8. Portfolio Evaluation

Portfolio evaluations in our most recent IRPs have focused considerable attention on how best to fill substantial open positions in energy and capacity that were anticipated based on the expiration of major long-term PPAs (from Vermont Yankee and Hydro-Québec) that historically provided the majority of our needs. Vermont's renewable energy framework at the time (centered on the SPEED program) was primarily focused on the short-term, and lacked the type of specific guidance that many states had established through Renewable Portfolio Standards or other frameworks. As a result, our IRP portfolio evaluations have also explored the tradeoffs between a fairly wide range of potential strategies and renewable energy policies that GMP and Vermont could potentially pursue.

The context for this 2018 IRP is much different. Significant new long-term PPAs (along with much smaller new GMP-sponsored generation sources) have been added to our portfolio in recent years, reducing our forecasted open positions and yielding a portfolio of sources that is more diverse and more renewable. In addition, Vermont's Renewable Energy Standard (RES), which took effect in 2017, established specific guidance for the types of renewable resources and energy transformation that Vermont utilities should pursue, and at what pace. Since our 2014 IRP, Vermont renewable policy resources (particularly net-metered generation, along with Standard Offer) have assumed a prominent role in the state's energy supply, and now represent a signficant cost driver and planning uncertainty for our portfolio.

With these important developments in mind, the 2018 portfolio evaluation focuses largely on how to achieve these policy goals and RES requirements most cost-effectively for our customers, and explores the factors that could change the type and timing of our future decisions regarding renewable energy and transformation. We strive to deliver low-cost, low-carbon, incredibly reliable energy services to our customers. The RES framework provides three metrics (relating to distributed renewable suppy, total renewable supply, and energy transformation and decarbonization) that are critical to our portfolio's performance. In the context of resource planning, we seek to manage two additional objectives: portfolio diversity and a balance between flexibility and stability.

This chapter summarizes the RES framework and describes these portfolio attributes in more detail; portfolio evaluations and conclusions follow. The chapter concludes with an explanation of the wholesale market price outlooks used in some of the portfolio analyses.

VERMONT'S RENEWABLE ENERGY STANDARD

Vermont's RES was established by 30 V.S.A. §8002-8005. It establishes a set of mandatory requirements for Vermont's distribution utilities to obtain portions of their power requirements from two broad classes of renewable sources. Compliance is demonstrated by the retirement of renewable attributes in the form of Renewable Energy Certificates (RECs). The program also requires that Vermont's distribution utilities engage in energy transformation projects that lower costs and fossil fuel consumption.

The RES requirements are broken into three tiers. Tier I requires that 55% of 2017 retail electric sales be obtained from renewable energy sources, which, broadly defined, include both new and existing renewables. This requirement increases by four percent every three years until reaching 75% renewable in 2032.

Tier II requires that one percent of retail electric sales in 2017 be obtained from new distributed renewable generation sources, increasing by 0.6% per year to a total obligation of 10% in 2032. This distributed generation requirement (which represents a subset of the Tier I total renewable obligation) requires new distributed renewable projects located in and connected to the grid in Vermont, with a maximum project size of less than 5 MW and have achieved commercial operation on or after July 1, 2015.

Finally, Tier III requires that distribution utilities implement energy transformation projects such as electric vehicles, cold climate heat pumps, and weatherization above baseline values. The obligation begins at 2% of retail electric sales in 2017 and increases by 0.667% per year to a maximum of 12% in 2032.

Each RES tier features an Alternative Compliance Payment (ACP), with Tier I's ACP starting at $10 per MWh while Tier II and Tier III have a beginning ACP of $60 per MWh. After the first year, these ACPs escalate annually based on an inflation index.

PORTFOLIO OBJECTIVES AND PERFORMANCE METRICS

Our analysis is based on five resource planning objectives: low cost, low carbon, renewable energy, reliability, and flexibility.

Low Cost is an important objective. We use the average portfolio cost (including power costs and transmission by others) in $/MWh as the relevant performance metric. We seek to avoid substantial annual increases, and to maintain an average rate of increase lower than the rate of general inflation. We also seek to remain competitive relative to average market rates ($/MWh) for power and transmission that other utilities and retail electricity suppliers in New England would face.

Low Carbon reflects the estimated average emission rate of CO_2 (in pounds per MWh) for our power supply portfolio. We compare our portfolio average emission rate to estimates of the New England average emission rate, which we represent at about 600 pounds per MWh,[66] declining over time to reflect state efforts to lower their emission profiles. We also depict an estimate of the system residual emission rate for New England. This represents average emissions for generation certificates that are not retired by market pariticpants (for example, to meet state RPS requirements or other reasons.

Renewable Energy content is estimated on an annual basis in terms of retired RECs that are eligible with Tier I—total renewables—and Tier II—distributed renewables—as fractions of retail sales. We also track the implications of potential paths of complying with Tier III—energy transformation (as discussed in Chapter 4: Declining Electricity Demand).

Reliability means lack of interruption of electric service to customers. Reliability is measured using the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI). From a resource planning perspective, reliability reflects a goal to stabilize (or "hedge") power costs to provide a measure of price stability to our customers (particularly in the near term), while leaving some flexibility and exposure to market in the long term. This metric is measured by the fraction of our energy load requirements that is met with fixed or stable-priced sources.[67]

Flexibility. Finally, the balance between portfolio flexibility and stability is primarily measured by the size of our long-term, fixed-priced resource commitments compared to the total energy requirements. The higher the percentage of resource commitments, the

66 The average emissions in the NEPOOL Generation Information System (GIS) of roughly 900 pounds per MWh appears to be significantly affected by relatively small fractions of power from non-fossil fuel plants (such as biomass, trash to energy), suggesting that those rates might be overstated. We have therefore depicted regional average emissions at a lower rate of 600 pounds per MWh.

67 In this metric, the most notable treatment of our sources is that energy from oil- and natural gas-fired plants is not treated as "hedged" in the long term, and the HQ-US long-term PPA is treated as partially hedged because a portion of its PPA pricing is determined based on an electricity market price index.

more stable the resulting portfolio costs tend to be. The tradeoff is that the portfolio also becomes less flexible, as it does not respond as much or as quickly to changes in the wholesale markets.

Table 3-1 summarizes the five resource planning objectives and their performance metrics.

Objective	Attribute	Metric
Low Cost	Metric 1	Average portfolio cost ($/MWh)
	Target 1	Limit increases to less than general inflation
	Target 2	Average portfolio cost is less than the regional benchmark
Low Carbon	Metric 1	Our annual average portfolio emission rate (CO_2 pounds per MWh)
	Target	Our average emission rate is well below the regional average
Renewable Energy	Target 1	Achieve annual Tier I requirements
	Target 2	Achieve annual Tier II requirements
	Target 3	Achieve annual Tier III requirements
	Target 4	Achieve each RES requirement in a cost-effective way, at average costs substantially lower than ACP
Reliability	Metric 1	SAIFI and CAIDI
	Metric 2	Percentage of resource commitments compared to loads
	Target 1	Estimated open positions 100% hedged by start of operating year
	Target 2	Five-plus years in the future, portfolio is less than fully hedged
Flexibility	Metric 1	Long-term ratio of fixed (or stable) priced MWh to total energy requirements
	Target 1	Five-plus years in the future, portfolio is significantly less than fully hedged. Percentage may float as long as the portfolio remains below regional rate benchmarks
	Metric 2	Resource expiration sequence and duration
	Target 2	Resource expirations are layered, and do not expire all at once

Table 8-1. Resource Planning Objectives and their Performance Metrics

The final measure of portfolio flexibility and stability is the sequencing or layering of expiration dates of resources over time. Flexibility can be balanced with stability when long-term resources (PPAs primarily) expire in different years and different amounts expire at different times. The largest sources in our committed portfolio (PPAs from HQ-US and NextEra Seabrook) are much smaller than corresponding long-term hydroelectric and nuclear commitments we held in the past, but it is notable that both of these purchases expire in the mid-2030s.

Because these objectives are frequently interrelated, they should ideally be kept in balance with each other. The pursuit of any one objective to the detriment of another can create a tradeoff that is not desirable under different circumstances. Ideally, resource plans seek to balance the objectives; as markets, policy and technology change, the portfolio may need to be managed to maintain a state of dynamic equilibrium between them.

PORTFOLIO EVALUATION METHODOLOGY

The portfolio evaluation process combines three common analytical methods (budget estimation, portfolio-based multi-attribute analysis; and sensitivity analysis) to gain insights into how different portfolios perform under a range of future market conditions.

Budget Estimation

The resource planning process begins with our current portfolio of committed resources, and reasonably anticipated resource changes that are contained its current five-year financial forecast. These resource changes include scheduled expirations of existing PPAs, inclusion of new PPAs that are presently committed, and the addition of reasonably anticipated new resources such as those that are supported by Vermont renewable policies or programs (such as net metering and the Standard Offer program). With these changes, the resulting resources are projected past the five-year horizon using estimates of their price and volume on a monthly on-peak and off-peak basis, and balanced against our estimated load requirements (see Chapter 4: Declining Electricity Demand).

Reference Portfolio

The foundation for the portfolio evaluation is the Reference Portfolio, which is intended to illustrate the portfolio of loads and resources that would result from current commitments and policies, without any substantial new long-term resource commitments.

The Reference Portfolio is based on the projected sources and load requirements with the following assumptions being among the most notable:

- Projected gaps between energy requirements and committed resources are assumed to be purchased (or, as appropriate, sold) on a short-term basis at our current base case forecast of future wholesale energy market prices. Similarly, projected capacity requirements in excess of Our committed sources are assumed to be met using short-term layered forward purchases (or from ISO-New England directly) at prices consistent with our current Base case FCM price forecast.

- Net metering in our territory is assumed to grow at a pace of 20 MW/year. The 20 MW/year pace seems to be a good reference point because it is consistent with the lowest growth of net-metered capacity observed in any year since 2014, yet this pace of new distributed solar (from all sources, not only net metering) would also be sufficient to meet the annual growth of Tier II requirements over the next decade. The PUC has recognized that the faster pace of net metering growth in recent years has put upward pressure on utility power costs and electricity rates for customers, and that lower-cost distributed renewables are available. The PUC therefore lowered net metering payment rates by limited amounts in 2018 to seek an appropriate balance between supporting the net metering industry and limiting rate impacts to non-participants.
- Vermont's Standard Offer program is assumed to run its current course (ultimately supporting about 127.5 MW of distributed renewables). The program is not assumed to be renewed or replaced, because the distributed renewable sector in Vermont has matured greatly since the Standard Offer program was initiated, and the RES framework is now in place to support the future development of substantial new distributed renewables.
- Three solar and storage projects we proposed (with total solar capacity of about 15 MW, and battery storage capacity of about 6 MW and 24 MWh) are assumed to receive CPGs and reach commercial operation (and start contributing to our supply of Tier II RECs) in 2019.
- Charts evaluating our supplies of Tier I, Tier II, and Tier III are presented assuming that we do not make any future purchases to meet projected shortfalls (to illustrate potentially required volumes that are yet to be procured), while estimated portfolio power costs are developed assuming that we will purchase any projected Tier I or Tier II shortfalls at current Base case price outlooks.

Portfolio-Based Multi-Attribute Scenario Analysis

This chapter evaluates our portfolio (first the Reference portfolio, and ultimately for an illustrative future portfolio) across the several metrics[68] listed in Table 3-1. Consistent with our past IRP analysis, most attributes are estimated annually, and presented in their natural units (such as renewable percentage or CO_2 pounds per MWh)—that is, they are not weighted or otherwise translated for comparison with other metrics. Portfolio costs

[68] This chapter does not evaluate our portfolio with respect to SAIFI and CAIDI, although we discuss how some distributed resources have the potential to help improve these metrics.

are first estimated using base assumptions for market prices for energy, capacity, and two types of RECs, and later tested under alternative future outcomes for these markets. Similarly, multi-attribute evaluation of the Illustrative Future Portfolio is discussed in "Illustrative Future Portfolio" (page 8-44).

Sensitivity Analysis

The use of sensitivity analysis allows us to gain insight into how sensitive a portfolio's attributes are to sources of uncertainty. The sources of uncertainty that were analyzed using alternative assumptions (differing from the base case) include wholesale market prices for energy, capacity and RECs; the pace of future net metering in our territory; the pace of future Tier III supply; and future electricity demand. These alternative outcomes were formed using input from external experts and our own assessment of market prices and risks. (Chapter 4: Declining Electricity Demand discusses a potential range of alternative outcomes for Tier III supply.)

Some of these sensitivities lead to illustrations of potentially different outcomes or decisions. For example, a higher or lower pace of net metering growth in our territory could change the timing of our need for additional Tier II (distributed renewable) resources; higher or lower paces of acquisition for Tier III supply could potentially change the amount of Tier II RECs that we retire toward RES requirements (and therefore the amount available for resale); and regional REC prices for Class 1 renewables and existing renewables could affect the amount of RECs that it is cost-effective for us to sell versus retiring them to meet Tier I requirements. The relative sensitivity of our portfolio costs to several of these variables are visualized using a "tornado chart" format that ranks relative impacts on the net present value (NPV) of the portfolio's costs through 2035; these results are shown in "Illustrative Future Portfolio" (page 8-44).

IRP Alignment with Our Financial Forecasting

The first five years of the resource planning model are largely consistent with our then-current five-year financial forecast. The primary difference is that the energy, capacity, and REC market prices in the resource plan were updated to reflect our updated base case outlooks (which are explained in detail in "Market Price Inputs to the Portfolio Analysis" on page 8-57"). In addition, the IRP portfolio analysis reflects a base case rate of growth of 20 MW per year for net metering in our territory, compared to about 24 MW in the financial forecast. As a result, the base forecast in the IRP does not match up precisely to our internal financial forecast, but for many of the models' key components (including the volumes and prices for major supply sources, which drive most power costs) the inputs are the same, and the bottom-line cost projections are similar.

The resource plan estimates and analyzes net power supply and purchased transmission costs. These costs represent the majority of our cost of service, and they tend to change directly under the alternative strategies and scenarios discussed in this chapter. Capital-related costs of all existing and future T&D assets, administrative and general expenses, and non-power operations and maintenance costs are not modeled. As a result, the resource plan appropriately reflects tradeoffs in power supply costs and related metrics, but is not a forecast of total retail electric rates that our customers would pay under the different scenarios.

Nominal Analysis

The resource-planning model is an entirely *nominal* analysis. All of the costs and prices in the analysis are expressed in nominal dollars (which include the effects of general inflation in the economy over time), and therefore reflect prices and costs that are projected to occur in each year in question. No additional translation or escalation is needed to incorporate the effects of inflation.

Peaking Resources

Our fleet of peaking combustion turbine and diesel generating units—along with flexible load and storage resources—can also provide significant value to customers. These resources do not typically produce large quantities of energy. Rather, their value and operations tend to be determined by relatively specialized aspects of the power market and grid (for example, periods of very high electricity demand and market prices; ISO-New England ancillary service markets, support of the local transmission and distribution grid). The benefits and considerations associated with these resources are discussed in a separate section, rather than the broader multi-attribute analysis of portfolio characteristics and needs.

Signposts

The "Signposts" section (page 8-54) discusses "signposts" as a concept. These are metrics (from a local, regional, or national perspective) that could serve as indicators of developments or trends that will inform future transitions or resource choices. Because of the more dynamic nature of our energy system and portfolio, unlike previous IRPs, we believe defining the signposts and how we will adjust as a result of what they tell us is more realistic than claiming an optimal portfolio and resource mix for the next 10 years that will become stale.

EVALUATION OF THE REFERENCE PORTFOLIO

This section presents our evaluation of the Reference Portfolio (which is defined in the previous section) across a range of metrics.

Attribute: Open Energy Position

Figure 8-1 presents our forecasted long-term energy "gap chart"—comparing our projected supply sources to the energy requirements to serve forecasted retail sales.

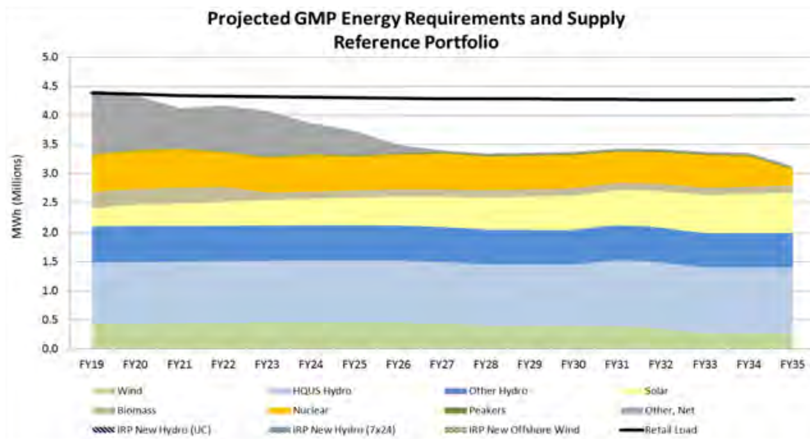

Figure 8-1. Projected Energy Requirements and Supply

Some notable observations that emerge from this view:

- By design, long-term committed sources are somewhat less than our projected load requirements. Layered short-term forward energy purchases (which are most of the declining grey source on the upper left) bridge the gap between long-term committed sources and load requirements, declining gradually over the next five years and leaving a minimal average open position for the next three years.
- Solar PV is projected to continue as a growing long-term source. For net metering, which represents most of the solar PV growth, this chart depicts net metered excess energy as a power source (as opposed to a reduction in retail sales).
- Aside from layered short-term purchases, our portfolio consists largely of long-term sources that will remain in place over the next decade.
- This chart extends about 15 years, through our fiscal year 2035. Two major PPAs (HQ-US and NextEra Seabrook), amounting to roughly a third of our annual energy

supply, are slated to expire shortly thereafter. During the 2020s as these expirations grow closer, they will probably become a more significant consideration in our portfolio design. For example, it could become appropriate to acquire some volume of additional long-term resources (and accept some loss in open position and portfolio flexibility) to limit the fraction of our supply that needs to be replaced at one time.

