conditions across all of the model inputs, which ultimately produces a distribution of possible outcomes

G.4.1 Model Assumptions

The IRP's capacity forecast is shown in the Capacity Market section. Below are the $/kw-mo. forecasted charges that ENE's simulation exported for each IRP year. The historical data (June 2010 through May 2023) used includes clearing prices and payment rate percentages of the historical clearing price to the payment rates. ENE used a risk simulation table that weighted five scenarios based on the percentage of the past three-year FCM clearing prices. Using FCA 11 through FCA 13 was the most ideal because they are the results from the most recent capacity parameters.

Figure 54: @Risk Model Prices for Capacity Forecast

Category: Stochastic Spot FCM Price, $kw-mo							
Stochastic Spot FCM Price, $kw-mo / 5/31/2024	FCM	P14	1 9	RiskTriang(P11,P10,P9)	1.564	4.492	8.003456
Stochastic Spot FCM Price, $kw-mo / 5/31/2025	FCM	Q14	1 9	RiskTriang(Q11,Q10,Q9)	1.603	4.605	8.203543
Stochastic Spot FCM Price, $kw-mo / 5/31/2026	FCM	R14	1 9	RiskTriang(R11,R10,R9)	1.643	4.720	8.408631
Stochastic Spot FCM Price, $kw-mo / 5/31/2027	FCM	S14	1 9	RiskTriang(S11,S10,S9)	1.684	4.838	8.618847
Stochastic Spot FCM Price, $kw-mo / 5/31/2028	FCM	T14	1 9	RiskTriang(T11,T10,T9)	1.726	4.959	8.834318
Stochastic Spot FCM Price, $kw-mo / 5/31/2029	FCM	U14	1 10	RiskTriang(U11,U10,U9)	1.769	5.083	9.055176
Stochastic Spot FCM Price, $kw-mo / 5/31/2030	FCM	V14	1 10	RiskTriang(V11,V10,V9)	1.814	5.210	9.281555
Stochastic Spot FCM Price, $kw-mo / 5/31/2031	FCM	W14	1 10	RiskTriang(W11,W10,W9)	1.859	5.340	9.513595
Stochastic Spot FCM Price, $kw-mo / 5/31/2032	FCM	X14	1 10	RiskTriang(X11,X10,X9)	1.905	5.473	9.751434
Stochastic Spot FCM Price, $kw-mo / 5/31/2033	FCM	Y14	1 11	RiskTriang(Y11,Y10,Y9)	1.953	5.610	9.99522
Stochastic Spot FCM Price, $kw-mo / 5/31/2034	FCM	Z14	1 11	RiskTriang(Z11,Z10,Z9)	2.002	5.751	10.2451
Stochastic Spot FCM Price, $kw-mo / 5/31/2035	FCM	AA14	2 11	RiskTriang(AA11,AA10,AA9)	2.052	5.894	10.50123
Stochastic Spot FCM Price, $kw-mo / 5/31/2036	FCM	AB14	2 11	RiskTriang(AB11,AB10,AB9)	2.103	6.042	10.76376
Stochastic Spot FCM Price, $kw-mo / 5/31/2037	FCM	AC14	2 12	RiskTriang(AC11,AC10,AC9)	2.156	6.193	11.03285
Stochastic Spot FCM Price, $kw-mo / 5/31/2038	FCM	AD14	2 12	RiskTriang(AD11,AD10,AD9)	2.210	6.348	11.30867
Stochastic Spot FCM Price, $kw-mo / 5/31/2039	FCM	AE14	2 12	RiskTriang(AE11,AE10,AE9)	2.265	6.506	11.59139
Stochastic Spot FCM Price, $kw-mo / 5/31/2040	FCM	AF14	2 12	RiskTriang(AF11,AF10,AF9)	2.322	6.669	11.88118

G.5 Assessment of Alternative Resources

When assessing different portfolio strategies, Hyde Park's focus is RES compliance. Therefore, the scenarios that were heavily focused on were to include either one or a combination of wind, solar, and hydro. Because HPE has a large short position of Tier I analyzed projects that were compliant renewables against Tier I to see which suited HPE's portfolio the best. The goal for the resources was to get HPE to the max RES compliance. Tier I was the important driver to fill, because the Waterhouse Solar Project covers HPE's Tier II completely.

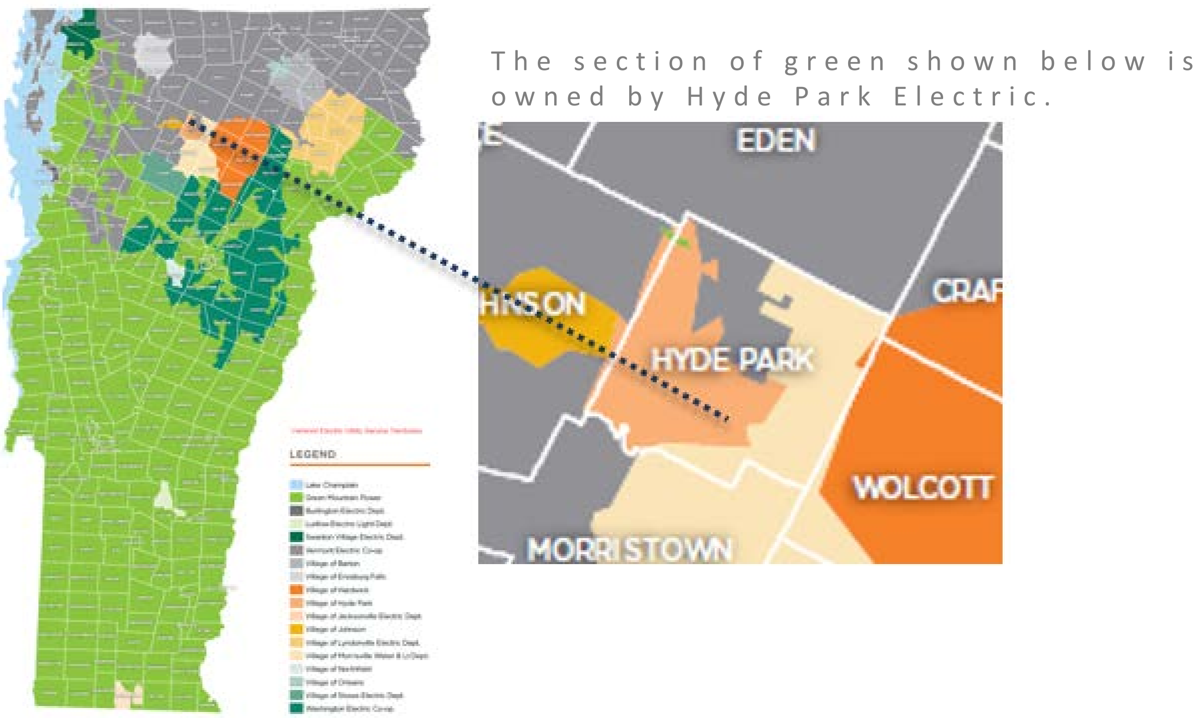
H Assessment of the Transmission and Distribution System

H.1 T & D System Evaluation

Hyde Park Electric ("HPE") service territory is located in Lamoille County in north central Vermont encompasses the Village as well as portions of the Town of Hyde Park and Johnson. HPE serves approximately 1,398 retail customers. The area of the service territory is approximately 18 square miles. The system's largest electrical customer is Lamoille Union High School. Hyde Park connects to the transmission system of Green Mountain Power (GMP).

The HPE distribution system includes approximately 53 miles of aerial lines and 9 miles of underground lines. The HPE distribution system has been changed from #6, #4 and #2 copper wire to 1/0 AAAC Azusa, and small sections of #2 AAC. The distribution voltage is 12,740/7,200 grounded wye with the exception of the line feeding Lamoille Union High School, which is 12,000 Delta.

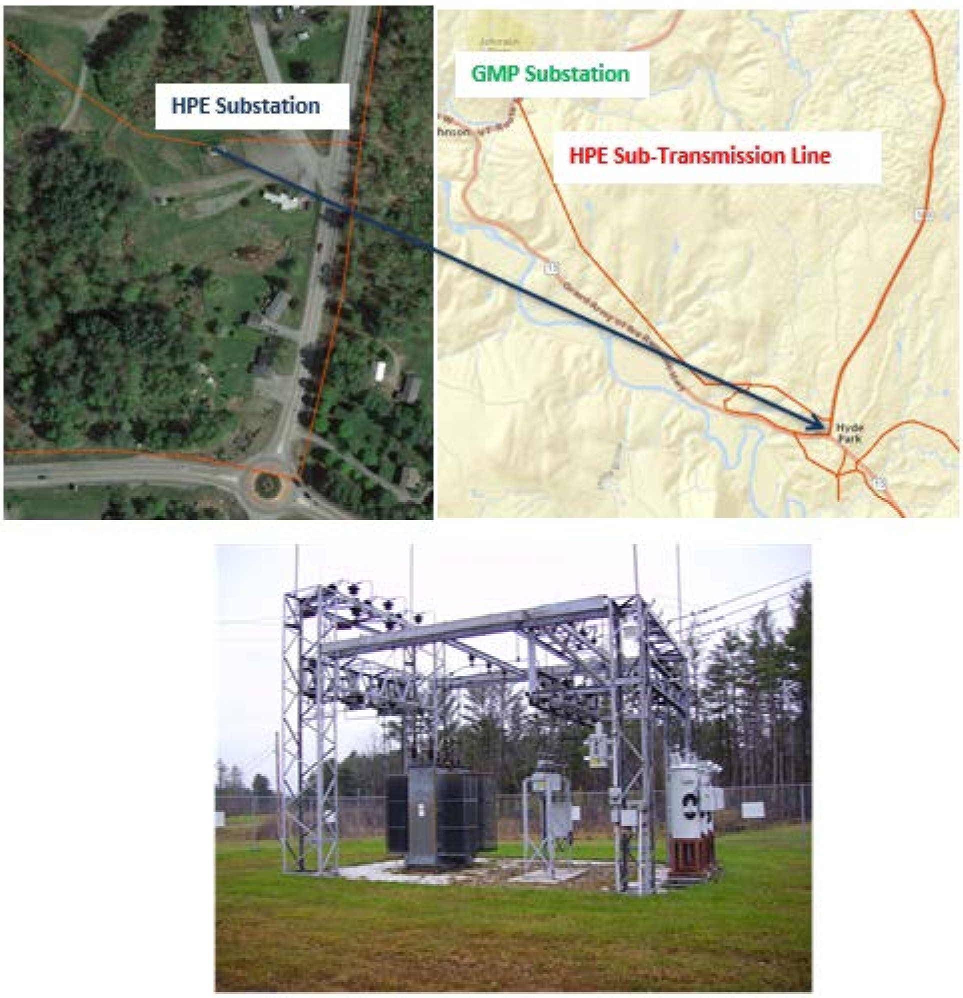
Figure 55 System Service Territory



H.1.1 Substation

The single HPE substation is supplied at 34.5 kV via an approximately 19,000 foot sub-transmission line of 3/0 ACSR overhead conductor from the Johnson substation owned by Green Mountain Power (“GMP”) on the B20 line.

Figure 56 HPE Substation and GMP Substation

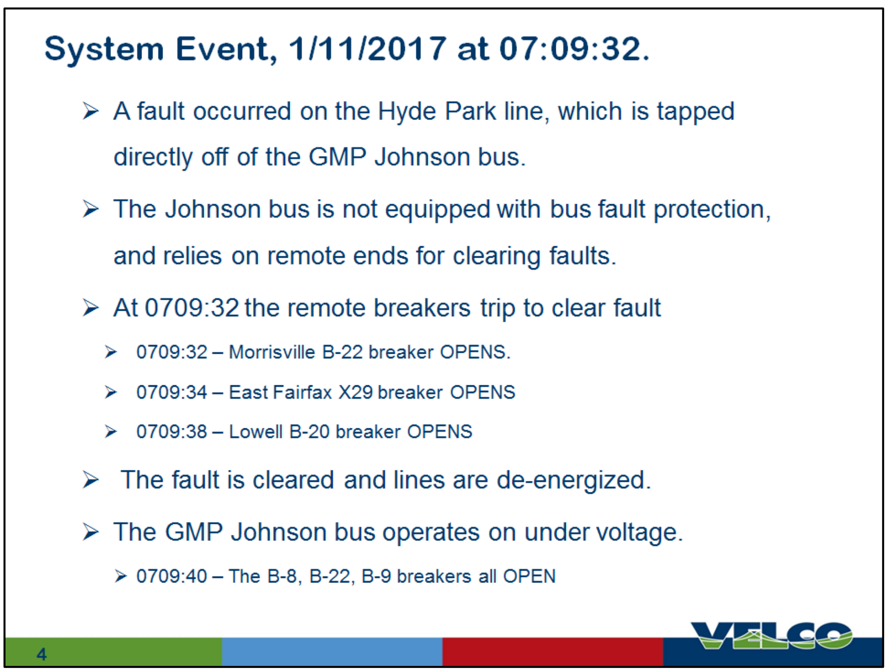


The HPE substation is located at the intersection of Hwy 100 and Battle Row Road, just north of the roundabout connecting highways 100 and 15. The substation is equipped with a General Electric three-phase 34kV-12.47kV transformer with a base nameplate rating of 5.0 MVA and protected by an ABB recloser with three Cooper CL6 regulators on the distribution side of the recloser. A Vermont Electric

Cooperative engineer implemented the settings at the recloser and these settings were verified by ControlPoint consulting engineers in 2017. All distribution side-taps are fused.

