

5. Our Increasingly Renewable Energy Supply

Our electricity load obligation (retail electricity consumption minus distribution and transmission grid losses) is met almost fully from energy from power purchase agreements (PPAs) and output from units that we wholly or partially own.

This portfolio of resources has undergone a substantial transformation in the past decade, as the two largest sources that supplied the bulk of our power needs—long-term PPAs from Hydro-Québec and the Vermont Yankee nuclear plant—ended and have been replaced with a more diverse mix of resources that includes more utility scale renewable power sources; a somewhat smaller long-term purchase from Hydro-Québec; a smaller long-term nuclear purchase backed by the Seabrook plant in New Hampshire; and extraordinary growth of distributed renewable generation in our service territory.

Our present portfolio is more flexible because not all of our supply is committed to long-term sources. By design, a portion of the portfolio is presently obtained through layered energy and capacity market purchases of up to five years in duration.

CURRENT SUPPLY RESOURCES

Our power supply resources include output from facilities at various locations across Vermont and New England, along with market-based purchases that are generally short term (five years or less). Most of our supply comes from PPAs; roughly 20% is obtained from GMP-owned sources.

Table 5-1 summarizes our resource mix.

Ownership	Subtype	Generator
Owned Generation	Jointly Owned	McNeil, Millstone 3, Stony Brook, and Wyman
	Wholly Owned	Our hydroelectric, oil-fired, solar and wind generators
Power Purchase Agreements	Long-Term Units	NextEra Seabrook; Granite Reliable Wind; Deerfield Wind; Moretown Landfill; Ryegate biomass; Stony Brook combined cycle; Joint Venture solar (Hartford, Panton, Williston, Williamstown, and Richmond); Sheldon Springs hydro; North Hartland Hydro; Ampersand Gilman hydro; Lower Village hydro; and nine small solar projects (ranging from 1 MW to 5 MW)
	Long-Term System	HQ-US long-term PPA
	Short-Term Unit	Boltonville hydro
	Short-Term Market	Macquarie, Shell, Citigroup, BP, and NextEra energy contracts
	Standard Offer	Primarily solar PV; also biomass, farm and landfill methane, hydro and wind—all from projects up to 2.2 MW
	Vermont Electric Power Producers Inc.	Vermont's Qualified Facilities (Hydro) under Vermont's PURPA implementation also known as Rule 4.100
Net-Metered Generation	Under PUC Rule 5.100	Overwhelmingly solar PV; projects are generally sized from a few kW up to 500 kW. ⁴² They serve to reduce our retail sales and reduce requirements from other wholesale power sources.

Table 5-1. Total General Supply

Major owned generation resources include 44 hydroelectric, 12 solar, six oil-fired, and two wind projects. PPAs currently include twenty-four long-term contracts, six short-term contracts, and several renewable sources that are credited to our supply portfolio by statute.

⁴² By statute, a small number of larger projects (for example, solar PV located at closed landfills or military facilities) are also eligible for net metering.

Figure 5-1 depicts our energy supply for calendar year 2017 *before* the purchase and sale of renewable energy certificates.