Figure 8-1 depicts the energy sources that we use to offset our energy purchase obligations in the ISO-New England market; it does not depict our sales of RECs to other parties (or our purchases of RECs that do not provide energy). This chart therefore does not depict the ultimate fuel mix (after accounting for REC sales and purchases) that may ultimately serve our customers and meet RES requirements; this ultimate mix will be addressed in detail later in this section.

Finally, it is significant that Figure 8-1 compares sources and requirements on an annual basis. While this provides a useful first-order indication of portfolio length, our energy positions also feature some significant seasonal and temporal differences within each year that are not evident from this annual view. Based on the characteristic shapes of customer loads and committed sources (for example, substantial fractions of solar PV and hydroelectric sources, and a large HQ-US PPA that delivers in a "7x16" pattern), our open energy position tends to be weighted toward winter and toward off-peak hours, while supply tends to be more in balance with load during other seasons and exceeds load during peak periods in spring.

Figure 8-2 illustrates how our net energy position tends to vary on a monthly basis, using the fiscal years 2025 through 2027 as an example. To effectively hedge its forecasted open energy positions, we need to generally match the expected output of supply resouces (including short-term purchases and sales, as needed) to the period of need. On this chart, the blue area represents projected output of our committed sources, with intermittent renewable sources represented at their normalized (that is, long-term average) values. The red area represents estimated volumes of net market purchases (on a monthly basis) that would be needed to supplement our committed supply to serve our total energy requirements. The green area reprsents estimated net energy resales, during periods when our committed sources are projected to exceed load requirements.

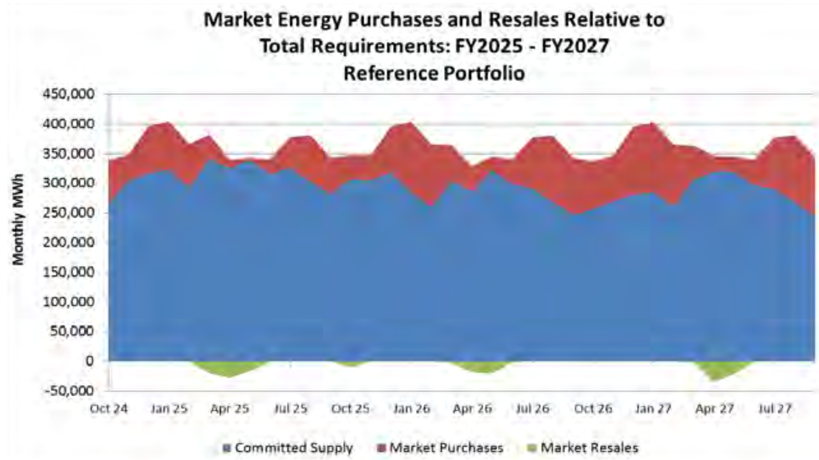

Figure 8-2. Market Energy Purchases and Resales Relative to Total Requirements: 2025–2027

Figure 8-2 shows three distinct patterns that have implications for our short- and long-term planning process.

- Our total energy requirements (the top of the red area) consistently follow a seasonal pattern that is highest in the peak winter months. Energy requirements are also relatively high in the mid summer months, and noticeably lower in spring and fall.
- Our open positions (when requirements exceed supply, requiring additional purchases) tend to be concentrated in the winter sesaons. This can be seen by the relative size of the red purchase areas in the winter months of each year. As a result, our forward energy purchase descisons in the coming years will focus more on this period, which features different market price drivers and risks (described in Chapter 3: Regional and Environmental Evolution) than the other months.
- Lastly, Figure 8-2 shows a notable new feature in our energy positions where we are projected to be in a consistant surplus positon during peak hours in the spring season (as illustrated by the green area). This feature reflects the lower seasonal energy requirements during spring, along with higher seasonal hycro generation and the extraordinary growth of distributed solar generation, which tends to produce at relatively high rates in these months.

Attribute: Price Stability

Figure 8-1 illustrated our projected energy open position on an annual basis. By design, our portfolio features significant long-term open energy positions to limit the degree that our portfolio costs and electric rates could diverge from those in neighboring states, and to maintain some flexibility to acquire resources to meet strategic objectives (that is, acquire competitively priced renewables to meet RES requirements) or to accommodate unanticipated declines in the electricity requirements of our customers. After our current set of layered short-term energy purchases expire, the magnitude of that open position is roughly 20% for the remainder of the 2020s. This is somewhat less than in previous long-term analyses, primarily because of declining retail energy sales and forecasts, along with the large increase in net-metered solar generation that has occurred in our territory (and is anticipated to continue).

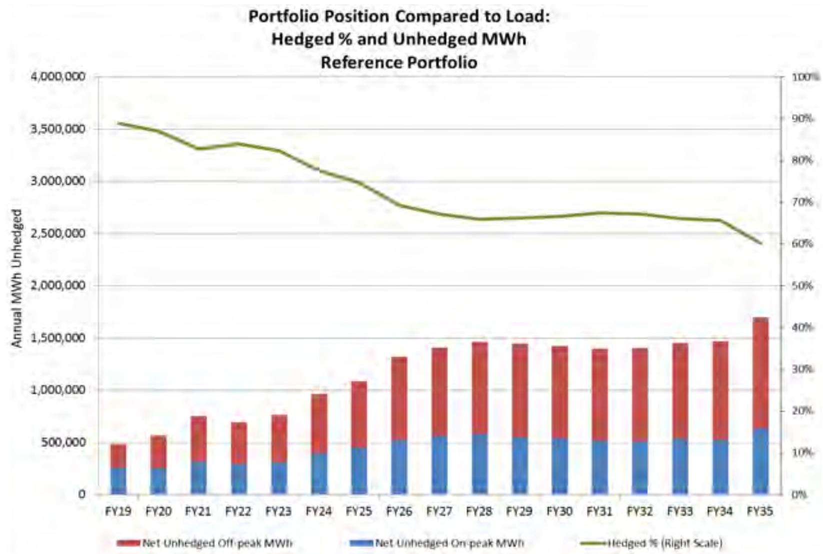

Figure 8-3. Portfolio Position Compared to Load: Hedged Percent and Unhedged MWh

Figure 8-3 views our estimated energy open position from the perspective of price stability, first from the perspective of the fraction of forecasted load requirements that are hedged—that is, matched with supply sources that feature fixed or stable pricing. The green line in Figure 8-3 depicts the estimated fraction of forecasted requirements that are hedged, on an annual basis. This fraction declines by design from about 100% in the first year to roughly 70% through the early 2030s. A decline of the hedged fraction in the final year of the chart foreshadows the expiration of our HQ-US and NextEra Seabrook contracts in 2038 and 2034, respectively.

When viewed in combination with Figure 8-1, this level of long-term stability indicates that we do not have a strong need for additional new long-term resources for the purpose of stabilizing energy costs for our customers. By simply replacing its layered short-term energy purchases as they expire over time, we could likely achieve a reasonable portfolio balance between energy cost stability and flexibility over the next decade. Our primary long-term portfolio needs during this period appear likely to be associated with other strategic goals: meeting renewable energy requirements in a cost-competitive way; managing peak-driven capacity and transmission costs; and achieving cost-effective electrification and decarbonizing projects.

The stacked red and blue bars on Figure 8-3 provide an indication of when during the year, peak or off-peak hours, our forecasted energy needs and surplus are likely to occur.

- Our primary estimated net short positions are during off-peak hours (indicated by the red area), in volumes of about 200,000 MWh to 300,000 MWh during the early 2020s, increasing to about 700,000 MWh to 800,000 MWh in the late 2020s.
- We are projected to be long, on average, during peak hours for the next several years. This is, in part, because of rapid growth of net-metered solar generation along with other solar sources, which produce primarily during peak daytime hours (while in evening hours, we are often a net purchaser). In the 2020s, a modest net short position during peak hours (depicted by the blue area) on the order of 100,000 MWh to 200,000 MWh develops.

Attribute: Open Capacity Position

Figure 8-4 presents our projected long-term capacity "gap chart"—comparing our projected capacity sources to our projected share of regional capacity requirements[69] to serve our customers' needs.

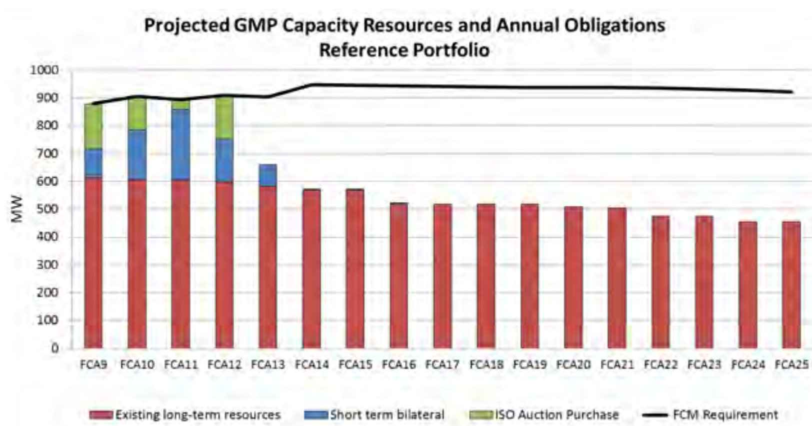

Figure 8-4. Projected Capacity Resources and Annual Obligations: Reference Portfolio

The red bars represent capacity from existing long-term sources (such as long-term PPAs and GMP-owned generating plants), while the blue area represents layered short-term purchases consistent with the strategy. The green area represents estimated our capacity requirements that were not matched by either of these sources, but for which the price of ISO-New England purchases is largely known at this time because the annual capacity auction for the relevant year has already been conducted.

The primary observations that emerge from this view are similar to those for energy. By design, long-term committed sources are somewhat less than our projected capacity

69 Figure 8-4 shows capacity volumes for Forward Capacity Auction #19 through FCA #25. This covers the period May 2018 through June 2035.

requirements. Layered short-term forward capacity purchases bridge the gap between long-term committed sources and load requirements; these expire gradually over the next several years. To replace these expirations and protect against short-term FCM price fluctuations, we are presently seeking an additional short-term capacity purchase (for delivery starting in FCA #13) at a price reflective of our current market view which is moderate by historical standards.

Aside from these layered short-term capacity purchases, our portfolio consists largely of long-term sources that will remain in place over the next decade. The scale of long-term capacity gap is, by design, somewhat larger in percentage terms than for energy—partly because annual Forward Capacity Auctions are conducted about three years in advance. These auctions are the primary driver of the price that GMP and other load serving entities pay to purchase capacity in the FCM. Peak-reducing resources like battery storage and controllable loads have the potential to act as a capacity hedge by cost-competitively reducing our capacity market exposure.

Attribute: RES Tier I Supply

Figure 8-5 presents our projected long-term Tier I "gap chart"—comparing our committed Tier I-eligible supply to projected Tier I requirements on an annual basis.

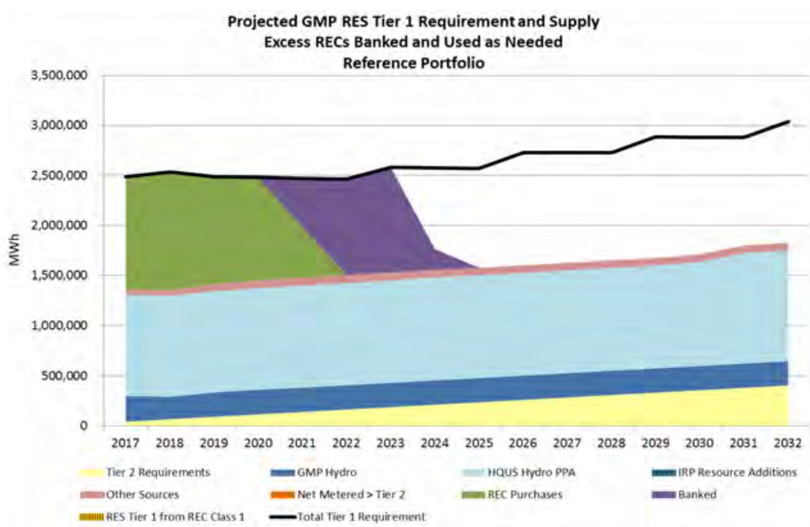

Figure 8-5. Projected Tier I Requirement and Supply Excess RECs Banked and Used Reference Portfolio

The following are notable features of this illustration:

- Tier II requirements, which we plan to meet, are depicted by the yellow area at the bottom of the chart. By statute, the total renewable requirement increases in a step function every three years.

- This illustration assumes that we will continue to sell our substantial inventory of RECs that are eligible for Class 1 or similar RPS markets in neighboring states, with the revenues used to reduce our net power costs and electric rates, and that RECs associated with these sources will therefore not be available for RES compliance.
- The "REC purchases" and "banked" sources refer to unbundled hydroelectric REC purchases (see Chapter 5: Our Increasingly Renewable Energy Supply). We expect to over-comply with our Tier I requirements in the next few years, and to bank some of our REC supply for compliance with our requirements in the early 2020s.

This summary projects that we will be well-supplied with Tier I-eligible sources in the near term, largely because of the long-term hydroelectric sources in our portfolio together with significant purchases of hydroelectric RECs. In the long-term, our Tier I supply is projected to be well short of the Tier I requirements, in part because of the substantial REC sale program that is assumed to continue during this period.

Later in this chapter, in the context of potential long-term resource additions, we explore the potential implications of procuring additional long-term renewable supply that would fill some of this gap, while in "Sensitivity Analysis" (page 8-20), we explore the implications of retiring some or all of the regional Class 1 RECs that we presently sell.

Attribute: RES Tier II Supply

Figure 8-6 presents our projected long-term Tier II "gap chart"—comparing our projected Tier II-eligible supply to projected Tier I requirements on an annual basis.

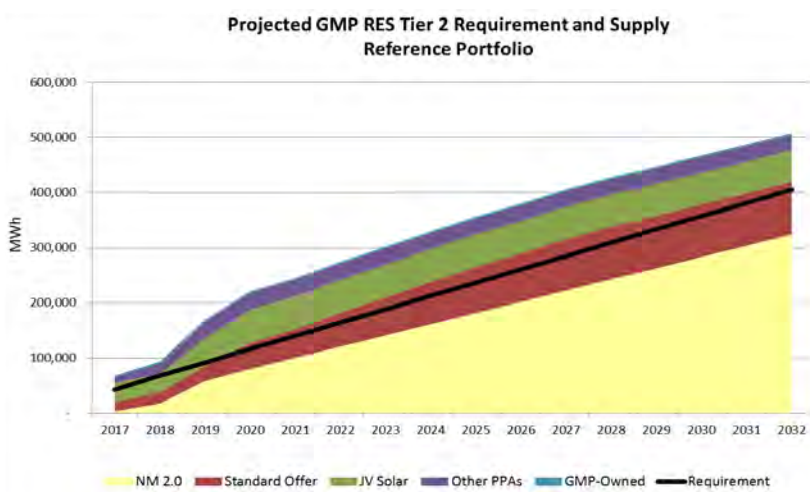

Figure 8-6. Projected Tier II Requirement and Supply and Potential Tier III Reference Portfolio

The Tier II supply reflects our base case assumption that net metering in our territory, which is almost entirely solar PV, will increase at a pace of 20 MW/year. We assume that, consistent with experience since 2017, almost all net metering customers will choose to assign the RECs associated with their projects to GMP (rather than retaining the RECs and receiving a significantly lower payment rate).

Based on these assumptions, we are projected to be well-supplied with Tier II RECs through the planning horizon. Our actual supply could vary significantly, higher or lower, based on the actual pace of net metering. In "Sensitivity Analysis" (page 8-20), we explore the implications of net metering growth turning out higher or lower.

Attribute: Greenhouse Gas Emission Profile

One of the key touchstones for our portfolio design is low carbon content for our electricity supply. Over the last five years our portfolio has had significantly lower CO_2 emissions (pounds per MWh) than New England as a whole, based on substantial reliance on hydro and nuclear sources.[70] We project that our average emission profile will continue to remain lower than the regional average in the future; this is substantially because of the increasing RES requirements reaching 75% renewable by 2032, which we assume will be met primarily with non-emitting renewable sources. The projected emissions profile of our Reference portfolio, along with an Illustrative Future Portfolio, is presented in "Illustrative Future Portfolio" (page 8-44).

Attribute: Reliance on Intermittent Supply Sources

The rapid growth of renewable generation led by solar PV and wind in Vermont, combined with a substantial base of hydroelectric plants, has led to an increasing intermittence in our portfolio. Intermittent sources are projected to assume an increasing role in the next decade, as increasing volumes of net-metered generation and Standard Offer projects are completed.

[70] We also receive substantial energy from renewable plants (such as wind and solar) from which we presently sell the associated RECs. To the extent that RECs associated with a volume of renewable energy are sold, we do not count that energy as renewable or zero-emitting when calculating greenhouse gas emissions. Rather, we assume that it takes on the characteristics of the Residual System Mix.

This trend can be seen in Figure 8-7.