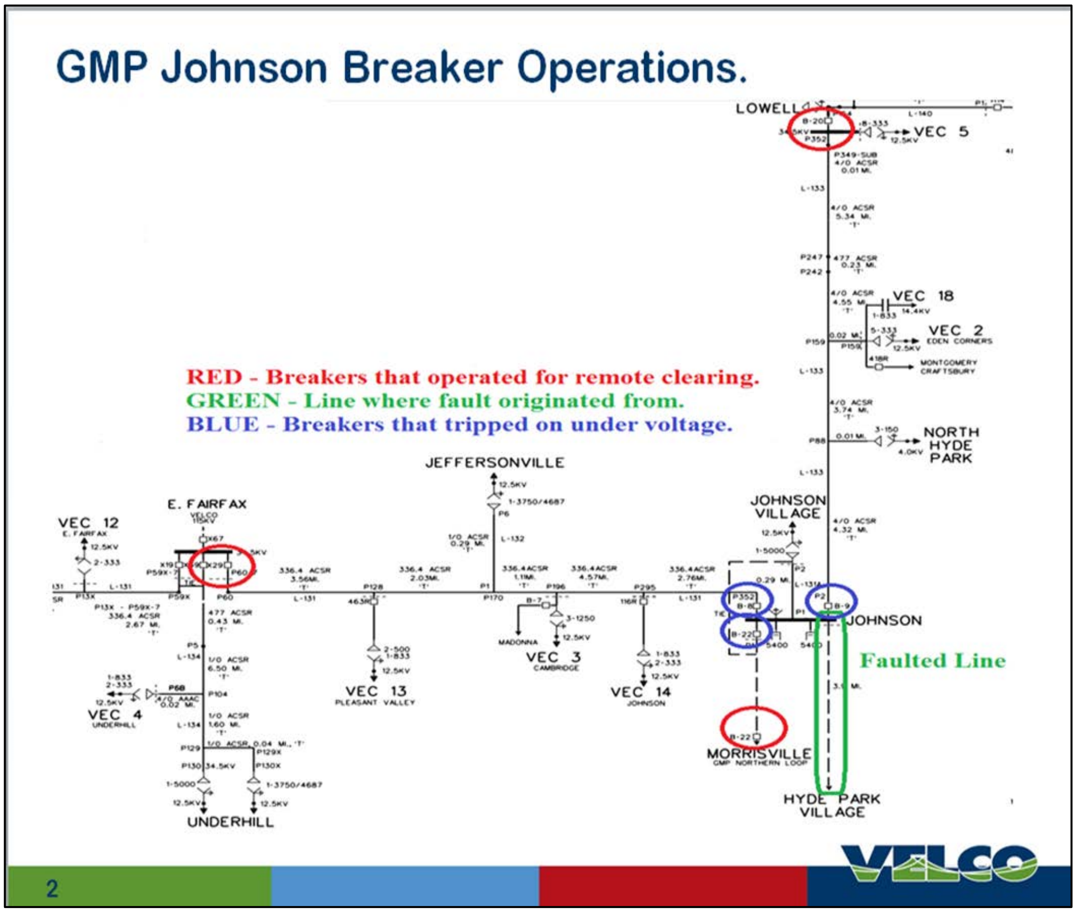
To improve safety and reliability, we plan to address aged substation infrastructure by engaging in engineering studies, financial evaluations and regulatory approvals during the period of 2020-2022. We anticipate either significant upgrades at the current substation site or the relocation and build of a new substation. HPE purchased the North Hyde Park substation from GMP in November 2013 and this location is the alternative relocation site. Both sites connect with GMP's B20 line. HPE's substation transformer was purchased from Lyndonville Electric in 1968 and it was previously located at a government radar station. The transformer age well exceeds 60 years and station equipment is obsolete. Upgrades will include installation of a new transformer, oil containment, circuit breakers, relay protection upgrades and associated fence, ground grid, and communications. We estimate this project at $1.5 million. The site is not currently in use. The possible relocation of the substation was discussed with GMP at the time that they noticed HPE that GMP had decided to install a reclosure in the Johnson Substation in response to the System Event described in the VELCO report that follows.

Figure 57 GMP Substation System Event



HPE commissioned professional engineers to support in discussions with the transmission operators, GMP and VELCO, as they conducted a review of transmission protection. ControlPoint and GMP agreed that the installation of a recloser was not feasible due to the BIL limitations. In September 2017, GMP planned to replace the GMP Johnson Substation transmission fuses in series, allowing GMP to pick up load with HPE 114 Air Break rather than the fuses. In 2019, GMP noticed HPE that they had decided that a breaker provided a better solution and that were installing a breaker in the Johnson Substation in 2019.

Figure 58 GMP Johnson Substation One-Line Diagram



The Vermont Department of Public Service updated the Vermont Comprehensive Energy Plan (“CEP”) in 2016. The 2016 CEP included guidance for IRPs. Relevant to this section of HPEs IRP, the CEP included specific questions that utilities are to use to evaluate their transmission and distribution systems.

HPE's assessment follows below.

1. *The utility's power factor goal(s), the basis for the goals(s), the current power factor of the system, how the utility measures power factor, and any plans for power factor correction.*

In 1997, at the time of the last "PLM Study," HPE's peak load power factor was estimated at 92%. Recommendations were followed and HPE installed 600kvar of distribution capacitors (300 knar fixed and 300 kVAR switched) for power factor corrections. This corrected the system power factor to 98% on peak with a resulting peak load loss reduction and associated savings. HPE does not currently monitor power factor. While HPE believes that it is above the DPS's desired levels as a result of the system capacitor upgrades, it does not have load data needed to accurately correct power factor. We plan to analyze feasible and cost-effective options to collect the required data, measure the power factor and implement a program to improve.

2. *Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for backup.*

HPE entire distribution system voltage is 12,470/7,200 grounded wye, and wire is 1/0 AAC and 1/0 Hendrix Cable (tree wire) where needed. Phase balancing is tracked on a monthly basis and the results have been satisfactory. HPE installed a metered backup distribution feed from Morrisville Water and

Light Department's distribution on VT Route 15 & 100. Back-up is also available by feeding from Morrisville transmission to its transmission by a switch near the Lamoille North Superintendent's office.

HPE 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 Rule 4.900 Outage Reports and data collected from load loggers. In addition, HPE periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. 2017 was the most recent system planning study. The cost of the recommended improvements developed into a 5-year budget and approved by the Board of Trustees based upon the financial position of HPE.

In 2017, HPE commissioned a professional engineering firm to perform a protection review and circuit analysis. The 2017 Protection Review and Circuit Analysis by ControlPoint professional engineers accomplished the following tasks:

1. Root Cause Analysis
    a. Provide Protection Recommendations for Open-Phase Detection
2. Protection Coordination Analysis

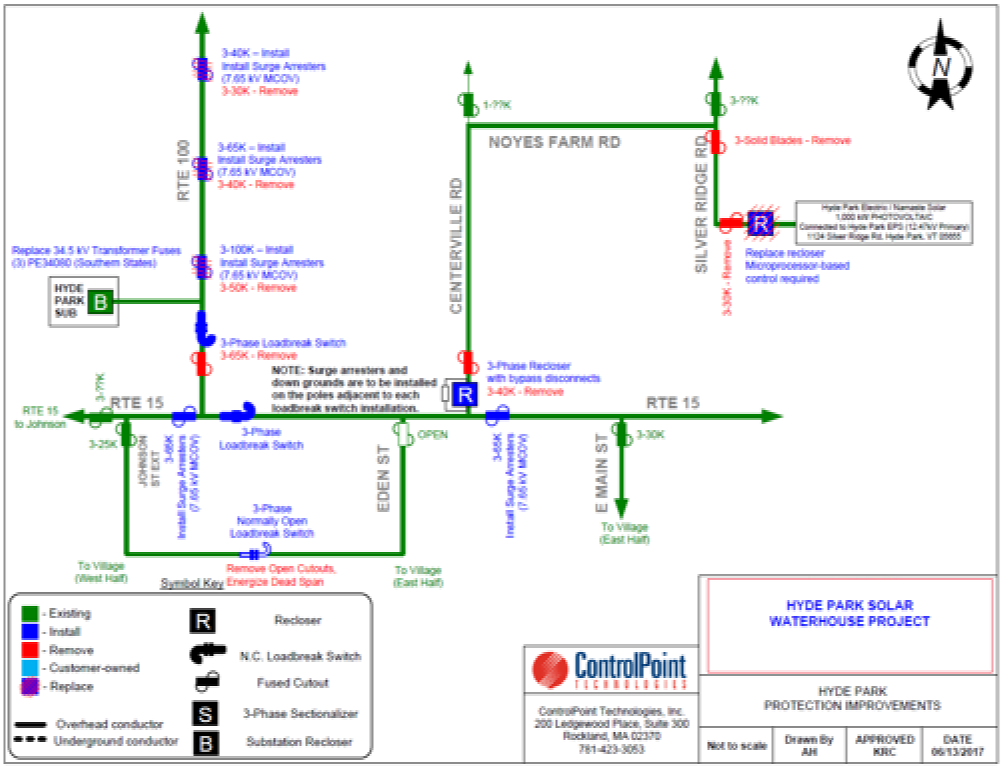
a. Create Distribution Short Circuit Model - ASPEN Model
b. Protection and set point coordination studies
c. Transformer winding configuration review at PCC
d. Address circuit selectivity and fault sensitivity, temporary overvoltage, and transient issues for anti-islanding protection.
e. Address ground fault protection and DG source issues at the supply to the substation source and at the PCC.
f. Analyze equipment-interrupting ratings
g. Review Protective Device Coordination and develop Relay Settings as required
h. Relay Settings following the completion & acceptance of final engineering.

3. Grounding Analysis
    a. Grounding reviews - Including Transformer winding configuration review at PCC
    b. Verify effective grounding of interconnection system
4. Analyze Islanding Risk and support fault sensitivity and transient analysis for Anti-Islanding Study.
    a. Anti-Islanding Study by ControlPoint through Northern Plains Power Technology.

Engineering support continued in HPE's discussions with the transmission operator, GMP, as they were conducting a review of transmission protection. ControlPoint assistance focused on

1. Assisting HPE in the specifying of equipment recommended in the 12.47 kV protection reviews
2. Engineering support for HPE during the 35 kV transmission protection reviews conducted by GMP
3. Engineering support for the discussions with the transmission operator, GMP, as they conducted a review of transmission protection on the line serving HPE
4. Engineering support to specify equipment to order for construction, with plans in the future to replace the fuses with Southern States PE34080 fuses (GMP later decided to install a breaker.)

Figure 59 One- Line Diagram and Improvements



3. *Sub transmission and distribution system protection practices and philosophies.*

<u>Transmission and Sub-Transmission System protection</u>

The transmission system is protected by GMP and VELCO. HPE Sub-Transmission line is adequate until decisions are made in the 2020-2022 timeframe, as discussed in section H.1.1.

<u>Substation protection</u>

HPE substation equipment is protected by high side fuses. Vermont Electric Cooperative substation crew performed an inspection to include infrared. All maintenance recommendations were completed.

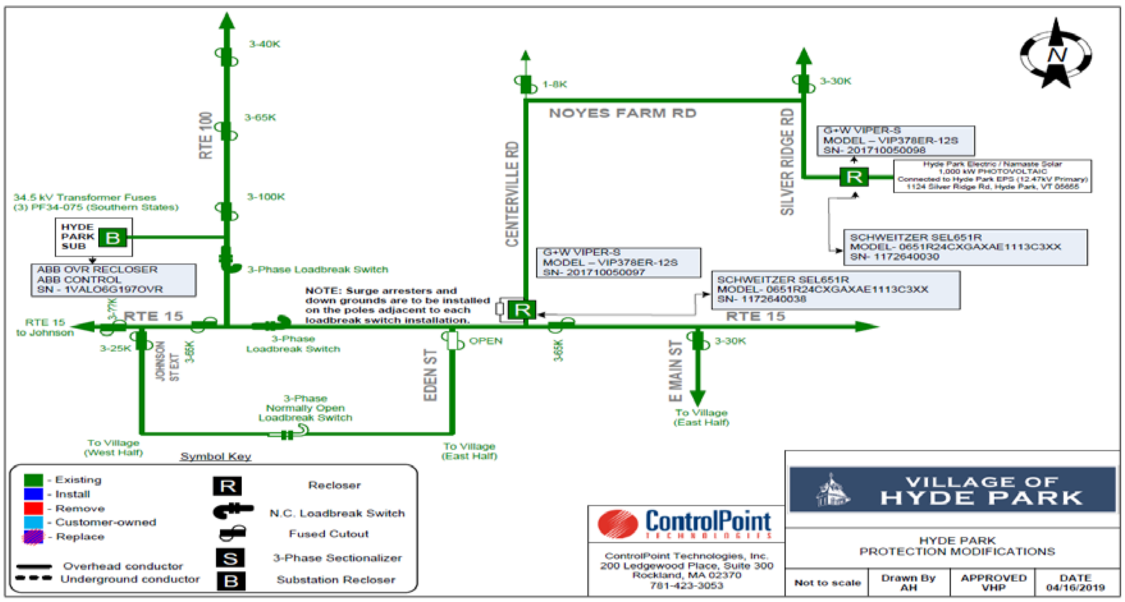
<u>Distribution protection</u>

HPE entire system voltage is 12,470/7,200 grounded wye and uses tree wire on primary overhead lines. Distribution system protection involves circuit reclosers and fuses. All side taps off the main line distribution feed are fused. Underground distribution is installed in conduit and at a depth of not less than 42 inches. Following the 2017 protection review and circuit analysis, ControlPoint assisted HPE in specifying the switches, reclosers, cutouts, and other equipment needed for system improvement. These improvements have been made.