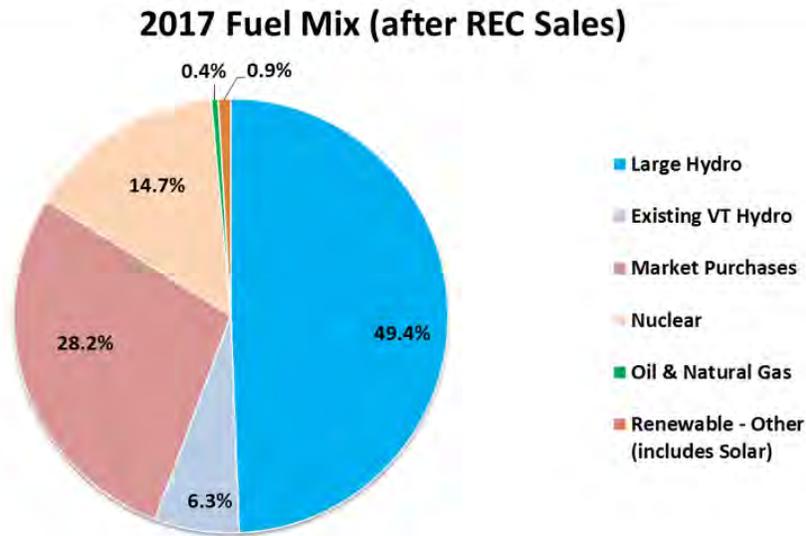


Figure 5-1. Fuel Mix Before Accounting for REC Transactions

Figure 5-2 depicts our energy supply for calendar year 2017 *after* the purchase and sale of renewable energy certificates.

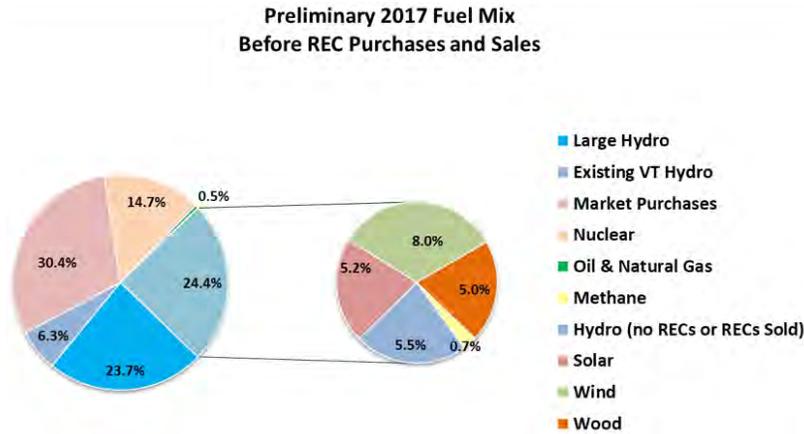


Figure 5-2. Fuel Mix After Accounting for REC Transactions

5. Our Increasingly Renewable Energy Supply

Current Supply Resources

Owned Hydroelectric Generation

We currently operate 44 hydroelectric generators: 32 are legacy systems and 12 were recently acquired from Enel. Table 5-2 summarizes our legacy hydroelectric plants.

Unit	Age (years)	Type	MW	Unit	Age (years)	Type	MW
Arnold Falls	90	Run-of-River	0.35	Middlebury Lower	98	Run-of-River	2.25
Beldens Falls	105	Run-of-River	5.85	Middlesex #2	90	Run-of-River	3.20
Bolton Falls	32	Run-of-River	7.50	Milton	89	Dispatchable	7.50
Carver Falls	124	Run-of-River	2.55	Passumpsic	90	Run-of-River	0.70
Cavendish	110	Run-of-River	1.44	Patch	97	Run-of-River	0.40
Center Rutland	120	Run-of-River	0.28	Peterson	70	Dispatchable	6.35
Clarks Falls	81	Dispatchable	3.00	Pierce Mills	90	Run-of-River	0.25
East Barnet	35	Run-of-River	2.20	Proctor	113	Dispatchable	10.23
East Pittsford	104	Dispatchable	3.60	Salisbury	101	Dispatchable	1.30
Essex #19	101	Run-of-River	7.20	Silver Lake	102	Dispatchable	2.20
Fairfax Falls	98	Run-of-River	4.20	Smith	34	Run-of-River	1.50
Gage	99	Run-of-River	0.70	Taftsville	76	Run-of-River	0.50
Glen	98	Dispatchable	2.00	Vergennes A&B	106	Run-of-River	2.40
Gorge #18	90	Run-of-River	3.00	Waterbury #22	65	Run-of-River	5.52
Huntington Falls	107	Run-of-River	5.50	West Danville #1	101	Run-of-River	1.00
Marshfield #6	91	Dispatchable	5.00	Weybridge	67	Dispatchable	3.00
Total							102.67

Table 5-2. Legacy Hydroelectric Resources

Table 5-3 summarizes the hydros we have recently acquired from Enel.