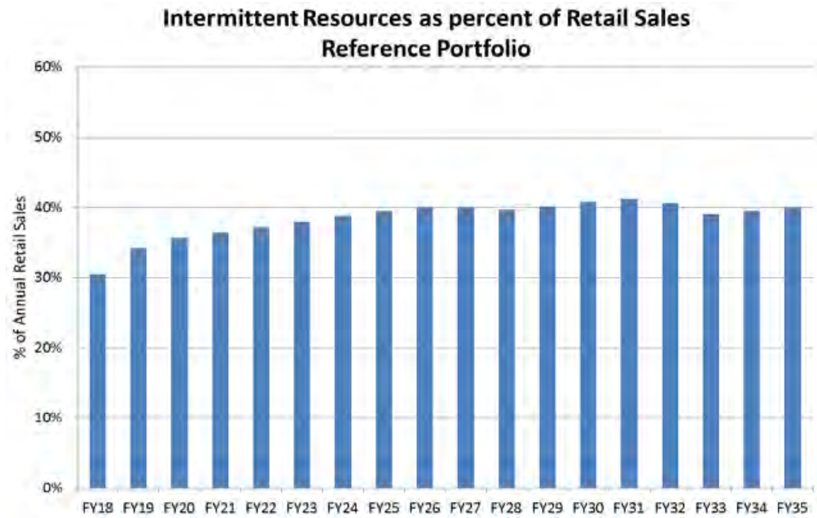

Figure 8-7. Intermittent Resources as a Percent of Retail Sales Reference Portfolio

Intermittence, in the context of an electric generation resource, means the resource does not generate on a level and consistent basis for long periods. Rather, intermittent resources are powered by renewable sources such as wind, sun, and water, which may have periods of high availability followed by periods of low or no availability. Each of these sources features a characteristic seasonal output profile, and in some cases a diurnal output profile; these can be incorporated into asset valuation and portfolio planning to a significant degree. In addition, each of these sources is subject to short-term influences such as cloud cover and precipitation that can create large fluctuations in daily and even hourly production volumes compared to the seasonal averages.

Figure 8-8 illustrates potential day-to-day variations in output for Vermont solar projects, using actual output from the fleet of net-metered solar projects in our territory on two consecutive days in April 2017. A very sunny day is depicted by the red dashed line, with maximum mid-day output approaching 100 MW; a very cloudy day is depicted by the blue dashed line, with maximum mid-day output of only about 20 MW. The sunny day provided an average of roughly 40 MW more generation than an average day in that month, while the cloudy day provided an average of roughly 25 MW less than the daily average.

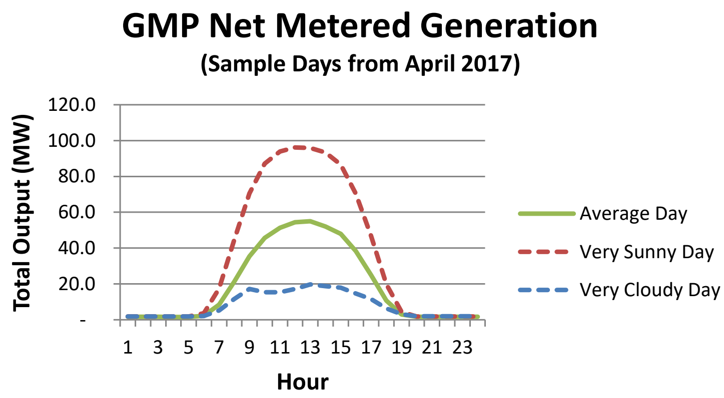

Figure 8-8. Daily Net-Metered Generation

Wind generation in New England tends to be stronger in winter months, and exhibits strong hourly and daily output variations around the long-term average since its output tends to vary with the cube of wind speed. Vermont hydro generation is seasonal with high output during the spring run-off and with more limited output during summer months when there is limited rainfall and rivers tend to dry out. The mode of operation can also affect hydro availability, with run-of-river generators providing output that is totally dependent on water flow versus dispatchable units that have ponding capability and at least some ability to shape and time their output.

We generally seek to balance our energy sources and load requirements within each month. This can be accomplished by taking into account the characteristic seasonal shapes of our intermittent supply sources. A balanced monthly supply does not, however, provide balance in all days and hours. The implication of relying on intermittent sources is that day-to-day fluctuations in intermittent production yield corresponding fluctuations in the volume of energy that we need to purchase or sell from the ISO-New England spot market. When combined with strong fluctuations in hourly LMPs, fluctuations in intermittent generation can yield noticeable short-term fluctuations in net power costs.[71] These will tend to offset over time, but sustained variances in intermittent output can drive variances of sufficient magnitude that they noticeably affect collections from or returns to customers under our power supply adjustor.

We track reliance on intermittent sources in this portfolio evaluation as a potential differentiator between sources that are similar with respect to other characteristics like price, RES eligibility, or emissions, for example. The intermittency attribute also provides a directional indication of the trend in potential short-term portfolio cost fluctuations that we may see over time. We are currently seeking to obtain consultant

[71] On the other hand, during periods when LMPs are relatively stable, offsetting temporary fluctuations in intermittent generation output tend to cause only modest fluctuations in net power costs.

assistance to model our energy portfolio, along with market prices, on an hourly basis in the context of a regional market simulation model. While we recognize the limits of such models, it is possible that this type of simulation tool will be able to help us characterize the short-term cost variance associated with intermittent generation, along with load and other factors, more quantitatively in future IRP analyses.

Finally, we note that the development of flexible energy resources like battery storage or controllable load tends to be complementary to a portfolio that is increasingly renewable and intermittent. Such resources have the potential to mitigate some of our exposure to short-term variances associated with fluctuations of renewable output—for example, through battery discharge during hours when renewable output is low and LMPs are high, or conversely through battery charging during hours when renewable output is high and LMPs are low.

Attribute: Portfolio Costs

Figure 8-9 illustrates the trend in our projected annual portfolio costs.

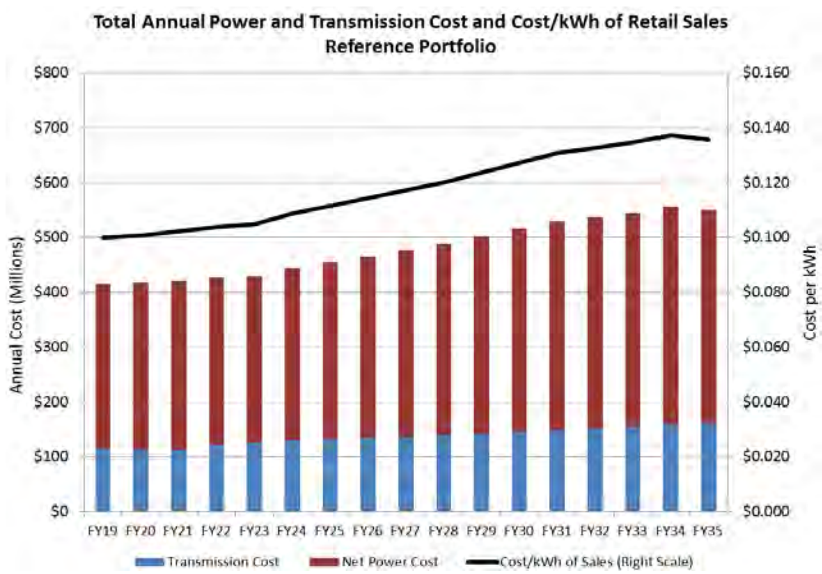

Figure 8-9. Total Annual Power and Transmission Cost and Retail Sales Cost per kWh Reference Portfolio

Power supply-related costs are the majority, but the blue portion shows that expenses for transmission by others (primarily Regional Network Service) amounts to roughly two cents per kWh of retail sales in the near term, increasing over time.

SENSITIVITY ANALYSIS

In contrast to the portfolio evaluations in our most recent IRPs, the Reference portfolio does not show any large, near-term needs to address sufficiency of supply or extreme market price exposure with respect to needs for energy, capacity, or Tier I and Tier II. If the future unfolds along the lines of the base case assumptions with respect to Vermont renewable resources and wholesale markets, there does not appear to be an urgent near-term need for new long-term resources to address these products. Continuation of our short-term programs for the purchase of energy and capacity, and for the sale of regional Class 1 RECs, is likely to yield a reasonable balance of portfolio attribute outcomes.

However, review of the Reference Portfolio evaluation suggests that several uncertainties could alter this conclusion, affecting the timing and magnitude of our portfolio needs. These uncertainties include:

- The future pace of net metering growth in our territory will affect our net power costs, as well as the volume of Tier II-eligible RECs that we hold for potential regional Class 1 REC sales, and the extent to which we have sufficient Tier II supply to address a potential shortfall of Tier III supply.
- The actual pace of Tier III supply that we experiences in the coming years could potentially produce a need to retire Tier II RECs. The pace of Tier III electrification measures will also affect our annual retail electric sales and energy requirements, although in a much more limited proportion.
- If future electricity sales to our customers turn out higher or lower than the base case forecast, the size of our open positions for several products, and relative need for long-term resources, will change.
- Since we are currently a meaningful seller of regional Class 1 RECs, future market prices for these RECs will remain a noticeable influence on our net power costs (with higher Class 1 REC prices generally resulting in lower net power costs for us). In addition, if future regional Class 1 prices remain very low (that is, well below $10 per MWh), it could make sense for us to retire for the purpose of Tier I compliance, some or all of the RECs that it presently sells to out-of-state buyers.
- In addition to these uncertainties, which are mostly or entirely outside of our control, we could choose to fill some of its forecasted future open position—for example, to lock in additional Tier I-eligible supplies, or to address resource needs focused on the long-term and the winter season.

Each of these themes is explored in the following sections via sensitivity cases. In this context, a sensitivity case means that one of the portfolio components or market price outcomes turns out differently from the base case, over the long term.

Sensitivity: Future Growth in Net-Metered Generation

Our Reference portfolio evaluation reflects future growth of net metering in our territory at a pace of 20 MW per year. This pace is high by regional and national standards, and sufficient to meet essentially all growth in our Tier II requirements during the next decade, even without help from larger, lower-cost MW-scale renewables. This pace would be consistent with a future in which residential and smaller group net metering projects continue at a substantial pace, but larger projects (over 150 kW) see more limited growth.

This sensitivity examines the portfolio implications that would be associated with actual net-metered capacity increasing faster or slower than the base case: The High Net Metering sensitivity reflects sustained growth of 30 MW/year; the Low Net Metering sensitivity reflects the growth of 10 MW/year. The most direct implication of faster or slower net metering growth would be more or less Tier II-eligible supply.

Figure 8-10 illustrates our Tier II gap chart for the High Net Metering growth sensitivity.

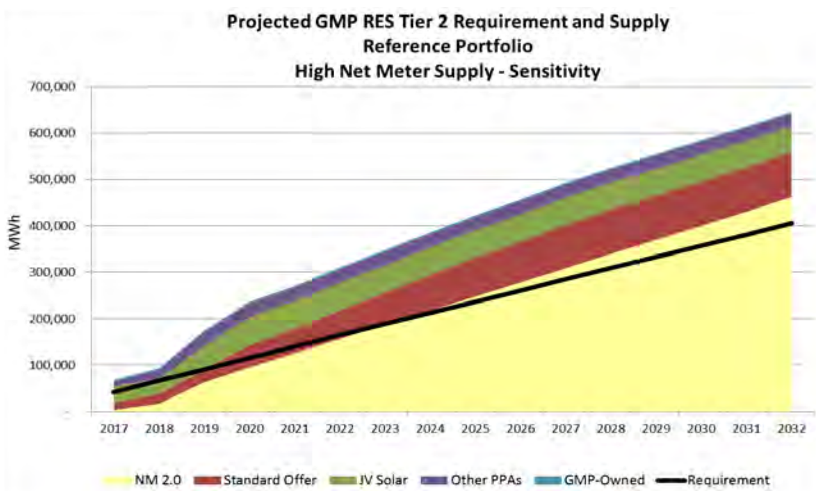

Figure 8-10. Projected Tier II Requirement and Supply Reference Portfolio: High Net Meter Supply

Figure 8-11 illustrates our Tier II gap chart for the Low Net Metering growth sensitivity.

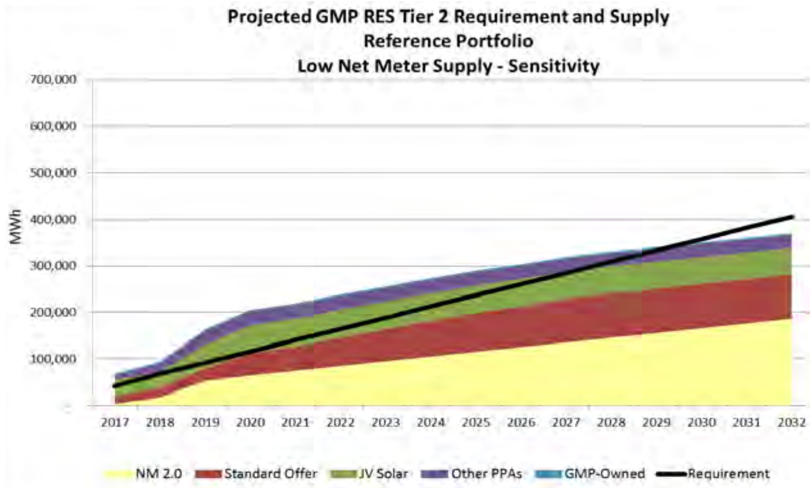

Figure 8-11. Projected Tier II Requirement and Supply Reference Portfolio: Low Net Meter Supply

Not surprisingly, the High Net Metering sensitivity (30 MW/year) shows that our supply of Tier II-eligible sources would grow more rapidly than the Tier II requirements, increasing our projected surplus of Tier II supply substantially over time. We would not need additional Tier II supplies to meet our requirements. In addition, we would have sufficient Tier II RECs to cover substantial shortfalls in Tier III supply if needed. In this future, we would expect our procurement of distributed renewables to be limited to projects that are cost-effective based on projected wholesale power prices alone, or that would provide a specific local benefit (for example, transmission and distribution deferral, pairing with storage to enhance local grid resilience). Estimated portfolio costs in this sensitivity are somewhat higher than the base case, because of the presence of additional net metering at prices higher than the wholesale power and REC value that they provide.

In the Low Net Metering sensitivity (10 MW/year), the pace of growth in net-metered generation fills a substantial fraction of the increase in our Tier II requirements, but not nearly all of it. Our projected near-term surplus of Tier II supply gradually erodes, nominally reaching zero in about 2029. Considering that there will be some degree of uncertainty in the pace of completion of new Tier II sources, as well as in the actual output of Tier II sources (for example, because of fluctuations in cloud cover), we would likely procure additional Tier II supply in the mid- to late-2020s under this future. Estimated portfolio costs in this sensitivity are somewhat lower than the base case, because of lower volumes of relatively high-priced net-metered supply.

Sensitivity: RES Tier III Supply

There is a substantial degree of uncertainty in the pace of Tier III transformation opportunities that can be found in our territory. Key uncertainties include the volume of C&I electrification opportunities, the pace of adoption of electric vehicles in Vermont, the future price of oil relative to electricity, and the pace of customer adoption of cold climate heat pumps and other devices.

Figure 8-12 presents our projected Tier III "gap chart"—comparing our projected Tier III-eligible supply to projected Tier III requirements on an annual basis for the next decade, under the base, high, and low Tier III supply scenarios presented in Chapter 4: Declining Electricity Demand.

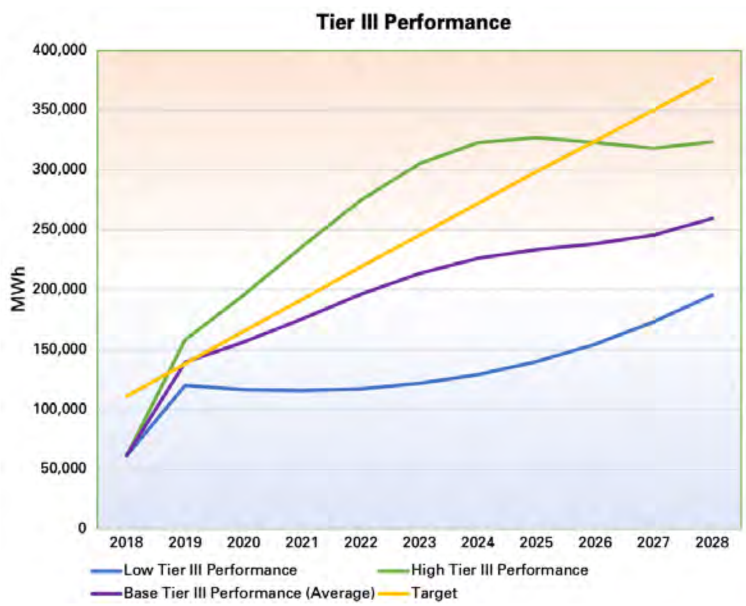

Figure 8-12. Tier III Supply Performance Scenarios

The potential Tier III supply paths shown here are quite wide; to some extent this reflects the fact that the RES program is new and we have has only limited experience with planning and acquisition of Tier III resources. The range also reflects the inherent uncertainty in some of the key drivers (for example, availability of cost-effective C&I electrification opportunities, pace of adoption of electric vehicles in Vermont). The indicated shortfalls relative to the Tier III requirement in many years are therefore illustrative. We plan to seek Tier III compliance in a cost-effective way—pursuing sufficient programs (and offering sufficient incentives) to meet the requirements without paying more than necessary, and ideally spending much less than the Tier III ACP, on average. To the extent that the pipeline of future Tier III supply appears to be insufficient to meet the annual requirements, we would expect to review our program offerings including incentive levels with an eye toward stimulating greater customer participation.