We continue to install underground cable in conduit. We have an open architecture GIS map of three-phase lines and will move toward building GIS for both overhead and underground lines.

We employed ControlPoint to review Vermont Utilities Electric Service Requirements Manual with our Line Foreman to determine any areas in which HPE practices deviated from those contained in the manual. While HPE has not yet formally adopted the manual, staff has been instructed and trained to comply with the manual and in any instance that may deviate, to report to the GM. In those instances, we will seek guidance from an authoritative source.

Figure 60 HPE One Line Diagram



4. *The utilities planned or existing "smart grid" initiatives such as advanced metering infrastructure, SCADA, or distribution automation.*

HPE has not engaged in a professional cost/benefit analysis to determine if we should invest in advanced metering and system automation. Our simple analysis shows that it is not cost effective with the average monthly cost to read a meter less than $1.50. While reading meters, HPE staff inspects distribution lines, right-of-way and meters. When we forecast potential cost justification, we will engage a professional analysis and respond accordingly.

The ongoing participation of HPE and others in various facets of “smart grid” explorations has underscored both the challenges and the opportunities that lie ahead. On the challenge side, the cost effectiveness of AMI infrastructure is significantly less clear with very limited savings around meter reading combine with a terrain that challenges the efficacy of many wireless AMI systems. On the positive side, municipal smart grid summits and other events have shown that prospective electric-water-sewer AMI applications may have some efficiencies and synergies not available in electric only installations, and cost allocation in such situations done carefully to avoid subsidization issues. As we continue to collaborate with our Vermont utility colleagues regarding “lessons learned” from their experiences, HPE will be in a good position to make technically and financially sound decisions regarding the timing and specifics of the smart grid applications that will be coming.

HPE is of course mindful of the many facets of the evolving grid, such as rapidly expanding net metering development, heat pump installations, and the advent of electric vehicles. Working with Efficiency Vermont, and other stakeholders, HPE stays abreast of these developments and the strategies needed to maintain a safe, reliable, and economically viable distribution system.

HPE is also mindful of the increasing importance of cyber-security concerns, and the relationship of those concerns to technology selection and protection. HPE is not presently required to undertake NERC or NPCC registration. In 2018, HPE initiated CIS billing, general and work order accounting, and customer portal services by a services and support contract with Southeastern Data Cooperative, Inc. HPE is served by Oracle Advanced Security Software, and with Oracle Encryption Services protecting HPE and customer data. SEDC’s Technical Support Services Group will assist in managing the infrastructure and networking related to SEDC applications, including periodic checks and tuning on the Oracle database and monitoring for data issues.

5. *Re-conductor lines with lower loss conductors.*

All HPE distribution lines are 1/0 AZUSA Alum wire.

6. *Replacement of conventional transformers with higher efficiency transformers.*

HPE purchases new low loss transformers (amorphous core) for most all commercial, industrial and net-metering applications and rebuilt standard loss transformers for residential applications. Transformer data is provided by the supplier. We are assessing future purchases of amorphous core new transformers for residential applications.

7. *The utility's distribution voltage settings (on a 120V base) and whether the utility employs, or plans to employ, conservation voltage regulation or volt/VAR optimization.*

HPE utilizes voltage regulators in the substation, and voltage is set between 120 and 121.5 volts to provide proper voltage to the first and last customers. Waterhouse Solar has a voltage regulator, and otherwise HPE does not have voltage regulators outside the substation due to the short distance to last customers. HPE participates in the ISO-New England voltage reduction tests.

8. *Implementation of a distribution transformer load management (DTLM) or similar program.*

HPE is currently preparing a DTLM Program and commits to finalizing this program in 2020.

9. *A list of the location of all substations that fall within the 100 and 500 year flood plans, and a plan for protection or relocation of these facilities.*

HPE's substation does not fall within the 100 and 500 year flood plans.

10. *A discussion of whether the utility has Damage Prevention Program (DPP), or plans to develop and implement a DPP, if none exists.*

The vast majority of HPE's lines are overhead lines. HPE will have a Damage Prevention Plan approved and in practice before the next IRP. HPE requires inspection by HPE staff of all underground lines prior to burial. HPE participates in Dig Safe and responds with line personnel to mark all utility-owned underground lines. All primary underground lines are installed per HPE's specifications. HPE pulls all wire with its line crew. HPE does the same thing for itself (internally) as it does for Dig Safe. HPE follows and will continue to follow the Dig Safe rules. HPE installs all underground lines in conduit and at a depth of 42 inches.

11. *The location criteria and extent of the use of animal guards.*

HPE installs animal guards on all new construction and line replacements, and routinely adds animal guards with approximately 95% of transformers equipped.

12. *The location criteria and extent of use of fault indicators, or the plans to install fault indicators, or a discussion as to why fault indicators are not applicable to the specific system.*

HPE uses fault indicators as needed. There are currently no guidelines.

13. *A Pole inspection program, the plans to implement a pole inspection program, or a discussion as to why a pole inspection program is not appropriate to the specific utility.*

HPE presently does not have an outside contractor perform comprehensive pole inspection, testing and treatment program. Our program is internal and with the heavy installation of television cable in recent years, pole inspection is a routine activity of our staff. HPE has replaced many poles over the last thirty years, as lines were moved to the roadside. We now have line staff trained and equipped to maintain a spreadsheet record of visual inspection and replacement schedule.

14. *The impact of distributed generation on system stability.*

Currently, HPE has 38 solar net metering customers with a combined total installed capacity of 518.96 kW, and combined with our 1 MW Hyde Park Solar Farm, we are experiencing times of excess internal generation. Additional growth in small net-metering systems will require HPE to expend more funds for engineering analysis and equipment in the future.

Consistent with ISO New England requirements related to inverter "ride-through" settings, HPE will require owners/ developers of all new DER installations to self-certify installation of inverters compliant with the Inverter Source Requirement Document (SRD) of ISO New England, with settings consistent with IEEE 1547-2018 and UL 1741 SA. This document is included as Appendix K at the end of this document. HPE recognizes the need to standardize efforts aimed at certifying inverter compliance with the ISO SRD and will work with the PSD to achieve use of common forms and process in this regard.

H.2 T & D Equipment Selection and Utilization

The most recent construction and ownership of Waterhouse Solar Project continues HPE commitment to independent professional expert analysis to determine the net present value of life cycle cost as well as the societal and ratepayer impacts. For routine distribution equipment, HPE purchases standard certified equipment from established qualified vendors, and as needed utilizes consulting engineering firms to specify equipment and recommend vendors. Our purchasing policy defines an appropriate bid process for quality materials and equipment. HPE maintains a minimal inventory of distribution transformer sizes, both pole and pad mounted, on hand for new installations and replacements. HPE also purchases quality equipment directly from other public power and cooperative inventories and contracts with other public power and cooperative systems for metering and technical expertise. HPE believes that there are many benefits from this practice – reduces of fossil fuel used for transportation, saves money and time. Larger inventory deliveries to larger system's inventories versus single deliveries to small distribution systems can serve to reduce fossil fuel use. Larger inventories held by neighboring systems can turn at an acceptable and predictable rate as small systems pull their inventory needs. Larger distribution systems can gain volume discounts and these flow to the smaller systems. In times of outage, there should be a benefit of larger, more accessible local equipment and materials.

H.3 Implementation of T & D Efficiency Improvements

In 2017, HPE commissioned a professional engineering firm to perform a protection review and circuit analysis. HPE 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 Rule 4.900 Outage Reports and data collected from load loggers. In addition, HPE periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. The cost of the recommended improvements developed into a 5-year budget and approved by the Board of Trustees based upon the financial position of HPE.

Table 22 Line Loss

Line Loss	
2012	12.3%
2013	12.4%
2014	9.7%
2015	10.7%
2016	7.7%
2017	11.1%
2018	9.53%

Efforts to Reduce Losses

- Replaced small wire system wide with 1/0 Alum
- Converted entire system voltage to 12,470/7200 grounded wye
- 1MW Waterhouse Project, local solar generation in August 2016
- 2017 Protection Study and Circuit Review by ControlPoint engineering
- 2017 ControlPoint Engineering support for Johnson substation and with Green Mountain Power

H.4 Maintenance of T & D System Efficiency

HPE currently has an unwritten system maintenance program. We plan to develop a formal system maintenance program before the next IRP. HPE performs annual oil checks on substation transformers and monthly substation inspections. Documentation is retained and problems addressed as they occur.

H.5 Other T & D Improvements

HPE takes transmission service on the B-20 GMP transmission line. We have been informed that GMP is planning to make improvements to the line.

H.6 Vegetative Management Plan

HPE's distribution system is relatively small and compact making it easier to manage an effective vegetation management plan. HPE establishes and maintains fifty feet of right-of-way and trims with least disturbance possible. Distribution right-way program has been very effective in reducing customer disturbances although it is not a cut to the ground method throughout the system. Village residents and certain other Town residents are particularly eager to maintain a spacious tree canopy which typically results in additional time and resulting labor. HPE does not apply any herbicide, and projects spending $24,700 in 2019, increasing by 3% annually through 2024.

Over the previous thirty plus years, the transmission line right-of-way from the Johnson substation to the HPE substation requires a trimming cycle of about ten years. Outages that occur on this line are due to fallen trees growing outside of the right-of-way. Transmission right-of-way clearing means cut to the ground. HPE line staff is now skilled and equipped to create and maintain a computerized database of right-of-way activity to assure best practices and least cost, and will have this program in place prior to the next IRP. Based on the good condition of our distribution right-of-way, The Town of Hyde Park does not offer a detailed system wide tree inventory with information to assist us in species evaluation relative to the right-of-way program. The Town Tree Warden is available for guidance, as needed in special cases.

In addition to its vegetative and brush management program, HPE routinely identifies danger trees within its rights-of-way, and then either "trims-to-safe-condition" or removes the trees. Danger trees are identified by utility personnel while patrolling the lines, reading meters, working on or inspecting the system. In many instances, the public reports danger trees. A danger tree is removed if found within HPE right-of-way. For danger trees outside of the right-of-way, HPE contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission not granted, HPE periodically communicates with the property owner to attempt to obtain permission. In many cases, the Town will assist in debris removal if the Town determines that a danger tree may also endanger to a Town road.

HPE territory has a variety of trees: maple, cherry, poplar, white and brown birch, white and red pine, spruce, hemlock, balsa, apple, elm, a scarce amount of oak and ash. The emerald ash borer has not yet become an active issue in HPE's territory. HPE is monitoring developments and coordinating efforts with VELCO and will make use of any guidance that becomes available as a result. If and when the emerald ash borer does surface in HPE's territory, affected trees will be cut down, chipped and disposed of properly.

Table 23 Vegetation Plan

	Total Miles	Trimming Miles	Cycle Years
Transmission	4	4	10
Distribution	54	11	5

Right-of Way	2013	2014	2015	2016	2017	2018
	Actual	Actual	Actual	Actual	Actual	Actual
Budget	$21,800	$34,600	$34,600	$24,000	$24,480	$24,700
Spent	$31,728	$26,140	$26,917	$9,057	40,908	20,300
Miles Trimmed	3.5	3	3	1	3.5	1.9
Total Outages		2,144	8,162	433	6,723	3,809
Tree Related		33%	82%	16%	8%	92%
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
	Projected	Projected	Projected	Projected	Projected	Projected
Budget	$24,700	$25,441	$26,204.23	$26,990	$27,800	$28,634
Spent	X	X	X	X		
Miles Trimmed	2.3	2.3	2.3	2.3	2.3	2.3

H.7 Studies and Planning

H.7.1 Sub-Transmission

HPE will engage in engineering and financial evaluations to determine the least cost, reliable alternative to the current sub-transmission line in the period 2020-2022.

H.7.2 Distribution

The following are HPE historical capital expenditures and HPE future capital needs for the distribution system.