Unit	Age (years)	Type	MW	Unit	Age (years)	Type	MW
Barnet	32	Run-of-River	0.56	Ottauquechee	94	Run-of-River	1.69
Deweys Mill	33	Run-of-River	2.75	Rollinsford	35	Run-of-River	1.50
Kelley's Falls	29	Run-of-River	0.40	Salmon Falls	95	Run-of-River	1.20
Lower Valley	111	Run-of-River	0.92	Somersworth	34	Run-of-River	1.28
Mascoma	30	Run-of-River	2.05	West Hopkinton	35	Run-of-River	1.12
Newbury	14	Run-of-River	0.42	Woodsville	94	Run-of-River	0.36
Total							14.25

Table 5-3. Hydroelectric Resources Acquired from Enel

Our 44 hydroelectric generators are capable of generating almost 117 MW of electricity and produce an average of about 390,000 MWh of energy each year. These resources provide approximately 63 MW of FCA-based capacity credit and additional seasonal capacity payments.

Collectively, our fleet of owned hydroelectric plants generates an average of roughly nine percent of our annual energy requirements. The output of the hydroelectric plants can vary significantly on a daily, monthly, and annual basis depending on the actual flow of the rivers where the plants are located. Although these plants require regular operation and maintenance expenses, along with periodic capital expenditures for major improvements (and periodic FERC relicensing), they are the longest-lived assets in the supply category and, on average, the cost of power from our hydroelectric fleet is moderate and relatively stable. The hydroelectric plants incur no fuel expenses so the output helps to stabilize our power supply costs and retail rates, and they do not emit greenhouse gases. All hydroelectric plants are eligible to help us meet our RES Tier I renewable requirements. Some plants are also eligible to comply RPS markets in neighboring states (primarily Massachusetts Class 2); we therefore have the option to sell some or all of the RECs from these plants (with the revenues used to reduce net power costs and retail rates).

Legacy Hydroelectric Fleet

Here is a plant-by-plant summary of our legacy hydroelectric fleet, including license status and major improvements that have been completed or are in progress. Seven hydro plants (with a collective capacity of about 17.3 MW) are scheduled for FERC license renewals by 2024.

Arnold Falls. A run-of-river facility located on the Passumpsic River in Saint Johnsbury.

Operational License: FERC 40-year license No. 2396 that expires June 16, 2034.

Recent Improvements: In 2008, we modernized the facility's switchgear, relay protection, and controls; in 2009, we constructed a new concrete gravity dam to replace the dam's deteriorated timber cribs.

Beldens Falls. Run-of-river facility located on Otter Creek in New Haven. Central Vermont Public Service (CVPS) acquired this former Vermont Marble Power Division (VMPD) facility in 2011.

Operational License: FERC 40-year license No. 2558 that expires in 2054.

Recent Improvements: In 2008, we modernized the station's electrical switchgear, protection relays, and control devices; refurbished turbine-generator Unit 2; and completed FERC-required recreational improvements and runner upgrades for Unit 3.

Bolton Falls. Run-of-river facility located in Duxbury.

Operational License: FERC 40-year license that expires January 31, 2022.

Recent Improvements: Originally built in 1899, we rebuilt it in 1985 and again in 2005. We also modernized the station's electrical switchgear, protection relays, automation, and control devices.

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Carver Falls. Run-of-river facility located on the Poultney River in East Hampton, New York and West Haven, Vermont.

Operational License: FERC 30-year license No. 11475 that expires in 2039.

Recent Improvements: In 2011, we replaced and uprated turbine-generator Unit 1.

Cavendish. Run-of-river facility located in Cavendish.

Operational License: FERC license No. 2489.

Recent Improvements: Since the unit was commissioned, we installed an automated spillway crest control at the dam.

Center Rutland. Run-of-river former VMPD facility (acquired by CVPS in 2011) located in Rutland on Otter Creek.