Under the RES framework, another option available would be to meet the Tier III shortfall by retiring additional Tier II RECs (quantities in excess of the annual Tier II requirements). Figure 8-13 illustrates the potential portfolio implications of pursuing this option.

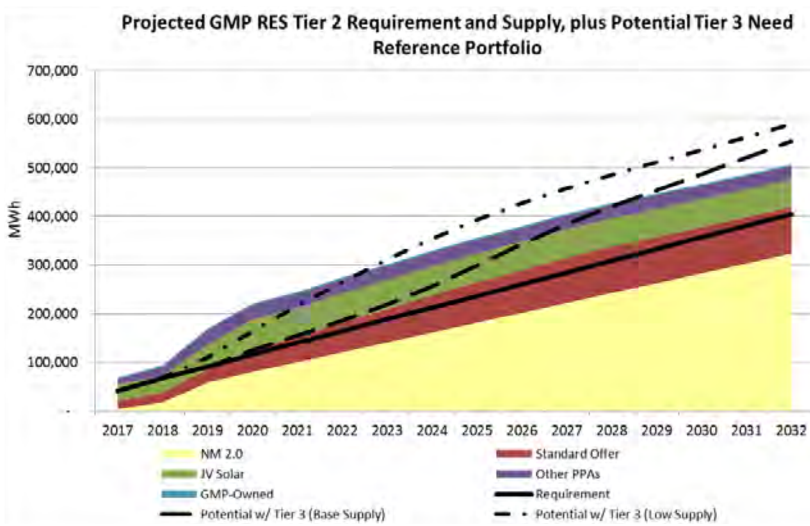

Figure 8-13. Projected Tier II Requirement and Supply Plus Potential Tier III Need Reference Portfolio

Specifically, the solid line represents our estimated annual Tier II requirements. The two new dashed lines illustrate the higher total volume of Tier II-eligible RECs that we would need to also meet the entire projected shortfall of Tier III supply under the Base and Low scenarios of Tier III supply (identified in Chapter 4: Declining Electricity Demand).

The lower dashed line indicates that our presently projected supply of Tier II-eligible RECs would, under base assumptions for electric sales and net metering growth, be sufficient to cover potential shortfalls of Tier III supply under the Base Tier III supply case for most of the next decade. In this future, we would have fewer RECs to sell to the regional Class 1 market; to address a projected gap in the late 2020s, we would presumably evaluate banking Tier II RECs in the mid-2020s, or procuring additional Tier II supply.

The higher dashed line indicates that under the Low Tier III supply scenario, in which Tier III supply falls substantially short of requirements very early in the planning horizon, almost all of our projected supply of Tier II-eligible RECs would be required to meet the Tier III shortfall. Under this future, we would likely seek to procure additional Tier II supplies in the early 2020s.

Because these sensitivities conceptually represent bounding cases, since we would explore other Tier III program options if low supply begins to materialize, they provide an indication of the significant magnitude of Tier II RECs that could potentially be needed to assist with Tier III compliance under some circumstances, at least in some years. Thematically, this indicates that the adequacy of our forecasted Tier II REC supply could depend to some degree on the actual path of Tier III supply, and that the pace of our actual Tier III supplies and pipeline of Tier III projects for future years, should be monitored as a leading indicator of Tier II needs.

One other implication of retiring additional Tier II RECs above RES requirements to cover a shortfall in Tier III supply, is that our portfolio emission profile would likely be slightly lower, as additional distributed renewables displace market power sources supplied by natural gas or the regional system residual mix.

Sensitivity: Regional Class 1 REC Market Prices

Long-term PPA sources and owned renewable plants provide a substantial inventory of RECs that are eligible for Class 1 RPS compliance in neighboring states, but not eligible for Tier II because of the size or age of the plants. Although regional REC price expectations have declined significantly, the Reference Portfolio evaluation assumes that it will continue to be cost-effective to sell those RECs and use the revenues to reduce our net power costs and electric rates, rather than retiring them for Tier I compliance.

This sensitivity explores what would be the portfolio implications if regional Class 1 REC prices turn out significantly higher or lower on a sustained basis, reflecting the High and Low REC Price scenarios (outlined in “Market Price Inputs to the Portfolio Analysis” on page 8-57).

The first-order effect of higher or lower regional Class 1 REC market prices is that we would receive less REC revenue for its projected inventory of salable Class 1 RECs (that is, those that are eligible for Tier II compliance). Based on a projected REC inventory on the order of 800,000 MWh during the mid-2020s, the High REC Price scenario would increase our REC revenues, and therefore lower net power costs and retail rates, by about $7 million/year, relative to the Base REC Price scenario. Through the year 2035, this amounts to about $57 million (present worth) of additional revenue. The Low REC Price scenario has the opposite effect, lowering projected REC revenues and increasing net power costs by about $64 million (present worth).

An additional consideration is that if regional Class 1 RECs were to fall to historically low levels, it could become increasingly cost-competitive for us to retire some or all of its REC inventory for compliance with Tier I. Retiring these RECs would forego some amount of resale revenue at then-current Class 1 market prices, while reducing the amount of RECs we would need to procure from other renewable sources. For a sense of scale, Figure 8-14 illustrates the magnitude of Tier I requirements that we could meet by retiring all of our projected Class 1 REC inventory, starting in the mid-2020s.

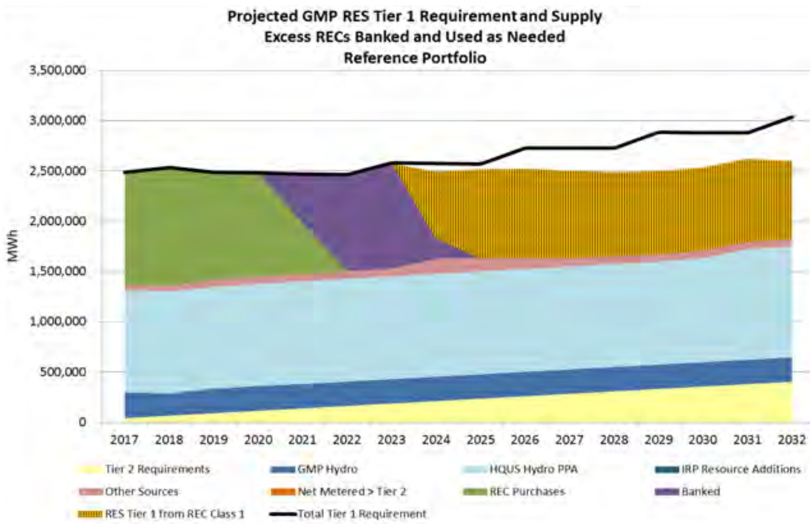

Figure 8-14. Projected Tier I Requirement and Supply Excess RECs Banked and Used Reference Portfolio

As illustrated in Figure 8-14, retirement of our full inventory of Class 1-eligible RECs could cover the vast majority of our projected Tier I needs in the 2020s.

It would likely only be cost-effective to retire our Class 1-eligible RECs in a low REC price environment. Foregoing regional Class 1 REC sales beginning in 2024 under the Base market price outlook would increase our estimated net power costs by $8 million or more per year. Under the High market price outlook, retiring the Class 1 RECs could increase our net power costs by $15 million or more per year.

Sensitivity: RES Tier I REC Prices

Our estimated Tier I open (short) position is substantial—on the order of 1 million MWh/year starting in the mid 2020s—making the purchase of additional renewable supply in the 2020s a priority. Based on the projected open position, this sensitivity explores the potential impact on our net power costs if future prices to acquire Tier I-eligible RECs turn out along the lines of the high and low price outlooks (summarized in "Market Price Inputs to the Portfolio Analysis" on page 8-57.)

Table 8-2 summarizes the results.

Tier I REC Price Outlook	REC Purchase Cost ($NPV)	Difference from Base Outlook
Base	$14.5 million	n/a
High	$24.4 million	$9.9 million
Low	$4.5 million	($10 million)

Table 8-2. Estimated Cost of Tier I REC Purchases

This sensitivity indicates that the High and Low Tier I REC price outlooks present a range of plus or minus $10 million (present worth) relative to the base price outlook. In the late 2020s, the upside cost exposure in individual years is roughly $2 million to $4 million. This range of cost uncertainty is not extraordinary in the context of our total portfolio costs, and we have some time to address it. But the exposure is meaningful, and indicates that in the coming years, we should be on the lookout for potential resources—such as low-priced REC purchases that may become available, or opportunities to affordably acquire existing renewables on a long-term basis (via PPAs or asset purchase)—that could be used to mitigate this exposure at reasonable prices.

Sensitivity: Retail Electricity Sales

This sensitivity explores the portfolio implications of electricity sales turning out higher or lower than the base case forecast. The high sales case reflects an increase of three percent over the next five years (that is, by 2024); this could credibly be driven by a combination of one or more of the following: more Tier III electrification projects than reflect in the base case; somewhat more favorable economic and demographic trends; and net metering growth slower than the base case forecast. The low sales case reflects a decrease of five percent by 2024. This would be consistent with a future in which the drivers of electrification, economic growth and net metering exert downward pressure on electricity sales; we test a larger decline because of the risk of discrete sales reductions if one of our major industrial customers were to reduce its operations.

Figure 8-15 and Figure 8-16 illustrate the scale of impact that these changes would have on our projected energy and capacity gap charts.

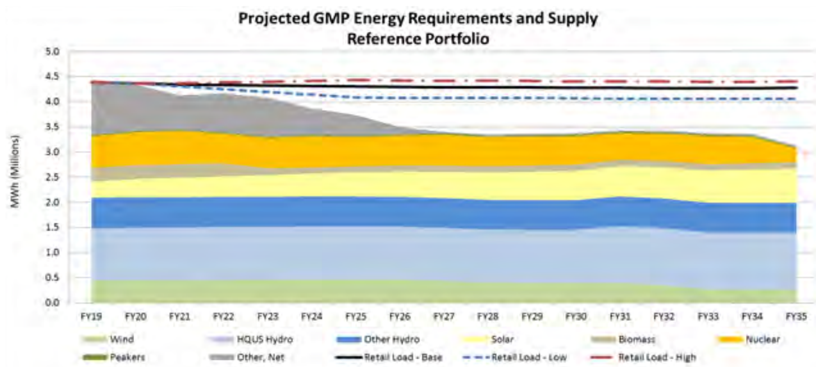

Figure 8-15. Projected Energy Requirement and Supply Reference Portfolio

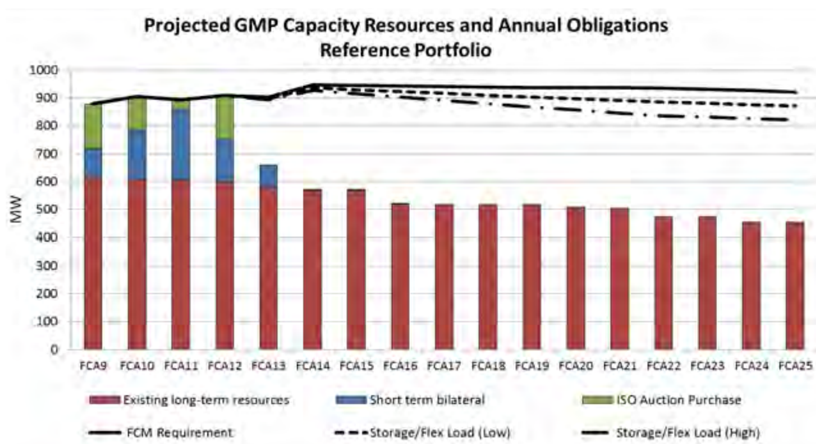

Figure 8-16. Projected Capacity Resources and Annual Obligations Reference Portfolio

The High sales sensitivity would not leave us "open" (and exposed to market prices) to a degree that is concerning. The Low sales sensitivity would, however, more noticeably reduce our estimated open energy position, and would moderately increase the fraction of our portfolio that is hedged by long-term sources. At these levels, our portfolio costs would still be moderately linked to trends in regional market prices, so this observation is not a fatal flaw that requires action at this time. It does, however, reinforce our sense that large long-term energy sources are not presently needed for the purpose of energy cost stability, and that the primary motivation for adding new long-term sources should be to address other strategic priorities—such as achieving the RES requirements; managing peak-driven costs; and enhancing grid resiliency.

POTENTIAL LONG-TERM RESOURCE ADDITIONS

The Reference portfolio does not show any large, near-term needs to address sufficiency of supply or extreme market price exposures with respect to most portfolio products. Our estimated need for additional renewable resources to meet Tier I requirements is substantial, however, at roughly 800,000 to 1 million MWh/year from the mid-2020s onward. This raises the question of whether it may be appropriate for us to seek additional long-term renewable sources in the 2020s, to reduce this gap and what types and volumes may be appropriate. While our committed sources are estimated to cover up to 80% of projected energy requirements during most of the 2020s,[72] long-term resources acquired during the 2020s could also help replace some of the substantial energy resources that are scheduled to expire by 2035.

To explore the potential merits of additional long-term renewable sources to our portfolio, we tested the following illustrative potential additions. Each of these resources would provide renewable energy on a long-term basis, and would likely offer price stability past the expiration of our major sources in the mid-2030s, but their portfolio implications would be somewhat different.

50 MW of plant-contingent existing hydro. This resource reflects a long-term PPA for the output of one or more existing hydro plants, or a purchase of existing hydro capacity in the region. Existing plant-contingent hydro has the potential to provide renewable energy to meet Tier I, along with some amount of capacity, on a long-term basis. An asset purchase or long-term PPA would most likely feature stable or fixed pricing over time, although we would be open to exploring other pricing arrangements. If this resource featured an average annual capacity factor of 50%, it would provide about 220,000 MWh/year. For this analysis, we assume that plant-contingent hydro would be priced consistent with our 2016 PPA purchase from the Sheldon Springs plant—which starts under $50/MWh for energy and RECs, with capacity priced separately. Plant-contingent hydro output would be delivered on an as-available basis, subject to some amount of intermittency based on streamflow variations; the degree of correlation with our existing hydro fleet would depend to some degree on what (if any) ponding capacity it possesses, and the river system it is located on including its geographic proximity to our plants.

25 MW of firmed hydroelectric purchases, similar to the product that Massachusetts is seeking to purchase via the proposed NECEC line in Maine. We assume that this product would be delivered on a firm "7x24" basis, thus providing hydroelectric energy

72 Because not all committed sources feature fixed or very stable prices, the fraction of our portfolio that is hedged on a long-term basis is somewhat less.

without the fluctuations in output that are associated with plant-specific sources. For this analysis, we assume that firmed hydro would be priced consistent with publicly reported pricing for the commodity portion of the NECEC purchase (not including transmission), starting at around $53/MWh] and escalating gradually over time.

50 MW of offshore wind. This resource would likely be pursued for its long-term price stability and winter-weighted output profile. We assume pricing of about $75/MWh (escalating over time), consistent with reported pricing recently offered to Massachusetts. Relative to onshore wind, offshore wind would likely offer value through higher capacity ratings and diversity of output profile, and potentially through higher locational energy value. Because offshore wind plants would not be eligible for Tier II because of their large size and location, it appears likely that if we purchased the output under a bundled contract, we would use the energy and capacity as hedges for our open positions, and sell the RECs to the regional Class 1 market (of course, using the revenues to lower power costs and retail rates).

Our primary opportunity to participate in either of the latter two resources would likely be as part of a large solicitation conducted by a neighboring state or aggregation of buyers.

We would also consider purchasing additional solar PV, particularly if solar prices continue to decline over time. We did not test this option here because our portfolio already contains a large and increasing amount of solar PV, and the solar PV output profile is not as well-matched with our projected energy portfolio needs which are largest during winter months and off-peak hours.

The firmed hydro product is somewhat more costly under our assumptions than the plant-contingent hydro; this is only illustrative because pricing for hydro resources would be project-specific based on market conditions at the time the resources are offered. The primary attribute difference is that the plant-contingent hydro source would add 50 MW of additional intermittent supply to our portfolio.

Figure 8-17 shows our resulting reliance on intermittent sources with the plant-contingent hydro purchase—several percent higher than for the Reference Portfolio.

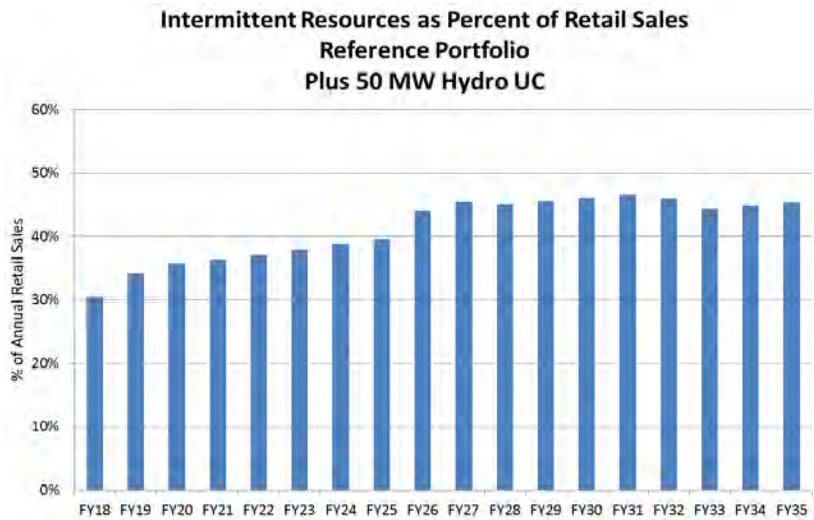

Figure 8-17. Intermittent Resources as Retails Sales Percent Reference Portfolio, plus 50 MW Hydro

The higher assumed price of offshore wind in our analysis is partly although not fully offset by higher assumed weighting] of output toward higher-value winter months. Offshore wind would increase our intermittent reliance to a similar degree as the plant-contingent hydro option, so we do not present a unique chart here. We note, however, that fluctuations of offshore wind output would probably be somewhat less correlated with our existing onshore wind portfolio than a plant-contingent hydro purchase in New England might be to our existing hydro fleet.