Table 24 Capital Report

Hyde Park Electric
Capital Expenditures

Acct #	Description	2016	2017	2018
3640	Poles, Towers, Fixtures		$ 2,133	
	Substation Equipment		$ 3,088	
3680	Line Transformers			
3650	Overhead Conductors and Devices			
3660	Underground Conduit			
3670	Underground Conductors and Devices			
3690	Services			$ 174
3700	Meters		$ 1,000	
3730	Street Lights and Signal Systems			
3910	Office Furniture & Equipment	$ 4,911	$ 1,369	
3910	IT Hardware			$ 84,017
3920	Transportation	$ 55,322	$ 29,437	$ 44,644
3940	Tools, Shop, & Garage Equipment	$ 3,437	$ 4,214	
	Construction-Work-In-Process		$ 22,842	
	Total Expenditures	**$ 63,670**	**$ 64,083**	**$ 128,835**

Hyde Park Electric
Projected Capital Needs

Acct #	Description	Additions 2019	Additions 2020	Additions 2021	Additions 2022	Additions 2023
3640	Poles, Towers, Fixtures	$ 6,000	$ 6,102	$ 6,206	$ 9,308.60	$ 9,467
3680	Line Transformers	$ 2,275	$ 2,314	$ 2,353	$ 3,529.51	$ 3,706
3650	Overhead Conductors and Devices	$ 1,027	$ 1,045	$ 1,062	$ 1,593.69	$ 1,621
3660	Underground Conduit	$ 300	$ 305	$ 310	$ 465.43	$ 473
3670	Underground Conductors and Devices	$ 1,470	$ 1,495	$ 1,520	$ 1,546	$ 1,573
3690	Services	$ 200	$ 203	$ 207	$ 210	$ 214
3700	Meters	$ 500	$ 509	$ 517	$ 776	$ 789
3730	Street Lights and Signal Systems	$ 900	$ 915	$ 931	$ 947	$ 963
3910	Office Furniture & Equipment		$ 2,000	$ 1,000	$ 2,000	$ 2,000
3910	IT Hardware	$ 16,500	$ 2,000	$ 1,500	$ 2,000	$ 2,000
3920	2003 Digger Truck (purchased 2013)			$ 25,000	$ 25,000	$ 25,000
3940	Tools, Shop, & Garage Equipment	$ 4,000	$ 4,068	$ 4,137	$ 6,205.73	$ 6,311
	SUBSTATION				$ 750,000.00	$ 750,000
	Capital Needs	**$ 33,172**	**$ 20,956**	**$ 44,744**	**$ 803,582**	**$ 804,116**
	TOTAL					**$ 1,706,570**

H.8 Emergency Preparedness and Response

Customers have 24/7 access to HPE for all emergencies by calling our main phone number or the afterhours phone number. Like other Vermont municipal electric utilities, HPE is an active participant in the Northeast Public Power Association ("NEPPA") mutual aid system, which allows HPE to coordinate with public power systems in Vermont, and with those throughout New England. A HPE representative is also on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties. HPE uses the www.vtoutages.com site during major storms especially if it experiences a large outage expected to have a long duration. Outage information is input manually. HPE believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. HPE assists with neighboring municipals and cooperatives when extra crew power is required. HPE very rarely uses or requires contract crews.

For planned outages, HPE uses several forms of communications to inform customers in advance: phone calls, emails, and door notices. Information may also be posted on Front Porch Forum, www.villageofhydepark.com, Twitter, and Facebook, as time permits.

H.9 Reliability

HPE tracks all outage statistics as part of its Service Quality Reliability Plan (SQRP). The following table summarizes SAIFI and CAIDI results for the past five years. Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years (2014-2018) in their entirety, can be found at the end of this document. HPE has committed to achieve performance levels for its distribution system below an index of 2.6 for SAIFI and 1.9 for CAIDI.

Table 25 SAIFI and CAIDI summarizes Hyde Park's SAIFI and CAIDI values for the years 2014 – 2018, with all outages included.

Table 25 Hyde Park's SAIFI and CAIDI values

	Goal	2014	2015	2016	2017	2018
SAIF	**2.6**	1.6	1.3	0.3	1.6	1.5
CAIDI	**1.9**	1	4.7	1.1	3.1	1.9

H.9.1 Assessment of Outage Events and Trends

In 2018, trees located out of the right-of-way fell onto distribution lines late in the evening and morning hours, which delayed restoration. High wind was the primary cause. In 2017, we experience several vehicle accidents that took down poles and/or distribution lines. The outage listed as "Other" is the GMP Substation event described previously in Appendix L . In general, we have somewhat improved in equipment reliability and have maintained adequate reliability while placing the safety of our crew and the public.

Table 26 Circuit #1 Outage Report

Electricity Outage Report for HPE Circuit #1					
	Outage Cause	#	Total Customer Hours Out	SAFIFI	CAIDI
2018	Trees	23	3503		
	Weather	2	188		
	Equipment Failure	4	21		
	Animals	3	30		
	Other	1	1		
	Unknown	6	66		
	Total 2018	**39**	**3809**	**1.5**	**1.9**
2017	Trees	13	524		
	Weather	2	83		
	Equipment Failure	4	32		
	Accidents	2	1322		
	Animals	2	101		
	Other	3	4727		
	Unknown	3	34		
	Total 2017	**29**	**6823**	**1.6**	**3.1**
2016	Trees	5	68		
	Weather	2	109		
	Equipment Failure	4	30		
	Animals	2	39		
	Unknown	6	187		
	Total 2016	**19**	**433**	**0.3**	**1.1**
2015	Trees	2	6,721		
	Weather	4	93		
	Equipment Failure	5	91		
	Animals	2	0		
	Other	1	6		
	Unknown	9	1,251		
	Total 2015	**23**	**8,162**	**1.3**	**4.7**
2014	Trees	6	717		
	Weather	2	870		
	Equipment Failure	7	415		
	Accidents	2	140		
	Animals	1	1		
	Unknown	1	1		
	Total 2014	**19**	**2144**	**1.6**	**1**

I Integrated Analysis and Plan of Action

I.1 Evaluation of Portfolio Scenarios

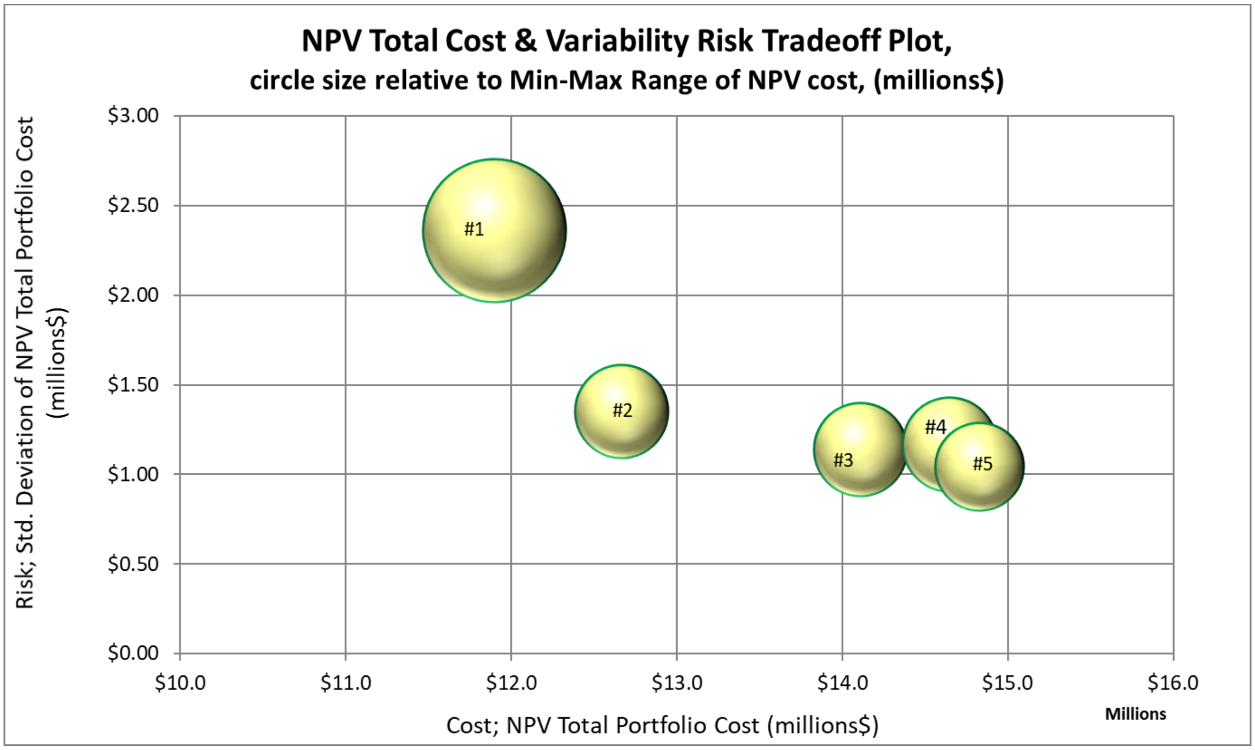
ENE’s portfolio simulation models evaluated five (5) scenarios that consisted of varying amounts of resources and fuel type. Scenario #1 is the base case, which is the “do nothing” current portfolio. ENE analyzed each scenario from both the energy perspective and the RES contribution to compliance perspective. Below are all the scenarios, categorized by number for clarification.

Portfolio Scenarios:

- Scenario # 1 = Current Portfolio with no additional resource procurement
- Scenario #2 = Current Portfolio, with 1 MW purchase of an existing Hydroelectric project
- Scenario #3 = Current Portfolio, with .75 MWs of an existing Hydroelectric project, and 1 MW of On-Shore Wind
- Scenario #4 = Current Portfolio, with .75 MWs of an existing Hydroelectric project, and .5 MW of Off-Shore Wind
- Scenario #5 = Current Portfolio, with 1 MWs of an existing Hydroelectric project, and .5 MW of ISO- New England size Photovoltaic project

The NPV of each scenario Cost and the risk tradeoff is below in Figure 61 . With the stochastic model of @Risk, ENE was able to rank each portfolio by the NPV of each scenario using energy cost and RES value. Using the Monte Carlo simulation allowed ENE the use of multiple variables, such as compliance payment rates, LMP, and load. ENE then performed iterations of these inputs and developed a probability of returns. Next, ENE analyzed these returns to determine the optimal scenario for Hyde Park that would not largely increase costs.

Figure 61: Cost and Risk Tradeoff Bubble Plot



The four primary factors that used for comparative analysis are: (Also found in A.2.3 Resource Alternatives)

1) Least Cost: Mean of the Net Present Value (NPV) of the total portfolio; this includes energy cost of both current resources and potential scenario resources
2) Renewable Energy Standard: Mean of each scenario based on current RES coverage and resources for each scenario.
3) Standard Deviation: Risk of each scenario relative variation of the expected NPV of Total Portfolio Cost and RES, as measured by the standard deviation and various tradeoff considerations
4) Spot Market Exposure: The relative spot market exposure to Hyde Park based on each scenario.

Table 27: Scenario Simulation Summary Statistics by Ranking

	NPV Total Cost	Rank	Total RES	Rank	Std Dev	Rank	Spot Exposure Target Deviation	Rank	Weighting on Cost	Total Rank
Scenario #1	$ 9,460,905	1	$ 721,763	5	$ 2,361,985	5	30%	5	$ 12,544,653	2
Scenario #2	$ 10,745,853	2	$ 603,112	3	$ 1,349,542	4	63%	4	$ 12,207,182	1
Scenario #3	$ 12,571,038	4	$ (191,592)	1	$ 1,137,133	2	70%	3	$ 13,294,747	3
Scenario #4	$ 12,154,095	3	$ 643,413	4	$ 1,165,341	3	70%	2	$ 13,741,016	4
Scenario #5	$ 13,227,764	5	$ 28,897	2	$ 1,042,526	1	73%	1	$ 13,807,863	5

The analytical process was to determine the most optimal scenario for Hyde Park that both, maintained energy costs with reasonable renewable alternatives, and helped curb the large cost impact of RES to HPE. The ranking per category is based solely on the most optimal of that category. ENE chose to consider more than category rank to determine the best solution for Hyde Park. To determine the scenarios that would financial benefit Hyde Park. ENE analyzed how each scenario ranked in each category, the mean cost of each portfolio, and the risk to Hyde Park for each scenario. ENE's integration models were used to run 1,000 iterations of each potential portfolio for energy and 5000 iterations of each potential portfolio for RES impact. ENE determined how the cost, stability, and environmental impact to Hyde Park would be for each scenario. The goal was to manage overall portfolio cost by minimizing the energy cost. Although ENE chose to focus on minimizing the energy cost of the portfolio as the first goal, the next evaluation was the comparative between risk and cost of the portfolio.

I.2 Preferred Plan

I.2.1 Optimal Scenario

The IRP process found the optimal scenario to be scenario #2. This scenario was the current HPE portfolio with an additional 1 MW of an existing hydroelectric project. The projected cost used in ENE's @Risk modeling for a PPA on a small hydro project with Tier I RECs was a $59.30 mWh flat rate. The stochastic model data is below in

Figure 62. The Output for the RES impact is found in Appendix E. The rate used in the scenario can be justified using the PUC's Docket 7874 data updated on 3/6/2015. These rates can be found below in Appendix G. Although this option does not include a lot of diversity in resources, it does bring more diversity to HPE's current portfolio. It adds 30% additional hedging opportunity at a steady price, which can help HPE maintain a rate that does not fluctuate. The largest benefit of a hydro resource like this option provides is a low energy cost due to the type of fuel source. This project would be qualified as Tier I. This scenario helps fill more of HPE's RES requirement in Tier I, which they currently need and will need in the future.