Operational License: FERC 30-year license No. 2445 that expires in 2024.

Recent Improvements: Recently, we added relay protection and SCADA controls to improve remote operation, and refurbished major mechanical components to enable the hydro to be brought back online.



Figure 5-3. Clarks Falls Hydro, Milton

Clarks Falls. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.

Operational License: FERC 30-year license No. 2205 that expires in 2035.

Recent Improvements: In 2001, we installed a new generator step-up transformer; in 2004, we replaced the turbine runner.

East Barnet. Run-of-river facility on the Passumpsic River in Barnet.

Operational License: FERC Exempt No. 3051.

Planned Improvements: We plan to improve the communication network.

East Pittsford. Dispatchable facility located on East Creek in Pittsford; one of two facilities that comprise the North Rutland Composite. Because of the size and hazard classification of the Chittenden Dam, which forms the station's impoundment, this facility falls under the Vermont Public Service Board's (PSB's) dam safety regulation.

Operational License: Non-FERC jurisdiction.

Recent Improvements: In 2010, we modernized the station's switchgear, protection relays, and control devices; replaced the penstock in the powerhouse; automated critical equipment, including the head gate; and refurbished the major penstock.



Figure 5-4. Essex #19 Hydro Station

Essex #19. Run-of-river facility constructed in 1917 located on the Winooski River in Williston and Essex Junction.

Operational License: FERC 30-year license that expires on March 30, 2025.

Recent Improvements: In 1990, we significantly repaired the dam. More recently, we continued to resurface the concrete dam, replaced the GUS

Transformer, upgraded the exciters, and replaced two of the three rubber bladders.



Figure 5-5. Fairfax Falls Hydro Turbine Generators

Fairfax Falls. Run-of-river facility located in Fairfax, on the Lamoille River.

Operational License: FERC 30-year license No. 2205 that expires in 2035.

Recent Improvements: In 2004, we modernized the station's electrical switchgear, protection relays, and control devices; and refurbished and uprated turbine-generator Unit 1;

refurbished the Unit 2 generator and stator; and replaced the waste gate.

Gage. Run-of-river facility located on the Passumpsic River in St. Johnsbury.

Operational License: FERC 40-year license No. 2397 that expires 2034.

Recent Improvements: We replaced the original head gates and actuators with new steel gates and automated actuators, made safety improvements, and resurfaced the concrete on the intake canal.

Glen. Dispatchable facility located in Rutland, on East Creek; one of two facilities that comprise the North Rutland Composite.

Operational License: Non-FERC jurisdiction.

Recent Improvements: We modernized the station's electrical switchgear, protection relays, and control devices; installed a new generator step-up transformer; replaced sections of the penstock; rewound Unit 1; performed environmental abatement in the powerhouse; replaced over 2,000 linear feet of penstock; replaced the trash racks and head gate actuator; modernized the station's switchgear, relay protection, and controls; installed a new generator step-up transformer; and replaced penstock sections.

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Figure 5-6. Gorge #18 Hydro Facility

Gorge #18. Run-of-river facility located in Colchester and South Burlington.

Operational License: Non-FERC jurisdiction.

Recent Improvements: Gorge’s two dams were built in 1914 and 1928. Recently, we installed a new runner to capture lower flows and an automated crest control rubber dam system. These improvements are expected to significantly increase the station’s capacity of approximately 9,500 to 11,500 MWh per year.

Huntington Falls. This former VMPD run-of-river facility is located on Otter Creek in Weybridge.

Operational License: 40-year FERC license No. 2558 expires in 2054.

Recent Improvements: In 2015, we refurbished and uprated the turbine-generator on Unit 1 and Unit 2 (the turbine-generator on Unit 3 operates well and is in good repair), modernized the electrical system, and automated the plant.

Marshfield #6. Dispatchable facility located in Cabot. The dam is a rolled earth-fill construction built in 1927 with an additional spillway added in 1991. Because of the size and hazard classification of the Marshfield Dam, this facility falls under the PSB’s dam safety regulation.