Based on these initial observations, it appears that each of these renewable sources could be credible long-term additions to our portfolio. We therefore include smaller amounts of each of these sources in the Illustrative Future Portfolio, with assumed acquisition dates ranging from the mid to late 2020s. We emphasize these resources are in no way committed, in part because their availability is uncertain, particularly for the firmed hydro and offshore wind options. In addition, the relative attractiveness of these resources will depend significantly on when they become available and at what price levels, along with other factors—such as expectations for regional Class 1 REC prices; relative capacity values; and correlations of output of the plant-specific sources with the output of our existing portfolio and wholesale energy market prices.

PEAKING AND FLEXIBLE LOAD RESOURCES

As is discussed in several places in this IRP, flexibility of resources is an important factor when evaluating the importance of any given asset on a distributed grid. Battery storage systems prove themselves to be one of the most flexible of the resources that are currently available. In this section, we dive a little deeper into the value streams, or 'use cases', that a battery system can provide and how we intend to utilize storage as an integral part of our portfolio. We discuss these value streams primarily with respect to battery storage resources, but many of them also apply to flexible load resources that can manage electricity use at key times. It should be noted that in this instance, the term 'portfolio' does not simply mean our power supply portfolio, but our entire operating energy space including the T&D system, resiliency, and emergency power along with direct customer power quality resources.

Currently, the greatest monetized value stream of energy storage comes from its peaking capabilities: by reducing our net system load at the time of the annual ISO-New England peak, we can limit our share of regional capacity obligations; reducing load during monthly Vermont peaks can limit our share of regional network service transmission costs. Batteries can be considered very similar to a peaking generator, such as a diesel generation set. When the peaks occur, these resources can be dispatched, and in the case of batteries, actually lower the net load that we are pulling from the bulk system in real-time, thereby lowering the cost that our customers ultimately pay into the capacity market or for transmission service. This peak management role can be viewed as one of the simpler value streams provided by battery storage. It has been the largest monetized value stream for our battery projects to date. As described in Chapter 5: Our Increasingly Renewable Energy Supply, 1 MW of peak reduction during a single hour from a battery storage system can save customers as much as $100,000 annually in reduced capacity costs.

As of December 1, 2018, we have the following storage systems deployed:

- 2 MW/1 MWh Lithium Ion System + 2 MW/2.4MWh: Stafford Hill Solar Storage facility
- 1 MW/4 MWh Lithium Ion System: Panton Storage Park
- 5 MW/13.5 MWh Lithium Ion System: Powerwall 2.0 residential batteries

The following projects are in development and permitting:

- 2 MW/8 MWh Lithium Ion System: Essex Solar-Storage Park
- 2 MW/8 MWh Lithium Ion System: Milton Solar-Storage Park
- 2 MW/8 MWh Lithium Ion System: Ferrisburgh Solar-Storage Park

In addition to the value derived from reducing system peaks, the following are values that are either being captured with existing battery storage or battery storage could be able to capture.

Energy Arbitrage. Because a battery can act as a load and a supply source at different times, it makes for an ideal energy arbitrage resource—meaning that it can store energy when spot market prices are low and discharge that energy later when marginal prices are higher, capturing the value of that spread with less cycle losses to lower net power costs. A noticeable amount of natural energy arbitrage should be achievable through use of storage resources for peak reduction purposes, because LMPs during near-peak conditions when a battery would discharge, tend to be significantly higher than during non-peak hours when the battery would recharge. As we get more skilled about optimizing the performance of battery and flexible load systems, we will strive to achieve greater energy arbitrage by taking advantage of spreads between high and low or even negative spot market energy prices that occur during non-peak days.

Operating Reserves. Under FERC Order 888, the FERC ordered all ISOs to allow battery storage to participate in any markets just as any other resource could. This means battery storage can become an operating reserve resource in the ISO market. However, when participating in a market like this, you may have to give up other peaking benefits so weighing the value of this against the loss of those other opportunities is important in deciding if you should pursue this value stream.

Intermittent Generation Output. The difference in solar generation on sunny days and cloudy days can amount to many tens of MW of spot market energy market exposure for us. Hydroelectric and wind generation can also fluctuate greatly on a daily and hourly basis. In combination, output fluctuations from renewable sources can amount to over 100 MW. While such fluctuations are not costly when spot market prices are stable, having a tool to blunt the financial exposure associated with significant swings in intermittent output is useful from a portfolio perspective; storage and flexible loads at a large enough scale can fit that role nicely. These resources provide us with a resource that can either soak up, or fill in gaps that are created when significant swings in PV output occur.

Frequency Regulation. ISO-New England runs a market that compensates fast acting resources for providing quick power response on the time scale of a few seconds, to maintain a stable frequency on the regional grid. This service has traditionally been provided by large natural gas and hydroelectric power plants, but can now be provided by fast-responding battery systems. Our Stafford Hill solar storage facility was the first battery system to participate in the commercial frequency regulation market in New England.

In addition to power supply benefits, battery storage provides a useful tool to manage the local T&D system as well as create a resiliency resource which include the following additional use cases:

Customer Resilience and Backup. Residential and Commercial customers can benefit from the emergency backup power that storage can provide. Certain C&I customers are also very sensitive to voltage fluctuations which can interrupt their business process costing the customer lost production or product.

System Resiliency. With the addition of substantial distributed solar generation across our system we have a resource that can potentially be tapped into during outages on the broader electricity grid. A key link to allow such local generation, or other forms like distributed hydro, to carry load on sections of our system is battery storage, along with sophisticated control systems that enable load generation and load to be balanced in real time. We are presently designing the protection and controls to be able to perform this function safely and reliably.

Distribution System Voltage and Var Management. In addition to the energy that can stored in the battery and released when needed, the inverter and associated power electronics provide the ability to dynamically adjust voltage and reactive power (Vars) at the point where the battery system is connected. This can be very important at sensitive C&I customer locations where voltage quality is extremely important to their process.

Distributed Generation Integration. As distributed solar PV installations increase, we are seeing more and more circuits reaching their saturation point. While current interconnection rules do not allow us to perform upgrades to the system to handle more generation, we anticipate that storage will be leveraged in some cases to manage interconnections. As an example, battery storage could be used in some instances as a load during the middle of the day, effectively absorbing excess local solar generation and then allowing that stored energy to be utilized later in the day and evening when local generation declines.

The Future of Energy Storage and Flexible Demand

Over the next decade, we will continue to develop storage capability through multiple channels. It will become increasingly important to harness value streams other than peak management, as there is essentially a finite amount of peak reduction that is practical and cost-effective. While small peak reductions may be practical using short-duration resources that are deployed only occasionally and for a few hours, reducing the Vermont or GMP peak by larger amounts (for example, many tens of MW) would require reducing load during more hours and more days.

Figure 8-18 shows an example of a near-peak December day, when achieving large peak reductions would have required us to reduce load across most of the day.

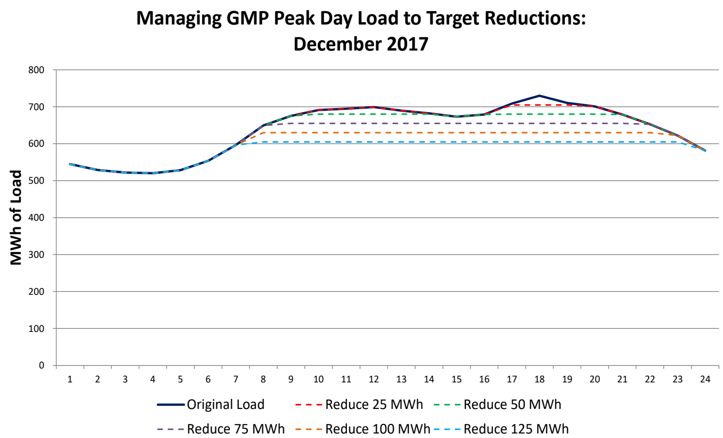

Figure 8-18. Managing Peak Day Load to Target Reductions: December 2017

The countervailing point to this, however, is that strategic electrification could provide pressure in the opposite direction, pushing peaks upward from some new loads that are not controlled as a flexible resource. The specific mix of storage and the locations will depend on a number of outcomes including some distribution analysis that is currently underway to rank circuits across the state for storage.

With that in mind, our current deployment strategy has several key parts.

Customer Resiliency and Power Quality

We expect to continue deploying storage systems behind the meter of residential and C&I customer locations to improve power quality and resiliency, and to leverage all the stacked values identified. The mechanism for deployment will be a combination of direct partnership and enhanced Bring Your Own Device (BYOD) value through other entities, for a target of about 47 MW over the next 10 years. This assumes that storage will be deployed at 25 C&I customer locations with an average installation size of 500kW per location and that 8,000 residential customers will install battery systems at an average size of 4kW per installation. This includes expansion of residential behind-the-meter programs as well as expanding the offerings into the C&I space. Additional opportunities arise when a C&I customer is exploring the need for a major capital expense replacing a traditional fossil-fuel-fired back up generation system.

T&D System Support, Renewable Integration, and Circuit Level Resiliency

The transmission and distribution system have traditionally been managed with a set of resources to maintain or improve reliability and manage power quality. These include the typical poles and wires along with voltage correction devices such as voltage regulators and capacitor banks, and sectionalizing equipment such as switches, circuit breakers and intelligent technology, including relays and automation equipment to manage it all. Battery storage systems are providing us with a new tool that can be used at the right locations on the distribution or transmission system to improve the power quality of the system or even defer the need for certain growth-driven transmission or distribution upgrades. It's important to note that at present we do not have load growth driving the need for transmission and distribution upgrades, so these opportunities do not exist today, however, over the next decade it is conceivable to think that there could be discrete pockets where growth-driven improvements are needed.

While load is not growing, distributed generation is growing and the distribution of electricity over our system is growing along with it. This is quickly resulting in multiple distribution circuits reaching their saturation points, which then require significant protection or other system upgrades. The next distributed generation project to request interconnection would be on the hook for those costs. While under the current interconnection rules for generation, we cannot unilaterally increase the generation-hosting capacity of a circuit, energy storage appears to be an excellent resource to unlock additional hosting capacity and allow smaller rooftop solar systems to continue installing, for example. With that in mind, we have put an illustrative target for these types of T&D beneficial systems over the next decade of approximately 25 MW of systems. These systems will be procured a number of different ways including RFP, GMP developed, or even through a fixed-price method like Bring Your Own Device. (Chapter 5: Our Increasingly Renewable Energy Supply further explains the circulate analysis and ranking that we performing prior to deploying any grid-scale storage systems larger than 1 MW.)

With any grid-connected battery storage system we will be looking to create local islanding capability of entire portions of the distribution system. In 2018, we engaged with an engineering consulting firm to develop the necessary protection and control systems that will allow for solar and battery systems to safely and reliably island the distribution system without the need for any rotating machines. We are starting with our Panton battery storage facility and will be replicating the design to our other solar and storage projects.

A Sense of Scale

The pace of deployment of storage and flexible loads in our territory is subject to uncertainty, and will depend on actual outcomes related to factors that include storage cost trends; adoption of battery storage for backup power and power quality by residential and C&I customers; the prevalence and timing of local distribution system use cases; and the feasibility of replacing some fossil-fired peaking capacity with grid-scale storage.

Table 8-3 presents an illustrative sense of potential scale for several different use cases; together these amount to a potential scale on the order of 100 MW. For these reasons, we do not know today how many of these use cases will materialize together, and at what pace.

Location	Type	Rationale and Value	Potential Scale	Comments
BTM	Non-Battery Resources	Leverage all available DERs to knock down peak, such as water heaters, car chargers, and heat pumps.	10 MW	Includes growth in electrification of fossil fuel processes.
BTM	Residential Resiliency	Grid transformation and customer resiliency. Assumes 8,000 homes over the next decade install some form of integrated battery storage.	32 MW	Includes Powerwall program and BYOD. Install smaller scale, residential battery systems in homes.
BTM	C&I Resiliency & Power Quality	Resiliency package offering to C&I customers in addition to peak value stacking; replacing fossil generation or providing power quality support for sensitive commercial processes. Assumes up to 25 customers over the next decade with an average installed system size of 500 kW per location.	12.5 MW	Leverage storage to optimize customer operations, reduce certain costs, and improve power quality and resiliency.
BTM and Grid	T&D System Support & Hosting Capacity	Potentially includes anything from T&D upgrade deferrals to distributed generation hosting and other location-specific improvements, including constrained areas (such as SHEI).	25 MW	As T&D constrained pockets arise over the next decade, storage and flexible demand will be evaluated as a solution.
Grid	Grid Connected Storage Systems	Strategically located storage on our distribution system to provide resiliency, T&D benefits, and all power supply benefits. Also includes fossil fuel peaker unit replacements.	25 MW	Mix of PPA, GMP-developed, and other projects connected at grid scale.

Table 8-3. Illustrative Storage and Flex Demand Portfolio Over the Next Decade

We have included in the Illustrative Future Portfolio a range of 50 to 100 MW of reduction in our capacity requirements from these storage and flexible load sources, ramping in over a ten-year period starting in 2022.

Peaker Retirement and Portfolio Storage

We own approximately 100 MW of instate peaking capacity at six plants. These are primarily oil-fired combustion turbines constructed in the 1960s that operate infrequently primarily because of their high fuel expense. They are relatively flexible and can generally operate for extended periods of time if needed. The primary value stream that these units provide to our customers is capacity (their FCM self-supply value was very helpful in recent capacity auctions when prices cleared as high as $9.55/kW-month); quick-start operating reserves can also provide significant revenues, although not as consistently. They can also provide value in the energy market during occasional times when ISO-New England energy market prices temporarily spike to unusually high levels.

Our current base case capacity market price outlook features prices ranging from $4 to $7/kW-month during most of the 2020s. This outlook is considerably below the estimated cost of entry for new combustion turbine or peaking plants, but the peaking plants still can achieve significant value under this outlook, while also limiting our exposure to market prices with the potential for significant year-to-year price volatility around the long-term trend. Under this market outlook, we expect that our peaking units will continue to be financially viable resources for our customers, with the market value of their output at least equal to their operating and capital costs.[73] On the other hand, if a major equipment failure were to occur at any of these plants, requiring a major capital investment to fix, it is possible that the plant's economic viability could be jeopardized. We would expect to review a plants estimated costs and value of output before making a large expenditure of this type.

For the Illustrative Future Portfolio, we assume that one of our peaking plants will retire in the mid-2020s, and that a second one will retire in the early 2030s. These dates are credible placeholder assumptions for these plants based on their ages but are strictly illustrative, since the actual long-term viability of the peaking units could vary greatly based on plant-specific equipment condition and performance in the coming years. In actual practice, when considering the potential retirement of an existing peaking unit, we would expect to consider several factors and questions, in addition to the costs and value of the plant's output:

- Would there be significant implications for the design and operation of the VELCO transmission system or our subtransmission system? Instate peaking plants sometimes provide operational support under some operating conditions like outages of transmission lines or equipment for example, and they are considered in design of the transmission system to handle contingency conditions. It is therefore possible that retirement of an existing peaking plant without replacement could trigger the need for some additional grid investment that would not be apparent based on wholesale power market prices.

73 The possible exception is the Rutland combustion turbine unit which has recently experienced more operating challenges than the other units; we are presently reviewing the long-term viability of this unit.

- Could repowering make sense? We have considered the replacement of existing peaking plants with equivalent or larger generation equipment. This type of repowering has the potential advantage of leveraging existing transmission and site infrastructure, to achieve lower cost than a similar plant at a "greenfield" site. Our current base case capacity price outlook features prices significantly below the estimated cost of new entry for newly constructed peaking plants, so a repowering option would likely not be cost-competitive in the next several years unless repowering could displace local grid investment that would otherwise be necessary.
- Could the site be productively used for an alternative peaking generation resource—including large scale battery storage? Our experience with battery storage to date has focused on projects sized 1 to 2 MW, but larger projects (for example, 5 MW to 15 MW) could achieve lower capital costs per kW through scale economies. It does not appear that battery storage is broadly cost-competitive with combustion turbine peaking plants at current pricing, although capital costs are anticipated to decline significantly during the next decade. In additional, when other potential value streams that storage can provide are considered, the economics of storage as a peaking resource can get a lot closer. It appears that replacement of aging peaking capacity will warrant consideration as a use case for battery storage in the 2020s, particularly if some amount of local grid investment would otherwise be necessary. We expect that a significant design consideration for this use case will be what size of storage system is required—to ensure capacity value in the FCM and to provide grid support if needed—since existing peaking plants are capable of running for many hours at a time.