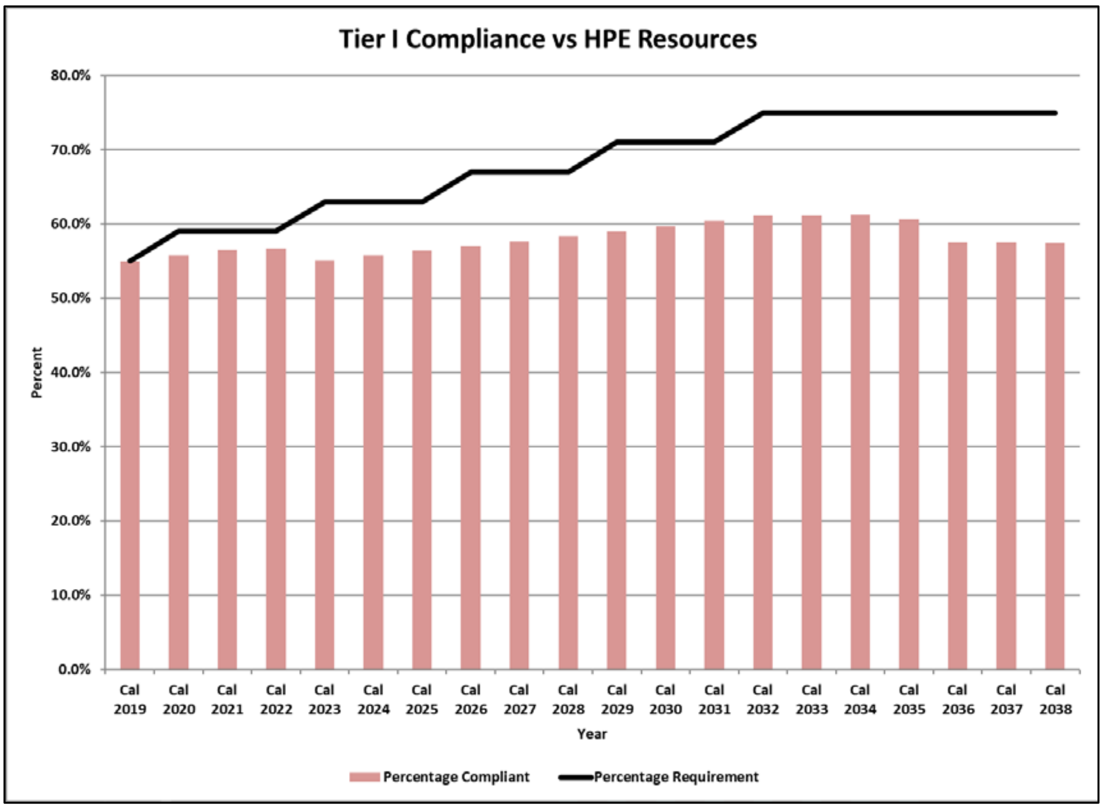
	NPV Total Cost	Rank	Total RES	Rank	Std Dev	Rank	Spot Exposure Target Deviation	Rank	Weighting on Cost	Total Rank
Scenario #2	$ 10,745,853	2	$ 603,112	3	$ 1,349,542	4	63%	4	$ 12,207,182	1

Figure 63 is the resulting coverage of HPE's Tier I RES resulting coverage from scenario #2. This portfolio does not affect HPE's other Tiers.

Figure 62: Optimal Scenario #2

	NPV Total Cost	Rank	Total RES	Rank	Std Dev	Rank	Spot Exposure Target Deviation	Rank	Weighting on Cost	Total Rank
Scenario #2	$ 10,745,853	2	$ 603,112	3	$ 1,349,542	4	63%	4	$ 12,207,182	1

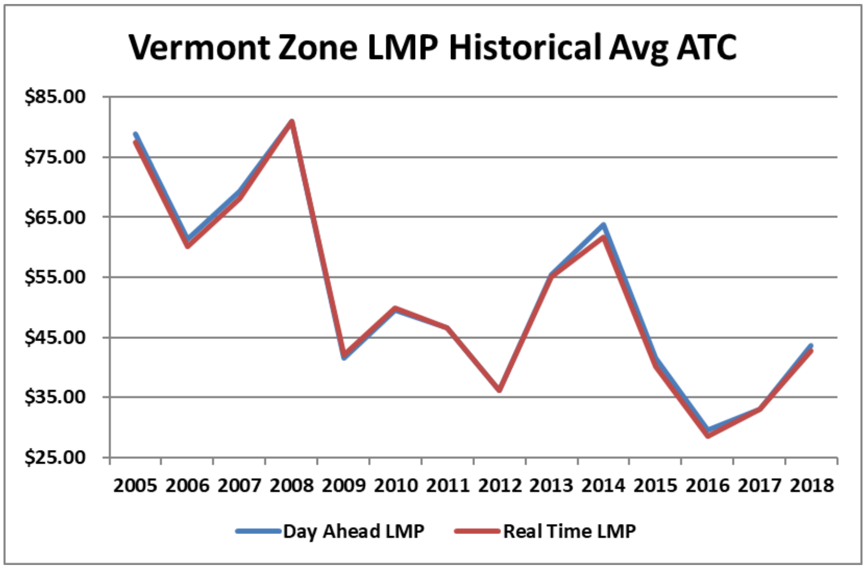
Figure 63: Tier I with Scenario #2



I.2.2 Least Cost Scenario

The least cost scenario is #1. This is actually Hyde Park's current portfolio, with doing no additional hedging or building of renewable projects. The reason for this outcome is largely due to the low forward price curves, seen in Figure 25. The @Risk model is mapping the open position to calculated stochastic forward prices by month, that are reasonably low compared to historical actual prices. The model inputs include Heat Rate and Algonquin City Gate seen in Appendix I. Vermont average LMP for around the clock is below in Figure 64. The current NPV of scenario #1 is low enough to carry the extreme high cost of the NPV of RES to Hyde Park if HPE remains with the current portfolios.

Figure 64: VT LMP Historic Averages of Around the Clock



I.2.3 Greatest Cost Scenario

The greatest cost scenario is #5. This scenario includes the current portfolio with a PPA for .5 MW of a large solar voltaic project, and .75 MW of an existing hydroelectric project. This scenario does not offer HPE much diversity in their power supply. The solar is based at $155.43 MWH [44]. This mirrors the PUC cash flow of solar projects. The Cash Flow model can be found in Appendix J. For the hydro project, with Tier I RECs was a $53.50 MWH flat rate. The rate used in the scenario can be justified using the PUC's Docket 7874 data. These rates can be found below in Appendix G. The cost of new resources, do not offset the RES cost, and therefore, does not make these resources appealing to HPE if it wants to maintain low cost rates for its customers.

I.2.4 Another Optional Scenario

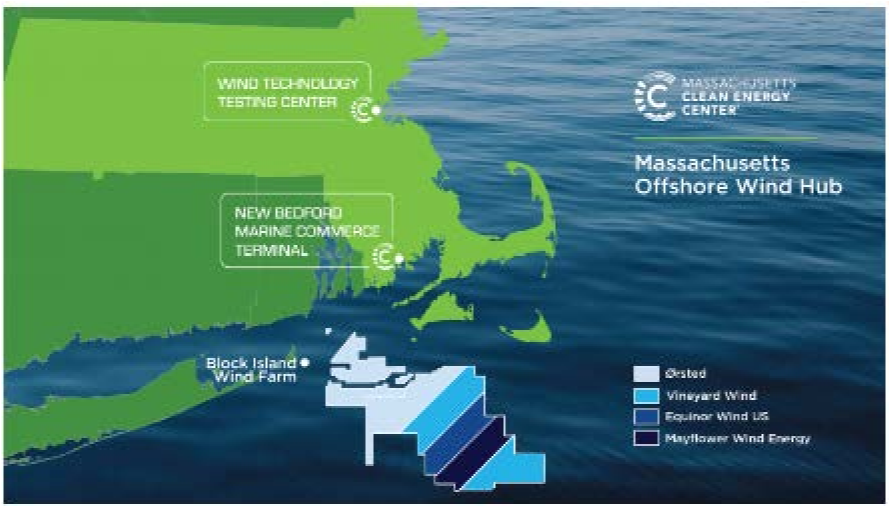
Other scenarios that could benefit HPE is scenario #3. Scenario #3 is HPE's current portfolio with a .75 MW of an existing hydroelectric project, and 1 MW of on shore wind. For the hydro project, with Tier I

[44] http://puc.vermont.gov/document/7874-standard-offer-solar-price-cap-model

RECs was a $53.50 MWH flat rate. The rate used in the scenario can be justified using the PUC's Docket 7874 data. These rates can be found below in Appendix G. The wind project with Class 1 RECs was modeled at $112.54 MWH, which is justified using the PUCs rates found in Appendix F. Because the wind PPA is modeled are more valuable with RECs, HPE has a larger REC arbitrage that helps buy down any RES compliance payments, which makes this scenario appealing.

The last profiled scenario, #4, is similar to #3 but replaces 1 MW of on shore wind with .5 MW of off-shore wind option. "Offshore wind energy generation has a greater capacity factor, approaching 50 percent on an annual basis, than many other renewable energy generators such as solar, especially during winter months." [45] The price modeled comes from the Vineyard Wind PPA[46], found in Appendix H. The less class 1 RECs associated with this portfolio does not offset the HPE's RES compliance cost enough to make this scenario optimal.

Figure 65 Mass CEC Offshore Wind



I.3 Implementation or Action Plan

Based on trade-offs of each scenario, Scenario #2 has the greatest amount of RES benefit and limited energy cost escalation for HPE's Integrated Resource Plan. The components of the optimal and other ideal scenarios are balanced to maintain HPE between 60% to 70% coverage from 2019 through 2038.

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[45] https://www.mass.gov/files/documents/2019/05/31/OSW%20Study%20-%20Final.pdf

[46] https://www.greentechmedia.com/articles/read/first-large-us-offshore-wind-project-sets-record-low-price-starting-at-74#gs.osp0vx

This target is HPE's risk tolerance, because the municipal knows if market prices increase high enough the open position is subject to more risk. This scenario allows HPE to add other potential types of resources to a portfolio that is already RES compliant and is economically reasonable. Vermont based resources will be the most sought after. HPE is currently seeking counterparties for bilateral transactions. Because HPE does not have any Master Agreements, counterparties are requiring more information before transactions can take place. HPE will also analysis the capacity benefits of any potential transaction. HPE will evaluate each potential resource on cost and benefit to both energy and RES. After 2038, depending on both the energy and renewable markets, HPE will have another option window to look into for additional products in order to comply with any new regulations. Reviewing Vermont based resources will be the key to HPEs RES compliance and reducing their environmental impact. This option reduces environmental carbon footprint for Vermont and HPE's customers. It would provide a long-term energy price point that HPE can lock into its rates so it can monitor rate increases more efficiently if needed. Lastly, it will provide HPE a RES compliance that will reduce its exposure to any compliance payments, which could increase costs to the ratepayers. HPE does plan on purchasing any short position on their RES compliance with RECs.

I.4 Ongoing Maintenance and Evaluation

Hyde Park will update this IRP on a scheduled basis per regulatory requirement and make any necessary adjustments. The implementation of the plan will include an annual review of factors that could initiate an adjustment, such as major shifts in the New England supply stack, new generation and carbon capture technology, fundamental changes to the natural gas market, and regulatory changes, including ISO New England market design.

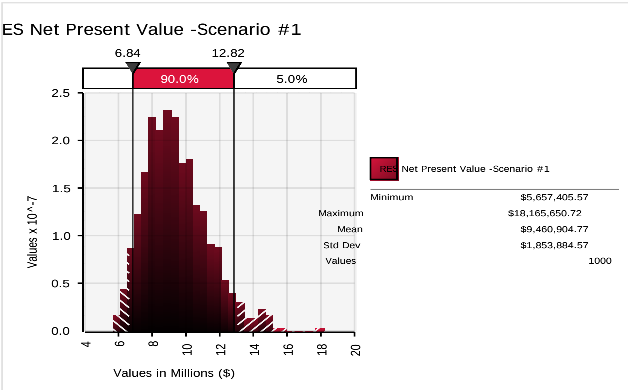
In the next IRP, Hyde Park will use the recommendations in the Vermont CEP and guidance from the Department of Public Service when addressing and setting a path to helping Vermont meet its goals. V.S.A. § 8001 states the RES program is to promote renewable energy goals of "Balancing the benefits, lifetime costs, and rates of the State's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the State flow to the Vermont economy in general, and to the rate-paying citizens of the State in particular".[47]

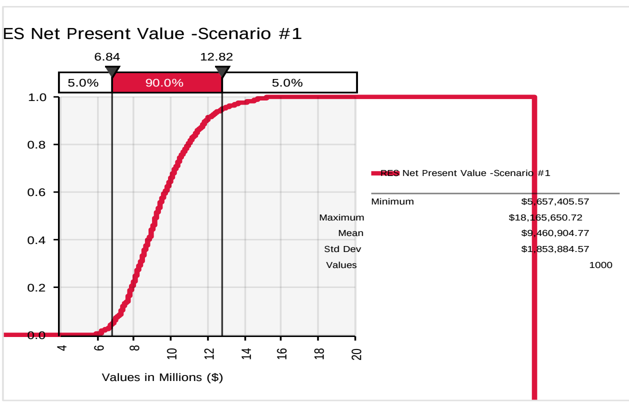
[47] http://legislature.vermont.gov/statutes/section/30/089/08001

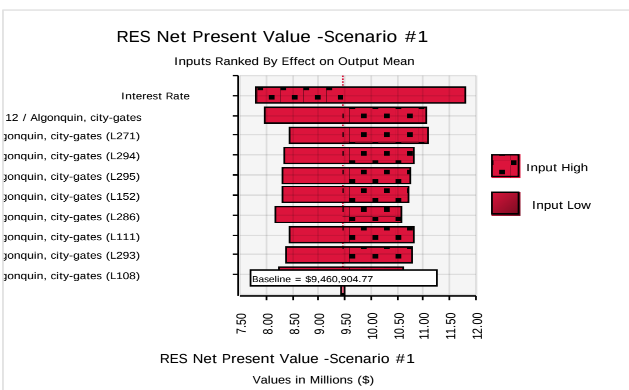
A Appendix A

Model Results

@RISK Output Report for Net Present Value -Scenario #1 B26







Simulation Summary Information	
Workbook Name	Position Cal-HPE Model#1.xlsm
Number of Simulations	1
Number of Iterations	1000
Number of Inputs	709
Number of Outputs	107
Sampling Type	Latin Hypercube
Simulation Start Time	6/25/2019 17:05
Simulation Duration	00:01:39
Random # Generator	Mersenne Twister
Random Seed	1