Operational License: Non-FERC jurisdiction.

Recent Improvements: We replaced the wood-stave penstock over a six-year timeframe, modernized the electric system, rebuilt the substation, resurfaced the concrete, and replaced the head gate. We plan to improve the dam infrastructure and make safety improvements; we are currently involved in Chapter 43 proceedings to gain approval for these upgrades.

Middlebury Lower. Run-of-river facility located on Otter Creek in Middlebury.

Operational License: FERC 30-year license No. 2737 that expires in 2031.

Recent Improvements: In 2004, we modernized the electrical relay protection relays and control devices; in 2010, we installed a new generator step-up transformer. More recently, we made building improvements, and rewound the generator. We plan to resurface the concrete and potentially rebuild Unit 1 and Unit 2, both recommended by FERC.

Middlesex #2. Run-of-river with minimal ponding facility located in Middlesex was originally built in 1928.

Operational License: Non-FERC jurisdiction.

Recent Improvements: We reconstructed the intake canal and headworks, and replaced the original turbine runners.



Figure 5-7. Milton Hydro Plant

Milton. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.

Operational License: FERC 30-year license No. 2205 that expires 2035.

Recent Improvements: In 2002, we modernized the station's electrical system; in 2005, we installed an automated spillway crest control; and in 2007, we reconstructed the intake and headworks. More recently, we upgraded the governor controls and resound the generator.

Passumpsic. Run-of-river facility located on the Passumpsic River in St. Johnsbury.

Operational License: FERC 40-year license No. 2400 that expires in 2034.

Recent Improvements: We improved the fish passage and resurfaced the concrete.

Patch. A run-of-river facility located on East Creek in Rutland.

Operational License: Non-FERC jurisdiction.

Recent Improvements: In 2011, Hurricane Irene significantly damaged the Patch station and flooded the plant. We thoroughly cleaned and replaced many electrical components, including a full rewind of the generator, and brought the unit back online in 2013.

Peterson. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.

Operational License: FERC 30-year license No. 2205 that expires in 2035.

Planned Improvements: In 2019, we plan to start a major mechanical and electrical modernization project to improve safety, operations, and reliability.

Pierce Mills. Run-of-river facility located on the Passumpsic River in St. Johnsbury.

Operational License: FERC 40-year license No. 2396 that expires in 2034.

Proctor. Dispatchable former VMPD facility (acquired by CVPS in 2011) located on Otter Creek in Proctor.

Operational License: FERC 40-year license issued in October 2014.

Recent Improvements: We have fully restored this facility. In 2012, we built a vehicular

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bridge that spans Otter Creek at the station; in 2013, we extensively modified the intake headworks. After receiving authorization from FERC in 2014, we began modernizing the mechanical and electrical systems, and adding a new turbine-generator for increasing capacity. After FERC issued a new operating license in October 2014, we completed the work started earlier in the year: we replaced three turbine-generator sets and completely overhauled and rebuilt another turbine-generator unit. The facility became fully operational in the second quarter of 2015. In 2016, we completed FERC-required recreational improvements.

Salisbury. Dispatchable facility located on the Leicester River in Salisbury; one of three facilities that comprise the Middlebury Composite.

Operational License: Non-FERC jurisdiction.

Recent Improvements: In 2011, we modernized the station's electrical switchgear, protection relays, and control devices; installed a new generator step-up transformer; and recoated sections of the penstock pipeline.

Silver Lake. Dispatchable facility located on the Sucker Brook in Leicester; one of three facilities that comprise the Middlebury Composite.

Operational License: FERC 30-year license No. 11478 that expires in 2039.

Recent Improvements: In 2008, we improved the stability of the Goshen and Silver Lake dams to meet FERC dam safety guidelines. In 2011, we automated the station components. We are currently underway with a large capital project to complete final dam safety improvements at the Goshen Spillway, which we expect to complete by 2020.

Smith. Run-of-river facility located on the Waits River in Bradford.