LOCATIONAL CONSIDERATIONS

The New England electricity market is uncongested during substantial fractions of the year, allowing energy to flow freely across the transmission grid from power plants to serve load anywhere in the region. During uncongested conditions, LMPs at all locations differ only based on (typically modest) differences in the marginal loss component. In contrast, when there is congestion on the transmission system, the commitment and dispatch of power plants in the region must be constrained to avoid violating one or more operating limits. Examples of such operating limits include ones that are designed to avoid thermally overloading a transmission line, or to avoid conditions in which an unanticipated contingency event would have unacceptable operational impacts that would threaten reliable grid operation. During these conditions the congestion component of LMPs on opposite sides of export-constrained and import-constrained interfaces can differ significantly—which, in turn, can significantly affect the payments that generators receive for their output and the payments that load serving entities pay for their load obligations.

We are an integrated utility that purchases our load requirements from the ISO-New England market at the Vermont Load Zone, and sells the output of its generating sources and PPAs to the market at individual nodes. The net effects of transmission congestion on us can be positive or negative, depending on the location of the congested interface relative to our load and generation sources. Similarly, the value of a potential future generation resource (for example, a potential PPA to purchase output from a generating plant) to us and our customers can depend not only on the resource's total price, but also the extent to which the value of its output in the ISO-New England market is reduced (or enhanced) by effects of transmission congestion and losses.

The remainder of this section discusses congestion associated with transmission interfaces that are sometimes congested today, along with potential future congestion issues that could have implications for the operation of Vermont generation or the feasibility and cost of installing new generation.

Sheffield-Highgate Export Interface

The Sheffield-Highgate Export Interface (SHEI) area refers to a region in northern Vermont that is bounded by the 115 kV loop spanning from the Sheffield–Lyndonville (K39) line to the Highgate-St. Albans (K42) line. The amount of generation and transmission imports that delivery energy into this area far exceeds the load in the area. If certain system contingency events were to occur during some conditions, unacceptable operational consequences (such as a voltage collapse) could occur. ISO-New England established the SHEI interface to limit power flow from the area, by establishing a set of interface export limits[74] for various system conditions. During a limited fraction of the year (typically when local generation is high and local load is low, or when elements on the bulk transmission system are out of service), potential generation in the area can exceed the amount that could be accommodated by the export limit. In such times the SHEI becomes export-constrained, and a local generation source must reduce generation so that export limit is not exceeded. This adversely affects us and our customers (along with those of most other Vermont utilities) because the KCW plant is often required to reduce output, and because LMPs paid to our generating sources (such as HQ-US PPA, KCW, and Sheldon Springs hydro) during export-constrained conditions are lower than they would be if the interface were not constrained.

We are exploring potential solutions to cost-effectively mitigate SHEI congestion, as are others. VELCO's useful Northern Vermont Export study estimating the extent to which a range of potential solutions[75] would (individually, or in combination) increase the SHEI operating limits. We have collaborated with Enel (the owner of the Sheldon Springs plant) to install automatic voltage regulation (AVR) capability at the plant—a low-cost partial solution. We expect this system to be operational and to conduct ISO-New England testing in the near future, in hopes of increasing the SHEI limit in early 2019. GMP and other Vermont utilities, assisted by VELCO, are also collaborating in a working group to evaluate additional steps to cost-effectively reduce or eliminate current levels of SHEI congestion; we expect to identify one or more recommended steps in the first quarter of 2019.

Installation of additional generation in the SHEI area will tend to increase the frequency and depth of congestion on this interface, and will tend to offset the benefits of potential solutions that GMP and Vermont utilities may deploy on behalf of their customers to mitigate current levels of congestion. GMP and other Vermont utilities

[74] The SHEI limit is currently set to manage post-contingency voltage performance. VELCO indicates that if the voltage limit is substantially increased, thermal performance may also become limiting.

[75] Potential solutions include relatively discrete and limited-cost projects such as installation of reactive devices; reconductoring of existing subtransmission lines; and deployment of battery storage. Larger and more costly options include replacing existing transmission lines or constructing new lines.

have therefore intervened in Certificate of Public Good proceedings for some proposed distributed renewable projects that would be located in the SHEI area, in hopes of helping the Commission understand the costs that additional congestion could impose on Vermont customers. To the extent that future generation projects are proposed in the area (particularly large projects, and ones that would sell their output to out-of-state buyers rather than help to meet Vermont renewable requirements), we expect that petitioners will need to clearly demonstrate that their projects will not impose adverse congestion impacts on Vermont customers. This could potentially be accomplished by implementing or financially supporting one or more of the aforementioned SHEI mitigation steps.

Potential Transmission Import Projects

The most immediate potential for additional congestion on the Vermont transmission system appears to stem from major import transmission projects that proposed to deliver substantial volumes of power into Vermont. For example, in 2017, analysis of the proposed Vermont Green Line (400 MW, to deliver power for sale to southern New England buyers) showed that the project would likely create significant north and south transmission congestion, and might require significant backing down of existing Vermont renewable generation (for example, the McNeil biomass plant or existing hydro and wind plants). Bulk transmission projects that would deliver large volumes of power also have the potential to cause overloads on our subtransmission system, particularly under contingency conditions.

We expect that sponsors of bulk transmission projects delivering power into Vermont as well as proposers of significant generation projects that are proposed for the purpose of selling output to out-of-state buyers, will need to clearly demonstrate that their projects will be beneficial to Vermont electricity customers, taking into account grid impacts. This would presumably include detailed transmission system analysis to identify reasonably anticipated bulk transmission system congestion impacts, and the implementation of appropriate measures to mitigate them.

Future Vermont Generation

Other transmission system constraints could develop in Vermont over time, as additional distributed generation is deployed. In most cases, the initial limiting factor will be the distribution and subtransmission system (further discussed Chapter 6: Transmission and Distribution), however, enough distributed generation will eventually cause issues to arise on the bulk transmission system. To shed light on where and how such constraints might occur, VELCO's 2018 Long Range Transmission Plan (LRTP) explored Base and High Solar PV scenarios in which Vermont reaches a total of 500 MW to 1,000 MW of distributed solar generation, respectively, by the mid-2020s. While it appears that 1,000 MW substantially exceeds the volume of solar PV that will be deployed to meet the needs of Vermont customers by the mid 2020s, the VELCO analysis is instructive.

Under the High Solar PV case, VELCO's analysis indicated that this volume of additional distributed solar generation would overload some lines and transformers on the 115 kV system, with other areas of concern that include voltage regulation (pre- and post-contingency); overloads on subtransmission elements; and increasing system losses. Experience with the SHEI interface, along with insights from the VELCO LRTP, suggest that policies will need to be developed (or refined) to help address these considerations. For example, if the potential for transmission congestion is sufficiently understood, guidance or incentives with respect to the location of future distributed generation (and potentially load) might be developed to limit the degree to which transmission constraints are aggravated (or new ones created) by the deployment of additional distributed generation, and therefore the amount of grid investments and associated costs that must be incurred to mitigate those constraints. We are already encountering multiple instances where deployment of distributed generation is reaching export limits on the distribution system, the level at which locational guidance is needed first (as further discussed in Chapter 5: Our Increasingly Renewable Energy Supply).

The most appropriate forms of guidance are not yet certain, and will need to be developed thoughtfully. For example, VELCO notes that to limit future transmission system constraints, restrictions on growth of distributed generation in particular areas (for example, those that appear *likely* to trigger grid concerns) may not be as effective a strategy as directing generation toward areas that appear *unlikely* to aggravate such constraints. Further, VELCO analysis suggests that strategic location of distributed solar PV, the Vermont grid could accommodate over 1,000 MW of such generation. While this analysis focused only on transmission capacity, and other considerations such as siting and costs would need to be weighed, it hints at the potential to mitigate congestion on the transmission and subtransmission system through more strategic location of future distributed generation.

In addition to more strategic location of future generation, the occurrence and severity of transmission and distribution system constraints could potentially be mitigated by the deployment of battery storage in selected locations. Storage can act as a load during high distributed generation output times and the required inverter systems can also provide dynamic voltage support to mitigate adverse voltage performance on the transmission and distribution system.

Finally, in an environment of increasing renewable generation it appears appropriate to make future larger renewable generation sites dispatchable—that is, capable of turning down output automatically if and when needed—where this is practical. While it may seem counterintuitive to consider reducing output from a renewable power source with no fuel expense, this capability can be beneficial for our customers in some circumstances. For example, reduction of output during some conditions (very high local generation and low load) could conceivably help to avoid or limit anticipated distribution system overloading or transmission system congestion more cost effectively than an infrastructure investment. Similarly, the ability to temporarily reduce output from a renewable plant could be valuable during instances when LMPs are temporarily negative.[76] Pairing energy storage with these facilities can perform the same function without actually reducing the output of the facility.

ILLUSTRATIVE FUTURE PORTFOLIO

This section presents an illustrative future portfolio of supply resources, incorporating the observations and insights presented in this chapter. The illustrative future portfolio is "preferred" in the sense that it outlines the types of resources that we expect to explore or maintain in the next decade—including plausible types and amounts of resources that may be appropriate to help us meet the requirements of Vermont's RES program and manage wholesale market exposures—based on our current understanding of wholesale markets, customer preferences, and resource options. We do not appear to face any major portfolio deficiencies that require major long-term resource decisions or commitments at this time, or apparent "fork in the road" choices that would entail mutually exclusive resource options. This reflects the fact that our portfolio is more balanced and features more modest open positions than in the past, and many of the primary resource that we expect to pursue are relatively modular in scale and would be implemented over time in steps. The future portfolio is therefore illustrative in that it does not reflect any firm commitments, and the types and amounts of resources that we actually acquire could evolve over time in response to the factors and signposts outlined in this chapter.

There are several notable resource components of the Illustrative Future Portfolio.

Acquisition of additional distributed renewables over time, as needed to meet Tier II requirements including appropriate allowance for uncertainty of forecasted supply growth. Our base case assumptions do not show a need for new Tier II renewables in

76 See Chapter 3: Regional and Environmental Evolution, for a discussion of the increasing occurrence of negative energy pricing under ISO-New England's Do Not Exceed dispatch framework.

the near term, so we have not built explicit new distributed renewable additions into the portfolio model. But it seems clear that the timing and amount of potential need for additional distributed renewables could change based on the actual pace of growth of net-metered generation as well as Tier III supply in the coming years.

A limited mix of hydro (plant-contingent, or firmed) and offshore wind during the 2020s. The hydro resources could lock in a portion of our forecasted Tier I needs; the offshore wind could offer an attractive seasonal output profile and diversity from our other renewable resources. All three resources would have the potential to provide long-term portfolio cost stability after the expiration of major PPAs in the mid-2030s.

Acquisition of additional storage and flexible load resources. We assume that 50 to 100 MW of these resources will be deployed in our territory over the next decade, to address a mix of the potential use cases (as discussed in "Peaking and Flexible Load Resources" on page 8-32; and in Chapter 5: Our Increasingly Renewable Energy Supply). We recognize that the actual mix of resources, and the appropriate pace of deployment, is substantially uncertain and will depend strongly on several factors (including battery cost trends, customer needs for resiliency solutions, wholesale market price trends, among others) that will affect the cost-effectiveness of these resources and the scale of market for them.

Ongoing operation of our existing peaking plants. These plants rarely operate but do provide value as a significant capacity market hedge and potentially for local grid support. We recognize the fairly advanced age of our peaking fleet by assuming retirements of about 30 MW of peaking capacity during the planning horizon in the mid-2020s and early 2030s. Actual retirement decisions would, of course, be assessed on a plant-specific basis based on a range of factors (discussed in "Peaking and Flexible Load Resources" on page 8-32), so actual retirement dates are likely to differ significantly from the illustrative path presented here.

Manage short-term market price volatility through layered future purchases. We plan to continue managing our forecasted open positions through a series of layered short-term purchases of energy and capacity, typically for terms of less than five years. This strategy provides significant near-term price stability to our net power costs and retail rates, while in the longer term it retains a link to regional market prices and flexibility to acquire some amount of future resources that are not specifically anticipated today.

We have evaluated the Illustrative Future Portfolio using the attributes and metrics discussed throughout this chapter. Several of the attribute charts that were presented earlier in this chapter show very similar results for the Illustrative Future Portfolio. We therefore do not present all of the attribute charts again individually. The following results with respect to the Illustrative Future Portfolio are the most notable.

Attribute: Energy Open Position

Figure 8-19 shows a moderate open energy position during the 2020s, which is reduced gradually in the late 2020s as illustrative purchases from hydroelectric and offshore wind resources are phased in. These purchases would address strategic goals of locking in renewable supply and achieving greater long-term supply stability in the 2030s after the expiration of large existing PPAs.

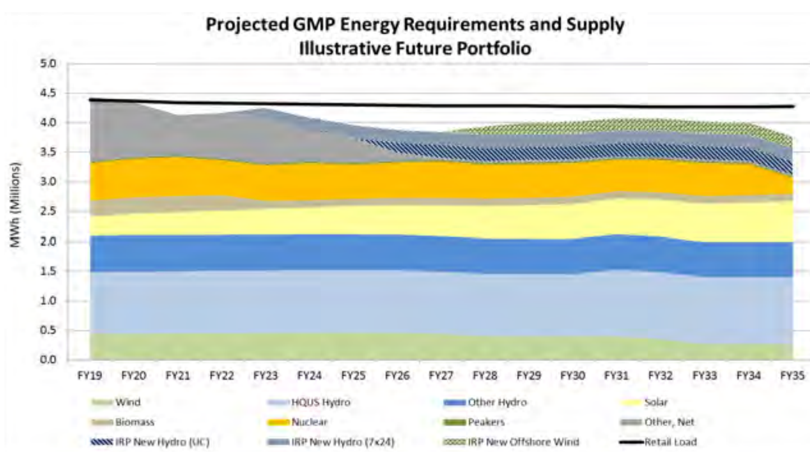

Figure 8-19. Projected Energy Requirements and Supply Preferred Portfolio

Figure 8-19 also illustrates how an increase in long-term supply in the late 2020s would further reduce our open position, and therefore the degree to which portfolio costs would follow regional market price trends. We expect that this tradeoff would be one of the factors to be considered in the evaluation of sizable additional long-term renewable sources like these.

Attribute: Capacity Open Position

Figure 8-20 shows a moderate open capacity position through the next decade, consistent with our strategy.

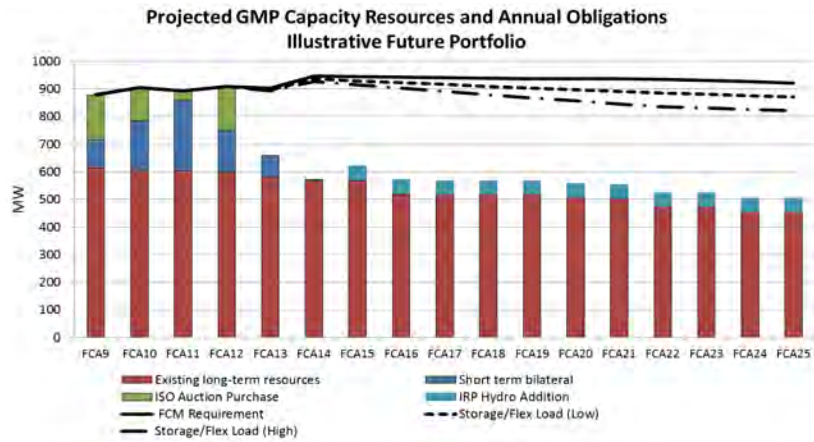

Figure 8-20. Projected Capacity Resources and Annual Obligations Preferred Portfolio

To manage exposure to year-to-year fluctuations in FCM clearing prices, we expect to continue to seek layered forward capacity purchases at stable or fixed prices. An illustrative path for deployment of storage and responsive load resources (discussed in "Peaking and Flexible Load Resources" on page 8-32) is illustrated here as a load reducer resource, with the benefit depicted by a dashed line reflecting lower capacity requirements achieved through peak reductions using these flexible resources.

Attribute: RES Tier I Gap Chart

Figure 8-21 illustrates how, as intended, the illustrative hydro purchases shown here would lock in a significant portion of our projected Tier I needs through the 2020s, while leaving a noticeable (but greatly reduced) fraction to be procured on a short-term basis.

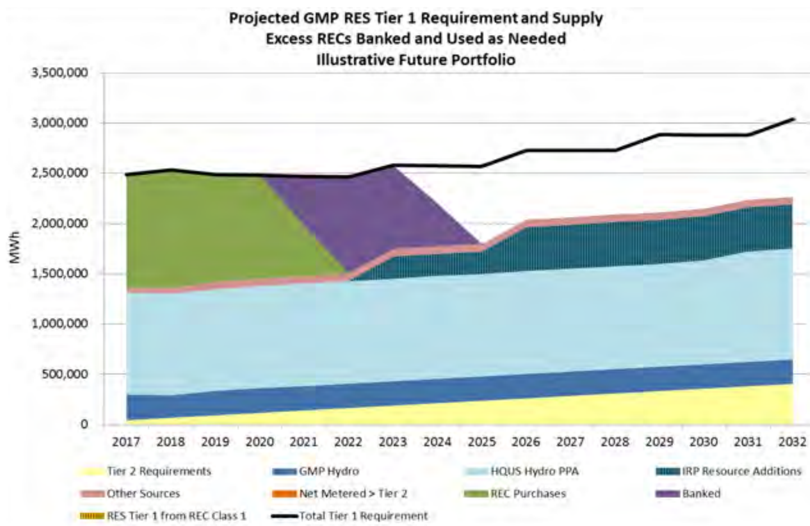

Figure 8-21. Projected Tier I Requirement and Supply Excess RECs Banked and Used Preferred Portfolio

Attribute: Portfolio Cost Sensitivity

Figure 8-22 illustrates the estimated sensitivity of our portfolio costs over the long-term to the high and low sensitivities for wholesale market prices for energy, capacity, and two types of renewable energy certificates, along with the future pace of growth of net-metered generation.