Summary Statistics for RES Net Present Value -Scenari			
Statistics		**Percentile**	
Minimum	$ 5,657,406	5%	$ 6,840,761
Maximum	$ 18,165,651	10%	$ 7,307,635
Mean	$ 9,460,905	15%	$ 7,650,973
Std Dev	$ 1,853,885	20%	$ 7,881,036
Variance	3.43689E+12	25%	$ 8,108,128
Skewness	0.726749857	30%	$ 8,338,179
Kurtosis	3.644313849	35%	$ 8,566,401
Median	$ 9,192,802	40%	$ 8,767,756
Mode	$ 8,199,604	45%	$ 9,008,724
Left X	$ 6,840,761	50%	$ 9,192,802
Left P	5%	55%	$ 9,415,976
Right X	$ 12,815,817	60%	$ 9,715,147
Right P	95%	65%	$ 9,970,790
Diff X	$ 5,975,056	70%	$ 10,269,980
Diff P	90%	75%	$ 10,538,699
#Errors	0	80%	$ 10,940,145
Filter Min	Off	85%	$ 11,405,127
Filter Max	Off	90%	$ 11,925,261
#Filtered	0	95%	$ 12,815,817

Change in Output Statistic for RES Net Present Value -			
Rank	**Name**	**Lower**	**Upper**
1	Interest Rate	$ 7,797,636	$ 11,805,214
2	12 / Algonquin, ci	$ 7,969,823	$ 11,039,445
3	Algonquin, city-ga	$ 8,453,994	$ 11,092,559
4	Algonquin, city-ga	$ 8,359,541	$ 10,824,822
5	Algonquin, city-ga	$ 8,326,731	$ 10,751,911
6	Algonquin, city-ga	$ 8,308,856	$ 10,716,678
7	Algonquin, city-ga	$ 8,190,083	$ 10,591,785
8	Algonquin, city-ga	$ 8,431,332	$ 10,830,993
9	Algonquin, city-ga	$ 8,390,934	$ 10,789,152
10	Algonquin, city-ga	$ 8,239,949	$ 10,626,456

B Appendix B

STANDARD OFFER PROJECTS OPERATING as of April 24, 2019. Total MW of 134,439

Standard Offer Projects Operating

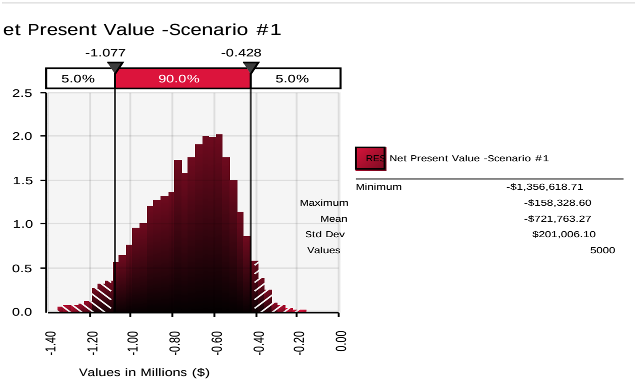
Total Estimated Annual Output = 134,439 MW

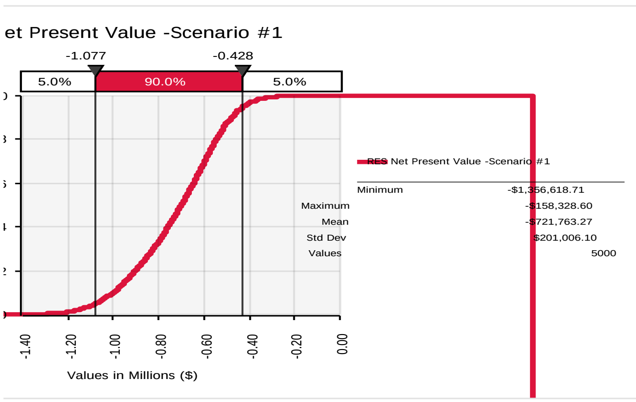
PROJECT NAME	PROJECT FUEL	ESTIMATED ANNUAL OUTPUT MW
Audet's Cow Power	Farm Methane	4,557
Berkshire Cow Power	Farm Methane	4,021
Chaput Family Farms	Farm Methane	2,010
Dubois Energy	Farm Methane	3,016
Four Hills Farms	Farm Methane	3,016
Gervais Digester	Farm Methane	1,340
Gervais Digester 2	Farm Methane	1,340
Green Mountain Dairy	Farm Methane	2,010
Green Mountain Dairy 2	Farm Methane	2,010
Kanes Cow Power	Farm Methane	1,508
Maplehurst Farms	Farm Methane	1,005
Neighborhood Energy	Farm Methane	1,508
Rail City Cow Power	Farm Methane	2,010
Riverview Farms	Farm Methane	1,267
Westminster Energy	Farm Methane	3,016
Vermont Technical College	Farm Methane	2,513
Advanced Transit	Solar	41
Barton Solar Farm	Solar	2,401
Bobbin Mill	Solar	64
Bridport West Solar Farm	Solar	2,540
Butternut Farm Solar	Solar	131
Champlain Valley Solar Farm	Solar	2,540
Charlotte Solar	Solar	2,540
Chester Solar	Solar	2,540
Claire Solar	Solar	2,794
Clarendon Solar	Solar	2,540
Clarke Solar Center, LLC	Solar	1,016
Coventry Solar	Solar	2,794
Cross Pollination One	Solar	2,540
Ferrisburgh Solar Farm	Solar	1,330
IRA Rentals Solar	Solar	47
Kingsbury Solar	Solar	61
Launig's Building	Solar	33
Limerick Solar	Solar	2,751
Lyndonville Solar West (1)	Solar	610
Lyndonville Solar East (2)	Solar	629
MartinBrookPV Solar	Solar	1,905
Next Generation Solar Farm	Solar	2,794
Northshire	Solar	20
Otter Valley Solar	Solar	2,769
Pownal Park Solar	Solar	2,794
Sheldon Springs Solar	Solar	2,794
South Burlington Solar	Solar	2,802
Southern VT Energy Park	Solar	2,540
Springfield Solar Alliance	Solar	1,270
St. Albans Solar Farm	Solar	2,540
Sudbury Solar	Solar	2,540
SunGen1 Solar	Solar	2,667
Technology Drive Solar	Solar	2,540
Whitcomb Farm	Solar	2,794
White River Junction	Solar	2,751
Williamstown	Solar	2,540
Ball Mountain Hydro	Hydroelectric	8,653
Factory Falls	Hydroelectric	590
North Hartland	Hydroelectric	543
Townshend Hydro	Hydroelectric	3,776
Troy Hydro Project	Hydroelectric	3,210
West Charleston	Hydroelectric	2,655
Carsosimo Lumber Biomass	Biomass	6,441
BCH Landfill Gas to Energy	Landfill Methane	4,415
TOTAL		134,439

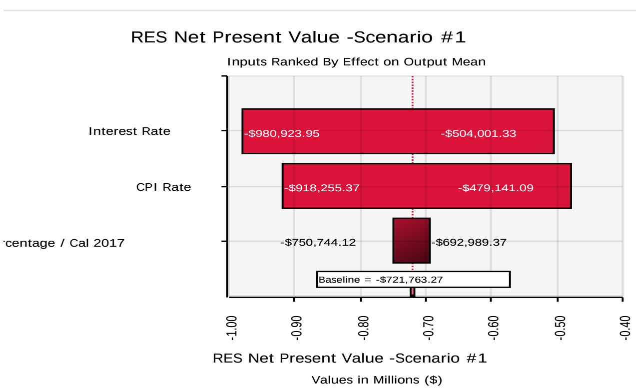
C Appendix C

RES Analysis Base Case

@RISK Output Report for RES Net Present Value -Scenario #1 B88







Simulation Summary Information	
Workbook Name	RES #1.xlsx
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	3
Number of Outputs	21
Sampling Type	Latin Hypercube
Simulation Start Time	6/18/2019 11:55
Simulation Duration	00:00:05
Random # Generator	Mersenne Twister
Random Seed	1

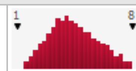
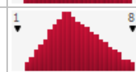
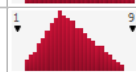
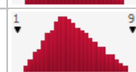
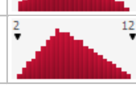
Summary Statistics for RES Net Present Value -Sce			
Statistics		**Percentile**	
Minimum	($1,356,619)	5%	############
Maximum	($158,329)	10%	($998,846)
Mean	($721,763)	15%	($946,930)
Std Dev	$201,006	20%	($903,647)
Variance	40403453881	25%	($862,296)
Skewness	-0.362176802	30%	($824,129)
Kurtosis	2.690643574	35%	($788,196)
Median	($698,565)	40%	($758,716)
Mode	($670,469)	45%	($728,701)
Left X	($1,076,644)	50%	($698,565)
Left P	5%	55%	($672,416)
Right X	($427,818)	60%	($646,326)
Right P	95%	65%	($621,338)
Diff X	$648,826	70%	($596,168)
Diff P	90%	75%	($571,792)
#Errors	0	80%	($545,610)
Filter Min	Off	85%	($515,477)
Filter Max	Off	90%	($476,935)
#Filtered	0	95%	($427,818)

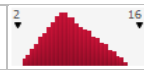
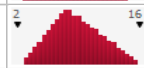
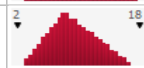
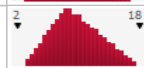
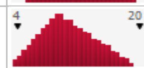
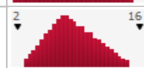
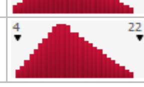
Change in Output Statistic for RES Net Present Va			
Rank	**Name**	**Lower**	**Upper**
1	Interest Rate	($980,924)	($504,001)
2	CPI Rate	($918,255)	($479,141)
3	REC Percentage /	($750,744)	($692,989)

D Appendix D

Capacity Simulation for Alternative Simulation based on historical year weighing

@RISK Output Results

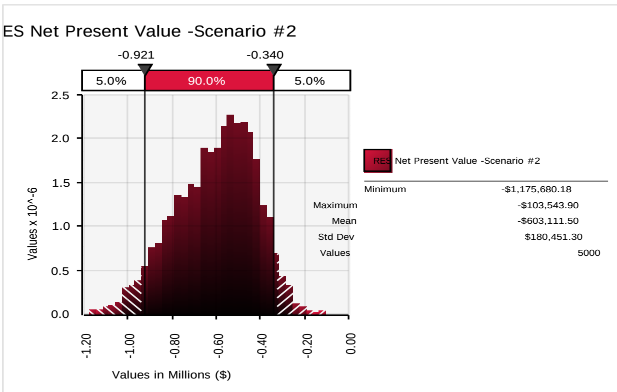
Name	Worksheet	Cell	Graph	Min	Mean	Max	5%	95%
Range: FCM Prices								
FCM Prices / 2024	FCM	I18		1.706	4.492	7.775	2.405	6.821
FCM Prices / 2025	FCM	J18		1.742	4.605	7.957	2.490	7.009
FCM Prices / 2026	FCM	K18		1.818	4.720	8.275	2.538	7.194
FCM Prices / 2027	FCM	L18		1.763	4.838	8.447	2.593	7.374
FCM Prices / 2028	FCM	M18		1.873	4.959	8.520	2.660	7.549
FCM Prices / 2029	FCM	N18		1.997	5.083	8.779	2.727	7.739
FCM Prices / 2030	FCM	O18		1.915	5.210	9.028	2.799	7.919
FCM Prices / 2031	FCM	P18		2.032	5.339	9.167	2.881	8.141
FCM Prices / 2032	FCM	Q18		2.032	5.473	9.443	2.946	8.318
FCM Prices / 2033	FCM	R18		2.210	5.611	9.658	3.017	8.529
FCM Prices / 2034	FCM	S18		2.167	5.751	9.911	3.109	8.775
FCM Prices / 2035	FCM	T18		2.279	5.894	10.302	3.165	8.947
FCM Prices / 2036	FCM	U18		2.379	6.042	10.492	3.249	9.196
FCM Prices / 2037	FCM	V18		2.317	6.192	10.648	3.333	9.411
FCM Prices / 2038	FCM	W18		2.444	6.348	11.107	3.411	9.676
FCM Prices / 2039	FCM	X18		2.486	6.506	11.454	3.489	9.875
FCM Prices / 2040	FCM	Y18		2.431	6.668	11.601	3.574	10.146