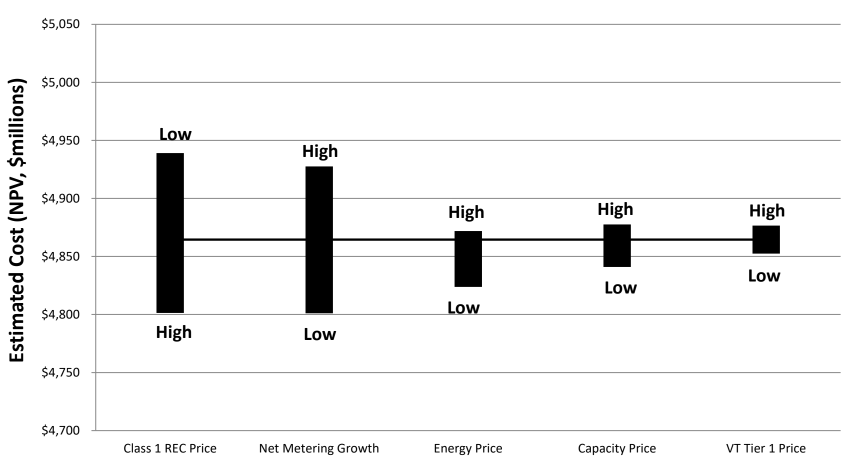

Figure 8-22. Tornado Chart for the Preferred Portfolio (Customer Costs)

Under base case assumptions, our estimated power and transmission costs through 2035 are on the order of $4.86 billion. Changes in these driving assumptions produce significant changes in the estimated costs, although those changes in the tens of millions of dollars are modest as a fraction of portfolio costs. This result is understandable as our portfolio is highly hedged in the first few years of the analysis, with limited open positions. Further, we have substantial long-term and stable-priced resources that protect against potential movements in energy and capacity market prices.

Class 1 REC prices have become a larger projected sensitivity than energy or capacity market prices. This is primarily because in New England it is not practical to hedge REC sales for delivery more than a few years into the future. As a result, most of our forward REC sales generally extend five years or less into the future, so our portfolio of salable RECs is more exposed to long-term market prices changes than are the energy and capacity components of the portfolio.

Finally, the sensitivity of portfolio costs to the future pace of net metering is considerable—comparable in impact to significant long-term changes in wholesale market prices. This is partly because the range of future net-metered growth tested here is quite large—from 10 MW to 30 MW per year, for many years. In addition, a substantial impact from net metering is not surprising because at present the effective price of net metering is substantial, and higher than the market value of net-metered output based on our current market outlooks.

Attribute: Greenhouse Gas Emission Profile

Figure 8-23 compares the projected emission profile of our portfolio to two regional benchmarks. Specifically, the dashed blue line depicts our projected average portfolio CO_2 emission rate for the Reference portfolio, while the purple dashed line depicts our projected emission rate for the Illustrative Future Portfolio.

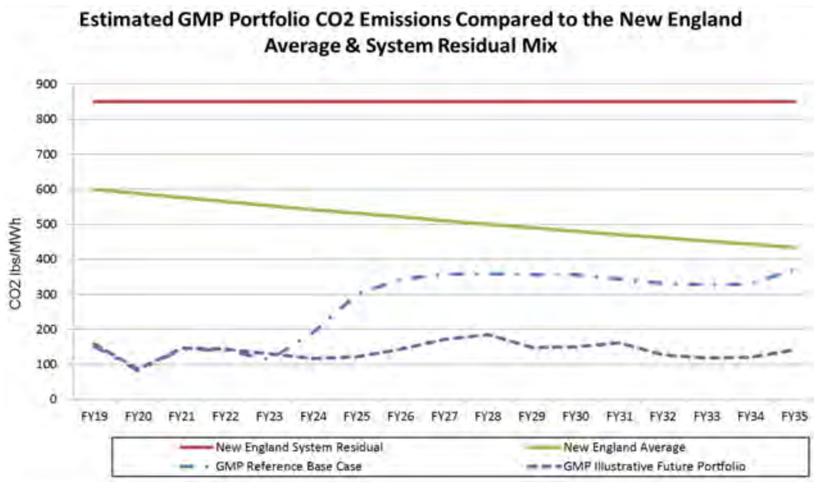

Figure 8-23. Estimated Portfolio CO_2 Emissions New England Comparison

The green line is a proxy for the ISO-New England System Mix, which includes all of the energy sources in New England, inclusive of imports from neighboring control areas.[77] We assume that the regional average emission rate will decline gradually over the planning horizon, as a result of efforts in neighboring states to lower their Greenhouse Gas (GHG) emission profiles. The red line is a proxy for the ISO-New England Residual System Mix, which includes all generation not specifically claimed and retired by market participants in the NEPOOL GIS, the region's database for tracking RECs and other generation attributes, for RPS compliance or other purposes. As a result, the Residual Mix contains the output of most of the region's fossil-fired generation fleet. In our portfolio evaluation, this is the rate assigned to the portion of our supply that is not met with generation attributes from other sources. The CO_2 emission rate shown here for the Residual Mix is higher than historically reported and we do not assume that this rate will decline over time. These assumptions reflect an expectation that increasing societal attention to greenhouse gas emissions could increasingly lead market participants to retire attributes from most non-emitting sources—leaving the residual mix increasingly reflecting the emission profile of gas- and oil-fired plants.

77 Reported average emissions in the NEPOOL Generation Information System (GIS) of roughly 900 pounds per MWh appear to be substantially affected by relatively small fractions of power from non-fossil fuel plants (such as biomass, trash to energy), suggesting that those rates might be overstated. We have therefore depicted regional average emissions at a lower proxy rate of 600 pounds per MWh. It is possible that this rate will turn out to be understated.

Our committed renewable supplies are sufficient to meet RES requirements through the early 2020s, but not in the long-term. As a result, our projected Reference portfolio emission rate in Figure 8-23 increases somewhat in the mid-2020s as current purchases of hydroelectric and nuclear generation attributes expire, but the core of low-emission sources keeps us somewhat below the regional average. In the Illustrative Future Portfolio, the acquisition of additional renewables over time—through a mix of plant-contingent hydro, firmed hydro, and market REC purchases—enables us to achieve the Tier I total renewable requirement, and significantly lowers our emission profile to a low fraction of the regional average.

Observations About the Illustrative Future Portfolio

Based on the resource additions and attributes, the following are notable observations about the Illustrative Future Portfolio:

- Our projected GHG emission profile is presently low relative to the New England region; it is projected to stay low over time in part because of achieving the increasing renewable requirements of the Vermont RES.
- The portfolio is fairly balanced, without extraordinarily large open positions. Our Tier I open position is relatively large, although the risk is somewhat limited in dollar terms.
- Based on the limited scale of open positions, and the fact that most of our sources are stable-priced, the sensitivity of our portfolio costs to alternative market prices (energy, capacity, regional Class 1 RECs, Tier I RECs) is moderate—and likely much less than for electric utilities and customers in neighboring states.
- Under base case assumptions, we are not projected to have a significant need for additional Tier II-eligible supply for a number of years. Low Tier III supply or low net metering growth in the coming years or both, could potentially change that assessment.
- Our portfolio is becoming more reliant on intermittent renewable resources over time; this can lead to short-term fluctuations in portfolio output and net power costs. This reliance is not a critical flaw, because such fluctuations tend to largely offset over time and there are potential tools to help manage them, but we are seeking additional portfolio modeling capability that may help us better understand and quantify this risk.

Finally, we plan to monitor a number of signposts that are potential leading or lagging indicators that could change some of our observations, or otherwise inform our future resource choices.

Summary of Metrics (Illustrative Future Portfolio)

The charts and narrative presented earlier in this section highlight the most notable attribute results for the Illustrative Future Portfolio. The "Evaluation of the Reference Portfolio" and "Sensitivity Analysis" sections provide valuable context that inform the portfolio. Table 8-4 and Table 8-5 present the estimated metrics under base case market assumptions on an annual basis.

	Flexibility			Cost		
Fiscal Year	Retail Sales (MWh)	Long-Term Resource %	Intermittent %	Net PP Costs ($ M)	Net PP & Tax Costs ($ M)	Average Portfolio Costs ($/kWh)
2019	4,156,468	77%	34%	$300	$415	$0.0999
2020	4,144,656	79%	36%	$305	$417	$0.1006
2021	4,120,065	80%	36%	$308	$421	$0.1022
2022	4,108,764	79%	37%	$305	$427	$0.1039
2023	4,097,182	81%	38%	$305	$432	$0.1054
2024	4,088,937	83%	39%	$316	$447	$0.1093
2025	4,079,429	83%	40%	$324	$458	$0.1122
2026	4,071,171	88%	44%	$336	$472	$0.1158
2027	4,066,829	90%	45%	$346	$483	$0.1188
2028	4,068,136	92%	49%	$359	$498	$0.1225
2029	4,066,874	93%	50%	$370	$512	$0.1260
2030	4,059,107	94%	51%	$380	$526	$0.1296
2031	4,054,489	95%	52%	$390	$539	$0.1329
2032	4,051,461	95%	51%	$393	$545	$0.1346
2033	4,050,516	94%	49%	$397	$553	$0.1364
2034	4,050,765	93%	50%	$404	$563	$0.1390
2035	4,052,243	88%	50%	$394	$556	$0.1372
NPV 2019–2035	42,249,337			$3,494	$4,866	

Table 8-4. Illustrative Future Portfolio (part one)

Fiscal Year	Carbon				Cost	Renewability		
	Portfolio CO_2 Emissions (pounds/MWh)	Percent of Regional System Mix	Portfolio CO_2 Emissions (Short Tons)	External Cost ($ M)	Total Cost with External ($M)	Tier I	Tier II	Total
2019	158	26%	346,607	$35	$450	58.0%	2.1%	60.0%
2020	87	15%	190,611	$19	$437	57.4%	2.7%	60.0%
2021	146	25%	320,384	$33	$455	56.8%	3.3%	60.0%
2022	143	25%	310,760	$33	$460	56.2%	3.9%	60.0%
2023	130	23%	279,745	$30	$462	57.8%	4.5%	62.3%
2024	117	22%	252,512	$28	$474	58.0%	5.1%	63.0%
2025	122	23%	261,721	$29	$487	57.4%	5.7%	63.0%
2026	143	27%	308,995	$35	$506	59.8%	6.3%	66.0%
2027	172	34%	371,762	$42	$526	60.2%	6.9%	67.0%
2028	186	37%	396,579	$46	$544	59.6%	7.5%	67.0%
2029	148	30%	317,140	$37	$549	62.0%	8.1%	70.0%
2030	149	31%	318,812	$38	$564	62.4%	8.7%	71.0%
2031	162	34%	343,201	$41	$580	61.8%	9.3%	71.0%
2032	126	27%	268,987	$32	$578	64.2%	9.9%	74.0%
2033	119	26%	252,173	$31	$583	65.0%	10.0%	75.0%
2034	121	27%	256,047	$32	$594	65.0%	10.0%	75.0%
2035	142	33%	303,486	$38	$594	65.0%	10.0%	75.0%
NPV 2019–2035	–	–	–	$327	$5,193	–	–	–

Table 8-5. Illustrative Future Portfolio (part one)

Estimated total portfolio costs over the analysis horizon is roughly $4.9 Billion present value; over 70% of this is projected power supply costs, with the remainder being transmission by others, primarily Regional Network Service. Most of the key metrics shown here (such as long-term resources and emission profile) are as presented earlier in this section.

Societal costs include power and transmission costs that our customers pay, along with the estimated external costs to society that are not already reflected or "internalized" in the market price of electricity. External societal costs associated with our portfolio are estimated based on the projected CO_2 emission profile of the portfolio, and a benchmark societal cost of $100/ton.[78] Because the CO_2 emission allowance prices incorporated in our base case market price forecast are much less than the $100/ton

78 Future societal cost of greenhouse gas emissions are uncertain and difficult to quantify; estimates vary widely. The $100 per ton amount used here is the same one that we used in its most recent IRP, and is consistent with the level presently being used in Vermont EEU screening of energy efficiency measures.

benchmark, there is a substantial external cost of emissions. As a result, the projected societal cost for the portfolio is more than $300 millon (or about %) higher than the direct customer cost. The projected emissions and societal costs associated with our portfolio over time are greatly limited by the subtantial and increasing RES requirements, along with the portion of our portolio from nuclear sources.

SIGNPOSTS

Beyond the direct market inputs and variables typically applied in the evalution of new resource additions, and against the backdrop of a rapidly evolving energy market, the portfolio evaluation helped to identify some additional factors that we expect to use to help guide resource decisions in the coming years. This approach introduces new threshold events or "signposts" to help inform and potentially narrow the list of resources that will brought into consideration for addition to the portfolio. In the application of signpost evaluation, our goal is to follow metrics that could be national, regional, or local—and tend to be rooted in the key energy transformation themes (described in Chapter 3: Regional and Environmental Evolution) indicating whether certain types of resources that may be needed or cost-competitive.

Table 8-6 presents a list of potential signposts that we expect to monitor in the course of evaluating future resource additions, and identifies the type of resources that could be informed by the signposts.

Indicator	Context	How This Indicator Could Inform Our Choices and Actions
GHG enacted & proposed emission regulation	National	Leading indicator of trends in electricity market prices, and relative price of electricity versus fossil fuels.
Frequency of extreme weather events	National & Regional	The value of resilience in our supply would be expected to grow with increases in event frequency, leading to more emphasis on reserves and supply that is less variable with the weather.
Growth of solar PV capacity in New England, and observed LMP value of solar PV output profile	Regional	Leading indicator of the value of output from additional solar PV sources.
Timing and shape of peak electricity demands (ISO-New England annual, Vermont monthly)	Local & Regional	Benefit and cost evaluation of potential battery storage and flexible load resources, for managing peak.
MW and MWh of battery storage deployed in the region	Regional	Leading indicator of potential trends in ISO-New England peak load profile, and potential supply saturation for the ISO-New England Frequency Regulation market.
Will battery storage systems paired with existing renewable systems be eligible for Federal investment tax credits?	National	Indicator of net cost to install battery storage at various locations in Vermont, with or without having to also install new renewables.
Pace of net metering applications and installations in our territory	Local	Leading indicator of how much Tier II-eligible supply we will acquire in the near future.
"Spread" of high and low hourly energy market prices (LMPs)	Regional	Benefit and cost evaluation of potential responsive load or battery storage resources. Also, directional guidance for operation of existing resources.
Energy market prices in winter versus other months	Regional	Indicator of the relative incremental cost of electricity to serve heating load vs. other types of electric load. Also, management of our winter net short energy position.
Relative prices of oil versus electricity	Local	Leading indicator of the future cost-effectiveness of electrification measures and customer adoption.
Our pace of completed Tier III transformation projects; pipeline for future projects	Local	Leading indicator that we might need to retire some Tier II RECs to cover a shortfall in Tier III supply. Also, an input to our retail sales forecast.
General inflation in the economy	National	An indication of portfolio cost trends, since some committed sources and open positions are directly and indirectly linked to inflation.

Table 8-6. Potential Signpost Indicators

National Indicators

For this category, we will be evaluating the larger transformative energy trends that have the broadest geographic implications. The most notable of these signposts will be the direction taken with the regulation of GHG and the policies that could emerge to address climate change. Metrics for this indicator would include the pace and evolutions of region efforts like Regional Greenhouse Gas Initiative (RGGI) in our region, and activities at the national level that increase the likelihood of new, meaningful policies to reduce emissions. In this example, to the extent that activity and data point to a likelihood of new regulations on the electric sector, we would use this indicator and more quickly advance the evalution of zero-carbon energy resources like those described in the preferred portfolio.

Regional Indicators

For these signposts the considerations are not as geographically wide as the national markers but they represent topics and considerations that could occur on a regional level to impact our resource decisions. This category of indicators can exist without being triggered by larger, nationwide trends and often the data collected will be related to the pace of change in New England. The most notable example of this type of indicator is the pace of solar PV installations in surrounding states. This growth has been extraordinary in the last few years and there are forecasts for rapid growth to continue. The actual pace at which this forecasted development occurs could have important implications for the value of future PV in our resource portfolio, and we would expect to use this indicator before pursuing additional PV resources.

Local Indicators

A number of the potential signpost indicators in the table are more specific to conditions that might be occurring in our service territory or within Vermont. Often this category of signpost will be oriented to tracking elements or trends in customer energy use or behavior that could have a direct bearing on the type of supply that might be best suited to address the trend. While local considerations are already a staple of the resource planning process, the overarching goal in this application will be to track items that might reveal the pace of transformation locally with examples being the pace of net metering applications or the pipeline of Tier III transformation projects.

MARKET PRICE INPUTS TO THE PORTFOLIO ANALYSIS

There are three major categories of market prices that we typically forecast: energy, capacity, and RECs. Energy and capacity are typically the two largest power supply cost categories, respectively; these feature markets that are managed by ISO-New England and can be viewed in the context of regional market dynamics for supply and demand and pricing. REC markets are driven more strongly by state RPS programs so although there is significant overlap across the states, significant supply and demand changes can occur based on legislative and regulatory changes to renewable policy at the state level. In general, market price expectations for these products are somewhat lower than in our 2014 IRP, although substantial uncertainty about future prices remains.