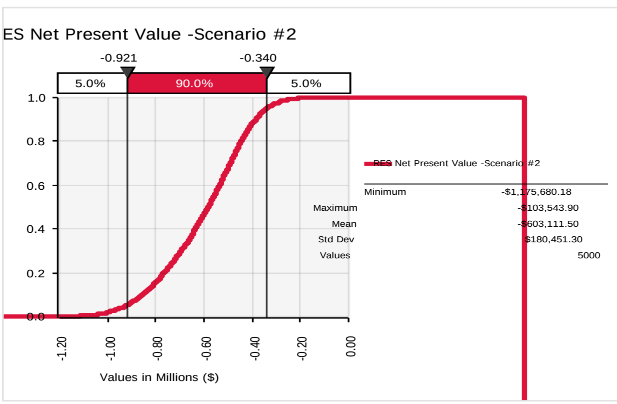
	FCM Prices / 2033	T18	1		3.121	8.272	14.401	4.491	12.528
	FCM Prices / 2033	T18	2		3.344	8.864	15.432	4.812	13.425
	FCM Prices / 2033	T18	3		3.567	9.456	16.462	5.133	14.321
	FCM Prices / 2033	T18	4		3.716	9.850	17.149	5.347	14.918
	FCM Prices / 2033	T18	5		4.088	10.836	18.866	5.883	16.412
	FCM Prices / 2034	U18	1		3.290	8.478	14.556	4.623	12.809
	FCM Prices / 2034	U18	2		3.525	9.084	15.597	4.953	13.725
	FCM Prices / 2034	U18	3		3.760	9.691	16.639	5.284	14.642
	FCM Prices / 2034	U18	4		3.917	10.095	17.333	5.505	15.253
	FCM Prices / 2034	U18	5		4.309	11.106	19.069	6.056	16.780
	FCM Prices / 2035	V18	1		3.212	8.690	14.940	4.724	13.125
	FCM Prices / 2035	V18	2		3.441	9.312	16.009	5.062	14.064
	FCM Prices / 2035	V18	3		3.671	9.933	17.078	5.400	15.003
	FCM Prices / 2035	V18	4		3.824	10.348	17.790	5.625	15.629
	FCM Prices / 2035	V18	5		4.207	11.384	19.572	6.189	17.194
	FCM Prices / 2036	W18	1		3.329	8.907	15.373	4.857	13.492
	FCM Prices / 2036	W18	2		3.568	9.545	16.472	5.204	14.457
	FCM Prices / 2036	W18	3		3.806	10.182	17.572	5.551	15.423
	FCM Prices / 2036	W18	4		3.965	10.607	18.305	5.783	16.066
	FCM Prices / 2036	W18	5		4.362	11.669	20.138	6.362	17.675
	FCM Prices / 2037	X18	1		3.494	9.129	15.796	4.979	13.789
	FCM Prices / 2037	X18	2		3.744	9.783	16.926	5.335	14.776
	FCM Prices / 2037	X18	3		3.994	10.436	18.056	5.692	15.762
	FCM Prices / 2037	X18	4		4.161	10.871	18.810	5.929	16.420
	FCM Prices / 2037	X18	5		4.577	11.960	20.693	6.523	18.064

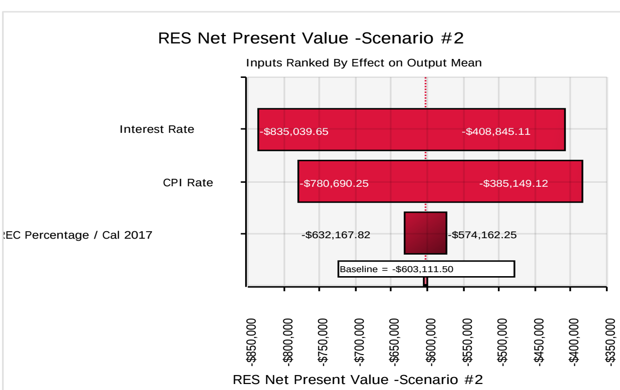
E Appendix E

RES Analysis on most optimal case

@RISK Output Report for RES Net Present Value -Scenario #2 B88







Simulation Summary Information	
Workbook Name	RES #2.xlsx
Number of Simulations	1
Number of Iterations	5000
Number of Inputs	3
Number of Outputs	21
Sampling Type	Latin Hypercube
Simulation Start Time	7/12/2019 16:45
Simulation Duration	00:00:11
Random # Generator	Mersenne Twister
Random Seed	1

Summary Statistics for RES Net Present Value -Sce			
Statistics		**Percentile**	
Minimum	($1,175,680)	**5%**	($920,965)
Maximum	($103,544)	**10%**	($851,583)
Mean	($603,112)	**15%**	($805,074)
Std Dev	$180,451	**20%**	($766,240)
Variance	32562672171	**25%**	($728,056)
Skewness	-0.373670707	**30%**	($694,229)
Kurtosis	2.704532194	**35%**	($661,771)
Median	($582,505)	**40%**	($636,182)
Mode	($560,803)	**45%**	($608,622)
Left X	($920,965)	**50%**	($582,505)
Left P	5%	**55%**	($559,119)
Right X	($339,741)	**60%**	($534,807)
Right P	95%	**65%**	($513,257)
Diff X	$581,224	**70%**	($490,782)
Diff P	90%	**75%**	($468,566)
#Errors	0	**80%**	($445,399)
Filter Min	Off	**85%**	($418,058)
Filter Max	Off	**90%**	($384,145)
#Filtered	0	**95%**	($339,741)

Change in Output Statistic for RES Net Present Va			
Rank	**Name**	**Lower**	**Upper**
1	Interest Rate	($835,040)	($408,845)
2	CPI Rate	($780,690)	($385,149)
3	REC Percentage /	($632,168)	($574,162)

F Appendix F

Wind Pricing Model

Assumptions:			Notes:
General Inflation Factor (revenue and expenses)	1.60%		
% of Base Price Escalating @ Infl.	30%		
Uses of Funds			
Debt Reserve	0		
Maint. Reserve	0		
Working Capital	26,060		3 months
Total Working Capital & Reverses	26,060		
			(5%/12 months *
Financing Costs & IDC	37,500		Installation Costs *
Installation Cost (Hard Costs)	4,500,000		
Total Uses of Funds	4,563,560		
Total Project Cost ($/kW)	3,042		
Sources of Funds			
Grants	0		
Debt	1,825,424		
Equity	2,738,136		
Total Sources of Funds	4,563,560		
Grants:			
State and Federal Incentives	0		
Net Value of Grants	0		
Asset Life (Years)	25		
Loan Life	18		
Tax Rates:			
Federal Income Tax	35.0%		
State Income Tax	8.5%		
Income tax rate	40.53%		
Capital structure:			
Debt	40.00%		
Equity	60.00%		
Debt costs	7.25%		
Weighted Average Cost of Capital	8.75%	9.75%	
Tax Rates and Incentives:			
Investment Tax Credit Discount (% of Hard Costs)	95.0%		
Income Tax Basis Adjustment Factor	50.0%		
Federal Income Tax Credit			
ITC Rate	30.0%		
ITC Realization Period (years)	1		
ITC Amount			
Total Amount	1,282,500		
Percent Realized	100.0%		
Total Amount Realized	1,282,500		
State Income Tax Credit			
ITC Rate			
Amount of Federal ITC Allowed	24.00%		
Effective State ITC Rate	7.20%		
ITC Realization Period (years)	1		
ITC Amount			
Total Amount	200,070		
Percent Realized	50.0%		
Total Amount Realized	100,035		

Assumptions:		Notes:
Operating Inputs:		
Generator Capacity (MW)	1.5	
Energy Production:		
Gross Project Capacity Factor	25.8%	
Project Availability Factor	100.00%	
Loss Factor/Other Adjustments	0.00%	
Net Capacity Factor	25.8%	
Output in MWhs	3,390	
Annual Output Degradation	0.00%	
Inverter Replacement (total value year 10)	0	
Annual Operating Expenses:		
Maintenance Cost	See Schedule Below	
Labor		
Hours of Labor	0	
Labor Rate ($/hour)	0	
Payroll Overhead Adder	0.0%	
Property Tax		
Amount	EBITDA x WACC x Tax Rate	
Property Tax Rate	1.78%	
Property Tax Depreciation rate	4.00%	
Insurance	0.40%	
Other Operational Expenses (lease)	4,500	
Wheeling Charges	0	
FERC Charges	0	
ISO-NE Charges	0	
Revenue Assumptions:		
RECs:		
REC and Carbon Value ($/MWh)	0.00	
REC inflation Factor	2.00%	
Other Revenues (increases with inflation)	0	
Base Year Energy Price ($/MWh)	112.54	
Return Metrics:		
Average Debt Service Coverage Ratio	1.57	
Minimum Debt Service Coverage Ratio	1.50	
Internal Rate of Return	9.75%	
Maintenance Schedule		
Year 1 (escalates at inflation)	49,080	69000

G Appendix G[48]

2015 Price Elements for Existing Hydroelectric Plants				
	10-Year Contract LIHI certified	10-Year Contract	20-Year Contract LIHI certified	20-Year Contract
Energy	5.83 cents/kWh	5.83 cents/kWh	5.83 cents/kWh	5.83 cents/kWh
Capacity	TBD	TBD	TBD	TBD
Avoided Line Losses	3% or 5%	3% or 5%	3% or 5%	3% or 5%
Environmental Attributes	2.3 cents/kWh	0.1 cents/kWh	2.6 cents/kWh	0.1 cents/kWh
Contract Adder Value	5%	5%	10%	10%
Note: The capacity price element for each hydroelectric unit shall be calculated by multiplying the ISO-NE capacity rating by the FCM payment price and dividing that revenue value by the kWh the plant generates. The capacity rating for an ISO-SOG is the FCM-qualified winter and summer capacity rating. The capacity rating for a load-reducer is its generation at the time of the ISO-NE peak for the previous two years. The FCM payment price for use in 2015 contracts is $2.69 per kW-month. For load reducers a 15 percent adder shall be made to the capacity revenue value.				

48 https://puc.vermont.gov/sites/psbnew/files/doc_library/standard-offer-7874-final-order-hydro-pricing.pdf

H Appendix H[49]

Off Shore Wind, Average cost of $98.00 of the 20-year Purchase Power Agreement.

Vineyard Wind Phase 1 Product Price

(a) Product Price –Commencing on the Commercial Operation Date, the Price per MWH for the Products shall be as follows.

The Price per MWh for each billing period shall be as follows: Year		Price ($/MWh)
1		74.00
2		75.85
3		77.75
4		79.69
5		81.68
6		83.72
7		85.82
8		87.96
9		90.16
10		92.42
11		94.73
12		97.09
13		99.52
14		102.01
15		104.56
16		107.17
17		109.85
18		112.60
19		115.41
20		118.30

[49] https://www.greentechmedia.com/articles/read/first-large-us-offshore-wind-project-sets-record-low-price-starting-at-74#gs.osp0vx

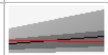
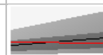
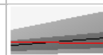
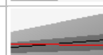
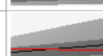
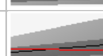
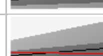
I Appendix I

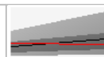
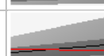
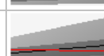
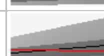
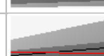
Heat Rate and Algonquin Inputs