Energy Market

We developed our energy market price outlook starting with NYMEX-quoted energy futures for 5 MW blocks delivered at the Massachusetts Hub through 2022. These quotes generally reflect price levels at which we are able to transact arms-length energy purchases and sales.

Beyond the initial four year time horizon, energy prices are developed based on a number of factors that have historically been energy price drivers including anticipated New England load levels; anticipated generation additions and retirements; and future natural gas prices. Currently ISO-New England anticipates flat to slightly lower forecast loads over the next decade as shown in ISO-New England's Capacity, Energy, Loads, and Transmission (CELT) report. This is primarily driven by slow demand growth and the growth of behind-the-meter PV solar generation as well as continued energy efficiency initiatives.

There have been a number of significant retirements over the last several years including the 1,535 MW Brayton Point coal fired unit. In addition, Pilgrim (683 MW) will retire in 2019, Bridgeport Harbor (400 MW) anticipates retiring in 2021, and it is likely that Mystic Units 8 and 9 (1,744 MW) will retire in 2024. Additions include Towantic (801 MW natural gas) in 2018, Bridgeport Harbor (509 MW natural gas), and Canal 3 (342 MW natural gas) in 2019, followed by the New England Clean Energy Connect (1,200 MW) and offshore wind totaling 1,400 MW in 2023. Besides these large named projects, there are significant renewable additions anticipated based on various state RFPs over the last several years as well as more smaller behind-the-meter distributed generation projects. The addition of new, higher efficiency gas-fired units will have the near-term impact of pushing down the implied heat rate across New England, but we anticipate that this will be short-lived and that over the longer-term there will be a gradual increase in heat rates because of a number of factors including retirements of nuclear units and the need for rapid-ramping units as the growth of intermittent generation in the region continues.

New England natural gas prices are based on deliveries to Algonquin Citygate, which is not currently an actively traded NYMEX future contract. To develop an outlook for Algonquin Citygate, we rely on the historical basis differential between spot prices for deliveries of natural gas at Algonquin Citygate and at the Henry Hub, which is a commonly quoted pricing point for natural gas in North America. We used this historical relationship, along with NYMEX futures for natural gas delivered at the Henry Hub in Louisiana (NG), to derive anticipated futures prices for Algonquin Citygate.

Over the longer term, the energy model reflects a number of adjustments to more accurately reflect anticipated market dynamics. First, futures for natural gas delivered at the Henry Hub are relatively thinly traded after the first few years; we adjusted them reflect fundamentals-based considerations underlying the Energy Information Agency's 2018 Annual Energy Outlook (AEO) report and the 2018 Synapse Avoided Energy Supply Components in New England (AESC) report. These consideration include anticipated drilling activity; higher breakeven drilling and operating costs; anticipated LNG exports; and growing domestic natural gas demand. In addition, we reduced the basis differential between Henry Hub and Algonquin Citygate in the 2020s to reflect the anticipated moderating influence during winter months of new non-gas sources like the (NECEC) transmission line from Québec and offshore wind generation, which should displace some gas-fired generation and help to decrease the number of winter hours that experience significant natural gas constraints. Finally, some additional upgrades to existing pipeline capacity and the addition of new pipeline capacity into New York and the Mid-Atlantic region should help to free up some incremental natural gas for New England during normal conditions.

The forecast also assumes that there will be some modest incremental carbon priced into New England energy prices to reflect changes to the RGGI and potential future carbon initiatives in the region. These assumptions are reflective of RGGI prices growing to about $10/short ton by 2026 and continuing to grow slowly through 2030 based on the August 2017 RGGI model rule. If tighter new regulation of greenhouse gases were introduced on a national or regional level, significantly higher allowance price and energy market price outcomes could result.

For the Low Energy Market Price scenario, we assume that market prices are 5% lower than in the base case, and that from 2030 forward market prices turn out 15% below the Base Case. This scenario is consistent with a future in which natural gas prices turn out lower than presently anticipated (because of lower extraction costs nationally; additional pipeline capacity or LNG deliveries into New England) or the implied market heat rate[79] turns out lower (because of substantial offshore wind development displacing the need for some thermal generation; lower regional electricity demand). This scenario also assumes that there is a limited push for internalizing carbon into energy pricing, CO_2 allowance pricing following the base case growth rate until 2030, after which it would grow at a slightly slower pace ending at $7.03/short ton in 2035.

Finally, the High Energy Market Price Scenario assumes that energy market prices turn out 5% higher than in the base case, and 15% higher from 2030 forward, because of higher natural gas prices and/or an increase in the implied market heat rate. These higher price outcomes could be driven by delays in additional pipeline capacity projects into New York and the Mid-Atlantic states; delays in the proposed NECEC or offshore wind projects; or increasing demand. In addition to this higher pricing environment, the High Energy Market Price scenario assumes more rapid increases in the pricing of CO_2 in the electricity market, through coordinated state action or a new national policy. The projection assumes internalized CO_2 pricing will resemble Synapse's 2016 Low Case in real dollars per short ton, starting at around $0.65/short ton in 2023 and rising to about $18.62/short ton in 2035. As a result of higher emission pricing, the "upside" market price exposure in the High Energy Market Price scenario is somewhat lower than the "downside" price exposure in the Low Energy Market Price scenario.

Figure 8-24 illustrates the resulting Base, High, and Low energy market price outlooks for round-the-clock ("7x24") energy delivered at the Mass Hub.

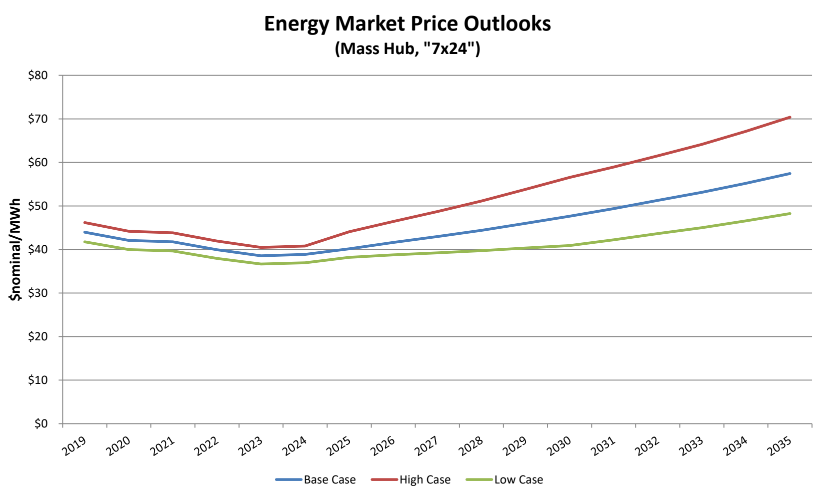

Figure 8-24. Energy Market Price Outlooks

79 An implied market heat rate reflects the ratio between electricity market prices and natural gas prices to power plants at a particular location.

Capacity Market

The FCM is the market-based mechanism used by ISO-New England to ensure that sufficient capacity resources will be in place to meet projected resource adequacy requirements. Annual FCAs are conducted for the delivery of capacity about three years in advance of each capacity year. The auction clears at the marginal price at which sources of capacity like supply, demand side sources, and imports from outside New England, are willing to meet ISO-New England's need for capacity. Capacity market prices are driven by the supply and demand of capacity resources, and the prices at which they are willing to commit to supply capacity. Some auctions have yielded unique clearing prices for capacity zones that are import or export-constrained. Load-serving entities like GMP are responsible for a share of the capacity that ISO-New England purchases each year that are allocated based on their respective contribution to the ISO-New England annual peak load. This obligation may be met using owned or purchased capacity resources, or through payments to ISO-New England.

The capacity price forecast is based on an understanding of the FCA structure, current assumed plant additions, and current assumed plant retirements. The last auction (FCA #12) cleared at $4.63/kW-month because two large natural gas plants (Mystic 8 and Mystic 9) were not allowed to delist because of ISO-New England reliability concerns. Had these two units been allowed to delist the auction would have stopped somewhere between the two units' delist bids which were both above $5.00/kW-month.

Our current assumption is that the two units, totaling over 1,700 MW of nameplate capacity, will now retire in 2024. Beginning with FCA #13 which will be held in February 2019, there are several changes to the auction that will likely affect clearing prices. These include lowering the dynamic delist threshold for $5.50/kW-month to $4.30/kW-month; the implementation of Competitive Auctions for Sponsored Policy Resources (CASPR) where ISO-New England will conduct a "substitution auction" after the primary FCA to allow new state-sponsored resources that did not clear the primary FCA to obtain the Capacity Supply Obligation (CSO) awarded to units wishing to retire but that retained a CSO in the primary FCA; and finally a sustained drop in ISO-New England's peak load forecast. These factors should, all other things being equal, tend to moderate the auction clearing prices over the next several auctions.

We are currently projecting that the next three auctions will be slightly above the $4.63/kW-month clearing price featured in FCA #12 before beginning a gradual upward slope to a point at which it will be about 20% lower than the Net Cost of New Entry (Net CONE) at the same time we have moderated our inflation assumption for Net CONE to reflect a 2% historical inflation rate, rather than the slightly higher than inflation 2.5% assumption that we had previously used.

The major forces that this forecast tries to balance are the influx of new renewable generation under various state RFPs and other programs, with the need to maintain fossil generation to help manage the intermittency of these new sources. The interplay of these two forces will likely moderate the upward slope of the price curve, but will also limit the downward price pressure as the current low energy price environment makes it difficult for relatively high priced units that are called to run infrequently to remain financially viable without some reasonable level of capacity or other ancillary revenue source. This forecast assumes that there will be a rough balance between retiring and new resources that will provide a reasonable pricing floor, but that retirements of units that are slow ramping and have long minimum runtimes will begin in the late 2020s, leading to higher prices to incent new entrants.

The Low Capacity Market Price scenario assumes that marginal units are able to continue operating into the 2030s before they delist and that higher capacity factors for renewables such as offshore wind help to minimize the need for new fossil generation. Another important assumption is that technological advances help to hold down the cost of replacement units, meaning that these generators will need lower capacity payments to be financially viable. In this scenario there is a movement to using battery storage for capacity resources, based on a four-hour or longer battery configuration that will help to displace peaking units.

The High Capacity Market Price scenario assumes that a large number of generators with undesirable attributes such as slow ramp rates, long minimum runtimes, and limited starts per day, begin to delist sooner because of the mix of low capacity prices and low energy prices. Once these marginal units have delisted, ISO-New England will need significant additional new generation to help manage intermittency, including fast ramping units to help manage output shifts from large renewable generation (for example, 1,400 MW of offshore wind). This scenario assumes that prices for battery storage drops at a slower than anticipated rate and the units remain expensive relative to other fast-ramping generation.

Figure 8-25 illustrates the resulting Base, High, and Low price outlooks for the ISO-New England FCM.

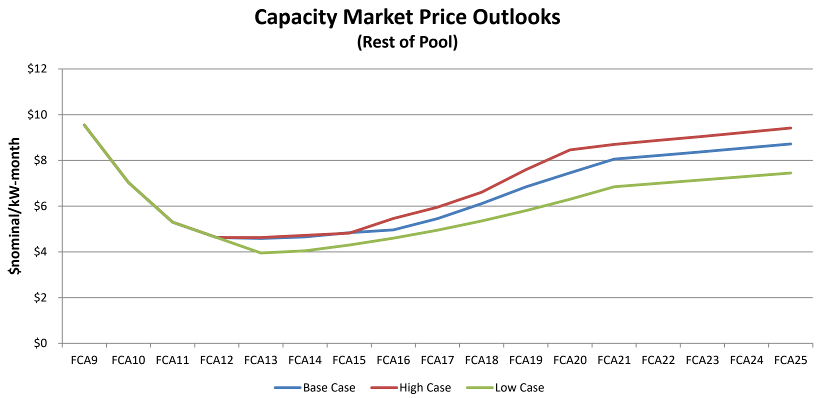

Figure 8-25. Capacity Market Price Outlooks

Renewable Attributes and RECs

Each of the New England states has either a RPS or, in Vermont's case, a RES, that mandates renewable energy purchases by type and volume. Renewable generation resources can qualify for participation in multiple state programs, but the underlying generation can only be counted once for purposes of meeting a specific utility's obligation. A REC is a claim to the attributes of one MWh of renewable generation. RECs can be bought and sold either bundled with the underlying energy or separately as a claim to the renewable attributes of the generation.

Certain RECs associated with our generation that qualify for Tier I in Vermont based on such factors as the project's size or the date that it reached commercial operation may also qualify for participation in another state's RPS—typically Class 1 in Massachusetts and Connecticut. There is substantial overlap between the Class 1 RPS eligibility requirements in the New England states, like wind and solar PV generation tend to qualify in all of them, so this outlook addresses trends for these market as a whole.

The outlook for regional Class I REC value is driven by the balance of demand that is driven by policy and the available supply. The New England market has swung toward a surplus in recent years, driven by a combination of substantial distributed renewables and state-supported solicitations for long-term renewable PPAs. This balance appears unlikely to change fundamentally any time soon, although parallel requirements of the Massachusetts Clean Energy Standard appear to provide some price support in the near-term, before anticipated low-emission imports over the proposed NECEC line in Maine arrive.

Based on this situation assessment, regional Class I REC market prices are assumed to increase modestly to about $17/MWh in 2021, before trailing off to around $15/MWh through 2030. In a Low Class 1 REC Price scenario, reflecting a more extreme and sustained regional surplus, these RECs would only increase to $10/MWh and then slow drop to $5/MWh for the long-term. In a High Class 1 REC Price scenario, which would be consistent with slower renewable development and a greater level of attrition from some renewable supplies (for example, imports from neighboring control areas, existing biomass plants), prices are assumed to increase to $25/MWh and hold steady until 2030, reflecting tight supply.

Figure 8-26 illustrates the resulting Base, High, and Low price outlooks for regional RPS Class 1 RECs.

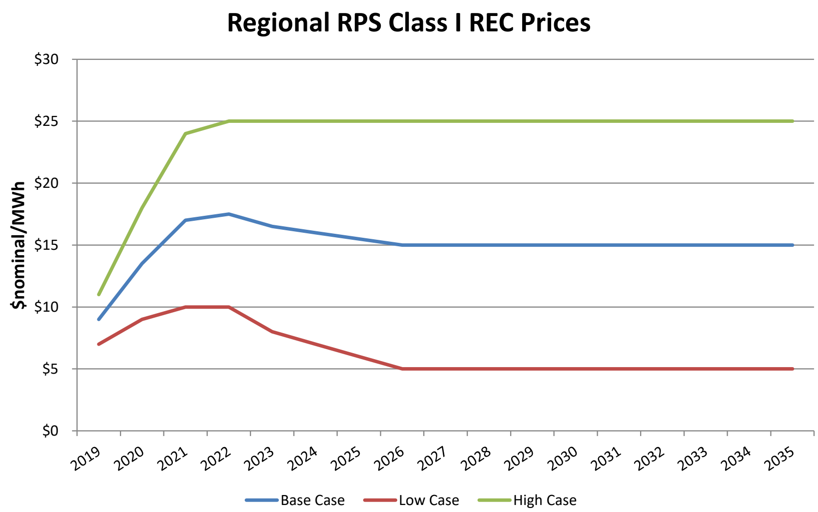

Figure 8-26. Regional RPS Class I REC Prices

Vermont RES Tier I features a much wider range of renewable resource eligibility than the regional Class 1 markets, so this is presently a relatively large volume, low-priced market. Factors that could lead to a tightening supply and demand balance and higher prices include temporary variations in renewable output; policy changes in neighboring states that increase demand; the growth of Vermont's Tier I obligation over time; and voluntary demand on the part of businesses and institutions. We also observe that ownership of existing renewables in the region is relatively concentrated, and attrition of some smaller, higher-cost existing renewable units also seems possible in light of the low energy and capacity environment.

Figure 8-27 illustrates the resulting Base, High, and Low price outlooks for Vermont Tier I RECs.

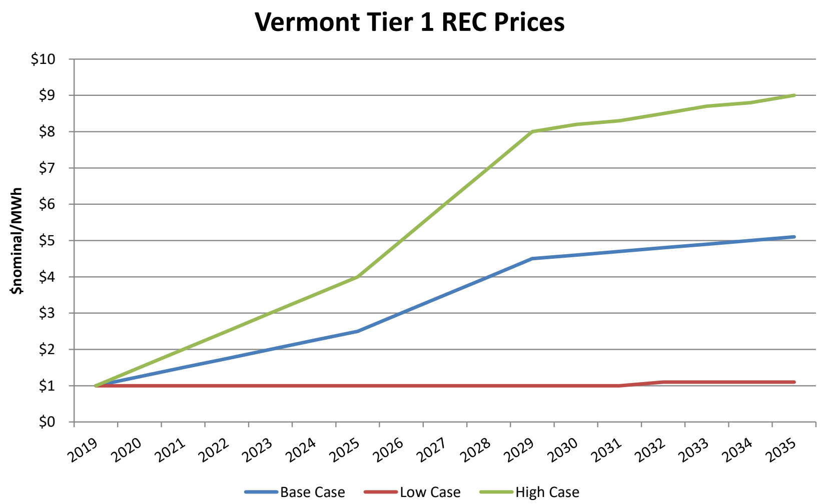

Figure 8-27. Vermont Tier I REC Prices

In light of these forces, the Base Tier I REC price outlook grows gradually from $1/MWh to around $5/MWh by 2030. For the Low Tier I REC price future we assume that the Tier I price remains at about $1/MWh through 2030, while the High Tier I REC price future has the price growing more rapidly and reaching about 60% of anticipated ACP by 2030 at about $8 per MWh.