@RISK Model Inputs

Name	Worksheet	Cell	Graph	Function	Min	Mean	Max
Category: <none>							
5x16 Heat Rate-1	HR & LMP	AR5		RiskTriang(AR2,AR3,AR4,RiskName("5x16 Heat Rate-1"))	6.7155	11.5529	19.11417
2x16 Heat Rate-1	HR & LMP	AR11		RiskTriang(AR8,AR9,AR10,RiskName("2x16 Heat Rate-1"))	5.2965	10.4767	17.91317
7x8 Heat Rate-1	HR & LMP	AR17		RiskTriang(AR14,AR15,AR16,RiskName("7x8 Heat Rate-1"))	5.2594	9.2578	15.51083
5x16 Heat Rate-2	HR & LMP	AS5		RiskTriang(AS2,AS3,AS4,RiskName("5x16 Heat Rate-2"))	6.8471	9.4870	12.55218
2x16 Heat Rate-2	HR & LMP	AS11		RiskTriang(AS8,AS9,AS10,RiskName("2x16 Heat Rate-2"))	4.1295	8.0621	11.66253
7x8 Heat Rate-2	HR & LMP	AS17		RiskTriang(AS14,AS15,AS16,RiskName("7x8 Heat Rate-2"))	5.2747	7.4061	9.882911
5x16 Heat Rate-3	HR & LMP	AT5		RiskTriang(AT2,AT3,AT4,RiskName("5x16 Heat Rate-3"))	8.1640	10.0805	12.25572
2x16 Heat Rate-3	HR & LMP	AT11		RiskTriang(AT8,AT9,AT10,RiskName("2x16 Heat Rate-3"))	4.2324	8.1635	11.26896
7x8 Heat Rate-3	HR & LMP	AT17		RiskTriang(AT14,AT15,AT16,RiskName("7x8 Heat Rate-3"))	5.9810	7.5332	9.295308
5x16 Heat Rate-4	HR & LMP	AU5		RiskTriang(AU2,AU3,AU4,RiskName("5x16 Heat Rate-4"))	8.2707	10.5022	13.27554
2x16 Heat Rate-4	HR & LMP	AU11		RiskTriang(AU8,AU9,AU10,RiskName("2x16 Heat Rate-4"))	4.2685	8.6417	12.40801
7x8 Heat Rate-4	HR & LMP	AU17		RiskTriang(AU14,AU15,AU16,RiskName("7x8 Heat Rate-4"))	6.3743	8.2904	10.67294
5x16 Heat Rate-5	HR & LMP	AV5		RiskTriang(AV2,AV3,AV4,RiskName("5x16 Heat Rate-5"))	10.5803	11.1041	11.65667
2x16 Heat Rate-5	HR & LMP	AV11		RiskTriang(AV8,AV9,AV10,RiskName("2x16 Heat Rate-5"))	3.2678	7.8212	10.35553
7x8 Heat Rate-5	HR & LMP	AV17		RiskTriang(AV14,AV15,AV16,RiskName("7x8 Heat Rate-5"))	7.0421	7.3887	7.754247
5x16 Heat Rate-6	HR & LMP	AW5		RiskTriang(AW2,AW3,AW4,RiskName("5x16 Heat Rate-6"))	10.6662	11.5928	12.44676
2x16 Heat Rate-6	HR & LMP	AW11		RiskTriang(AW8,AW9,AW10,RiskName("2x16 Heat Rate-6"))	4.0843	8.4187	10.93301
7x8 Heat Rate-6	HR & LMP	AW17		RiskTriang(AW14,AW15,AW16,RiskName("7x8 Heat Rate-6"))	6.7205	7.3372	7.905319
5x16 Heat Rate-7	HR & LMP	AX5		RiskTriang(AX2,AX3,AX4,RiskName("5x16 Heat Rate-7"))	12.1484	13.1183	13.93745
2x16 Heat Rate-7	HR & LMP	AX11		RiskTriang(AX8,AX9,AX10,RiskName("2x16 Heat Rate-7"))	3.8034	8.9516	11.81355
7x8 Heat Rate-7	HR & LMP	AX17		RiskTriang(AX14,AX15,AX16,RiskName("7x8 Heat Rate-7"))	6.5145	7.0855	7.566297
5x16 Heat Rate-8	HR & LMP	AY5		RiskTriang(AY2,AY3,AY4,RiskName("5x16 Heat Rate-8"))	12.2869	13.4407	14.47071
2x16 Heat Rate-8	HR & LMP	AY11		RiskTriang(AY8,AY9,AY10,RiskName("2x16 Heat Rate-8"))	3.5838	9.1284	12.28584
7x8 Heat Rate-8	HR & LMP	AY17		RiskTriang(AY14,AY15,AY16,RiskName("7x8 Heat Rate-8"))	6.7149	7.3495	7.915684
5x16 Heat Rate-9	HR & LMP	AZ5		RiskTriang(AZ2,AZ3,AZ4,RiskName("5x16 Heat Rate-9"))	12.9347	13.7618	14.55005
2x16 Heat Rate-9	HR & LMP	AZ11		RiskTriang(AZ8,AZ9,AZ10,RiskName("2x16 Heat Rate-9"))	4.3880	9.6112	12.55332
7x8 Heat Rate-9	HR & LMP	AZ17		RiskTriang(AZ14,AZ15,AZ16,RiskName("7x8 Heat Rate-9"))	7.5145	8.0497	8.559265
5x16 Heat Rate-10	HR & LMP	BA5		RiskTriang(BA2,BA3,BA4,RiskName("5x16 Heat Rate-10"))	10.9550	11.9838	13.01923
2x16 Heat Rate-10	HR & LMP	BA11		RiskTriang(BA8,BA9,BA10,RiskName("2x16 Heat Rate-10"))	3.4340	8.6108	11.68029
7x8 Heat Rate-10	HR & LMP	BA17		RiskTriang(BA14,BA15,BA16,RiskName("7x8 Heat Rate-10"))	7.4098	8.2039	9.00194
5x16 Heat Rate-11	HR & LMP	BB5		RiskTriang(BB2,BB3,BB4,RiskName("5x16 Heat Rate-11"))	8.2526	10.9610	14.49555
2x16 Heat Rate-11	HR & LMP	BB11		RiskTriang(BB8,BB9,BB10,RiskName("2x16 Heat Rate-11"))	4.5280	8.9929	13.21341
7x8 Heat Rate-11	HR & LMP	BB17		RiskTriang(BB14,BB15,BB16,RiskName("7x8 Heat Rate-11"))	6.0585	8.0498	10.64834
5x16 Heat Rate-12	HR & LMP	BC5		RiskTriang(BC2,BC3,BC4,RiskName("5x16 Heat Rate-12"))	5.5919	7.6050	9.819442
2x16 Heat Rate-12	HR & LMP	BC11		RiskTriang(BC8,BC9,BC10,RiskName("2x16 Heat Rate-12"))	2.1211	6.0521	9.140181
7x8 Heat Rate-12	HR & LMP	BC17		RiskTriang(BC14,BC15,BC16,RiskName("7x8 Heat Rate-12"))	4.4506	6.0367	7.781323

@RISK Model Inputs

Name	Worksheet	Cell	Graph	Function	Min	Mean	Max
Category: Time Series - Algonquin, city-gates (L51:L107)							
Algonquin, city-gates	AGT and HH	L51		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L52		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L53		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L54		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L55		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L56		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L57		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L58		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L59		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L60		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L61		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L62		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L63		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L64		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L65		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L66		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L67		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L68		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L69		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L70		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L71		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L72		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L73		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L74		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L75		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L76		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L77		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L78		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L79		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
Algonquin, city-gates	AGT and HH	L80		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538

	Algonquin, city-gates	AGT and HH	L81		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L82		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L83		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L84		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L85		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L86		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L87		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L88		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L89		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L90		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L91		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L92		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L93		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L94		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L95		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L96		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L97		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L98		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L99		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L100		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L101		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L102		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L103		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L104		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L105		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L106		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538
	Algonquin, city-gates	AGT and HH	L107		RiskMA2(1.3058,0.49498,0.67544,-0.087444,-0.3547,0.78055,RiskTsTransform(1,0),RiskTsSync(2,'AGT and	-∞	4.178877	29.06538

J Appendix J

Solar Pricing Model

Assumptions:			**Notes:**
			From http://www.clevelandfed.org/research/data/inflation_expectations/
General Inflation Factor	1.89%		
% of Base Price Escalati	0%		
Uses of Funds			
Debt Reserve	73,800		($73,739)
Maint. Reserve	0		$60.00
Decommissioning Fund	0		$60/kW avg decommissioning costs from Dockets 8302, 8248, 8234, 8225
Working Capital	41,063		6 months of working capital
Total Working Capital &	114,863		
Financing Costs & IDC	362,925		3% of approximate debt amount (E17) + (5%/12 months * Installation Costs * 4.5 months = IDC) + $ (E18) for Tax equity
Installation Cost (Hard	5,500,000		$2.50
Total Uses of Funds	5,977,788		Insall cost per watt from recent docket
Total Project Cost ($/kW	2,717		
Sources of Funds			
Grants	0		
Debt	3,586,673		$3,660,000
Equity	2,391,115		$150,000
Total Sources of Funds	5,977,788		
Grants:			
State and Federal Ince	0		
Net Value of Grants	0		
Asset Life (Years)	25		
Loan Lif Long Term Loan	18		
Short-Term Loa	6		
Tax Rates:			
Federal Income Tax	35.0%		
State Income Tax	8.5%		
Income tax rate	40.53%		
Capital structure:			
Debt Long Term Loan	30.00%		
Debt Short-Term Loa	30.00%		
Equity	40.00%		
Debt costs: Long Terr	4.50%		
Debt costs: Short Ter	3.00%		
Weighted Average Cc	6.09%	9.60%	
Tax Rates and Incentives:			
Investment Tax Credi	97.5%		
Income Tax Basis Adj	50.0%		
Federal Income Tax Credit			
ITC Rate	30.0%		
ITC Realization Pe	1		
ITC Amount			
Total Amount	1,608,750		Federal ITC Value Loss
Percent Realize	100.0%		0
Total Amount F	1,608,750		
State Income Tax Credit			
ITC Rate			
Amount of Fed	24.00%		
Effective State	7.20%		
ITC Realization Pe	1		
ITC Amount			
Total Amount	250,965		State ITC Value Loss
Percent Realize	100.0%		0
Total Amount F	250,965		

Assumptions:		**Notes:**
Operating Inputs:		
Generator Capacity (MW)	2.2	
Energy Production:		
Gross Project Capacity Factor	14.50%	
Project Availability Factor	100.00%	
Loss Factor/Other Adjustments	0.00%	
Net Capacity Factor	14.5%	
Output in MWhs	2,794	
Annual Output Degradation	0.50%	
Inverter Replacement		per watt cost inflated from p.10 conservative estimate using commercial scale system http://www1.eere.energy.gov/solar/pdfs/47927_chapter4.pdf, plus $3000 labor
Value Year 12	400,000	0.2
Annual Operating Expenses:		
Maintenance Cost	25,528	$6.67/kW
Labor		
Hours of Labor	0	
Labor Rate ($/hour)	0	
Payroll Overhead Adder	0.0%	
Property Tax		
Amount	EBITDA x WACC x Tax Rate	
Property Tax Rate	0.56%	Tax Rate approximately $12/watt.
		14
Depreciation Rate	4.00%	
Insurance (% of Installation Cost)	0.40%	
Other Operational Expenses	0	6.8
Lease	14,960	1000
FERC Charges	0	lease acres X price per X plant size
ISO-NE Charges	0	
Revenue Assumptions:		
RECs:		
REC and Carbon Value ($/MWh)	0.00	
REC inflation Factor	2.00%	
Other Revenues (increases with inflatio	0	
Base Year Energy Price ($/MWh)	155.43	
Return Metrics:		
Average Debt Service Coverage Ratio	1.95	
Minimum Debt Service Coverage Ratio	1.79	
Internal Rate of Return	9.60%	

K Appendix K

Inverter Source Requirements

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

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

be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter

have the voltage and frequency trip settings

have the abnormal performance capabilities (ride-through)

comply with other grid support utility interactive inverter functions statuses

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

Certification per UL 1741 SA as grid support utility interactive inverters

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

shall be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std 1547-2018 (2nd ed.)1 that can be certified per the type test requirements of

UL 1741 SA (September 2016). IEEE Std 1547-2018 (2nd ed.) in combination with this document replaces other Source Requirements Documents (SRDs), as applicable;

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

Voltage and frequency trip settings for inverter based applications

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

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

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

The following additional performance requirements hall apply for all inverters:

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

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

17.3 as a proxy, subject to mioreditorial changes.

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

DER tripping requirements specified in this SRD shall take precedence over the abnormal performance capability (ride-through) requirements in this section, subject to the following:

Where the prescribed trip duration settings for the respective voltage or frequency magnitude are set at least 160 ms or 1% of the prescribed tripping time, whichever is greater, beyond the prescribed ride-through duration, the DER shall comply with the ride-through requirements specified in this section prior to tripping.

In all other cases, the ride-through requirements shall apply until 160 ms or 1% of the prescribed tripping time, whichever is greater, prior to the prescribed tripping time.

DER ride-through requirements specified in this section shall take precedence over all other requirements within this SRD with the exception of tripping requirements listed in item a. above. Ride-through may be terminated by the detection of an unintentional island. However, false detection of an unintentional island that does not actually exist shall not justify non- compliance with ride-through requirements. Conversely, ride-through requirements specified in this section shall not inhibit the islanding detection performance where a valid unintentional islanding condition exists.

Other grid support utility interactive inverter functions statuses

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

Definitions

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

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

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

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

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

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

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

Table I: Inverters' Voltage Trip Settings

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

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design	Comparison to IEEE Std 1547-2018 (2nd ed.)
$V > 1.20$	Cease to Energize	N/A	0.16	Identical
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A	Identical
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A	Identical
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A	Identical
$0.88 \leq V \leq 1.10$	Continuous Operation	infinite	N/A	Identical
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T = 3\text{ s} + 8.7\text{ s}\,(V - 0.65\text{ p.u.})$	N/A	Identical
$0.45 \leq V < 0.65$	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
$0.30 \leq V < 0.45$	Permissive Operation [b]	0.16	N/A	See footnote b
$V < 0.30$	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.)
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF
Q(V), Volt-Var Function with Watt or	OFF
SS, Soft-Start Ramp Rate	ON Default value: 2% of maximum current
FW, Freq-Watt Function OFF	OFF

L Appendix L

Village of Hyde Park, Inc.	2013

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Hyde Park, Inc.
Calendar year report covers	2013
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,326

System average interruption frequency index (SAIFI) =	**4.1**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**1.6**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	10	993
2	**Weather**	7	4,423
3	**Company initiated outage**	2	1,745
4	**Equipment failure**	10	1,478
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	2	12
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	4	89
	Total	35	8,739

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

Village of Hyde Park, Inc. 2014

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Hyde Park, Inc.
Calendar year report covers	2014
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,326

System average interruption frequency index (SAIFI) = 1.6
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.0
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	6	717
2	**Weather**	2	870
3	**Company initiated outage**	0	0
4	**Equipment failure**	7	415
5	**Operator error**	0	0
6	**Accidents**	2	140
7	**Animals**	1	1
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	1	1
	Total	19	2,144

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

	Village of Hyde Park, Inc.	2015

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Hyde Park, Inc.
Calendar year report covers	2015
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,330

System average interruption frequency index (SAIFI) =	**1.3**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**4.7**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	2	6,721
2	**Weather**	4	93
3	**Company initiated outage**	0	0
4	**Equipment failure**	5	91
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	6
11	**Unknown**	9	1,251
	Total	21	8,162

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

Village of Hyde Park, Inc.	2016

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Hyde Park, Inc.
Calendar year report covers	2016
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,339

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**0.3**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**1.1**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	5	68
2	**Weather**	2	109
3	**Company initiated outage**	0	0
4	**Equipment failure**	4	30
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	2	39
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	6	187
	Total	19	433

		Village of Hyde Park, Inc.		2017

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Village of Hyde Park, Inc.
Calendar year report covers	2017
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,340

System average interruption frequency index (SAIFI) =	**1.6**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**3.1**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	13	524
2	**Weather**	2	83
3	**Company initiated outage**	0	0
4	**Equipment failure**	4	32
5	**Operator error**	0	0
6	**Accidents**	2	1,322
7	**Animals**	2	101
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	3	4,727
11	**Unknown**	3	34
	Total	29	6,823

		Village of Hyde Park, Inc.				**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	Village of Hyde Park, Inc.
Calendar year report covers	2018
Contact person	Karen Wescom
Phone number	802-888-2310
Number of customers	1,374

System average interruption frequency index (SAIFI) = 1.5
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.9
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	23	3,503
2	**Weather**	2	188
3	**Company initiated outage**	0	0
4	**Equipment failure**	4	21
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	3	30
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	1
11	**Unknown**	5	66
	Total	38	3,809