Operational License: FERC Exempt No. 3051.

Recent Improvements: In 2006, we replaced the Unit 1 turbine runner. More recently, we replaced the taintor gate control and a gearbox for Unit 2.

Taftsville. Run-of-river facility located on the Ottauquechee River in Woodstock.

Operational License: FERC 30-year license No. 2490 that expires in 2024.

Recent Improvements: In 2011, the Taftsville facility flooded extensively during Hurricane Irene. Since then, we cleaned up the site, modified the powerhouse, modernized the electrical equipment, and replaced the station's electrical switchgear, protection relays, and control devices, and its generator rewind.



Figure 5-8. Vergennes Hydro Facility

Vergennes. Run-of-river facility with limited storage capacity located on Otter Creek in Vergennes.

Operational License: FERC 30-year license that expires on May 31, 2029.

Recent Improvements: In 2010, we completely rebuilt the intake system, associated penstocks, and turbines of Units 1 and 2. Currently, we are replacing the penstock to Unit 9b. In 2019, we plan to modernize the

station's electrical system with new switchgear, relay protection, and controls.

Waterbury #22. The dam was constructed in 1938 and received significant repairs in 2006. Although we operate the facility, the dam itself is owned by the State of Vermont, and operates under a recently renewed 40-year FERC license that expires in 2056. 2018 is the first year of operations under the new license regime as improvements were completed in June of 2018. The generation output has been reduced and the facility is no longer in the dispatchable market as the site transitions to a run-of-river operation.

Operational License: FERC 40-year license that expires in 2056.

Recent Improvements: To best meet the FERC and 401 requirements while maximizing generation, we replaced the turbine runner with a runner that produces more efficiently at lower flows earlier this year. In 2019, we will complete the FERC-required recreational projects. For the facility to move to true run-of-river, the State must repair gates on the dam. This is likely to occur in the next five to 10 years.

West Danville #1. Run-of-river facility with limited storage capacity located on Joe's Pond in West Danville.

Operational License: Non-FERC jurisdiction.

Recent Improvements: We resurfaced the dam in 1996. In 2011, Hurricane Irene significantly damaged the facility, which we repaired in 2014. In 2014, we upgraded the penstock from the surge tank to the powerhouse; last year, we upgraded the dam control system; this year, we overhauled the unit because of mechanical failures.

Weybridge. Dispatchable facility located on Otter Creek in Weybridge; one of three facilities that comprise the Middlebury Composite.

Operational License: FERC 30-year license No. 2731 that expires in 2031.

Planned Improvements: In 2020, we plan to mechanically refurbish the runner.

Expanded Hydro Fleet Acquired from Enel

We expanded our renewable portfolio in 2016 with the acquisition from Enel of 12 small hydro plants located in Vermont, New Hampshire, and Maine. The plants can be generally described as small, run-of-river power stations that are similar to our existing hydro portfolio. Seven of the plants were incorporated into existing or expanded operating districts: Woodsville, Barnett, and Newbury into the St Johnsbury district; Dewey's Mills, Ottauquechee, Mascoma, and Lower Valley into the Cavendish-White River district, and West Hopkinton, Kellys Falls, Somersworth, Rollingsford, and Salmon Falls into a newly created New Hampshire-Maine district.

During 2018, we transitioned several generating units that were historically represented in the ISO-New England market as “composite” resources to operation as load reducers.⁴³ This change avoided some operational challenges associated with offering output from a composite system into the market and responding quickly to ISO-New England instructions reflecting changing market conditions at five minute intervals. We plan to dispatch the limited storage capability of these units (along with distributed storage and controllable load resources) to maximize energy output during peak load conditions on the VELCO and ISO-New England systems, with the goal of limiting our share of RNS transmission charges and regional capacity market costs. The Lower Lamoille Composite, which includes the Clark Falls, Milton, and Peterson plants, still operates as a composite resource.

Owned Peaking Generation

We own a fleet of six oil-fired generators that operate in a peaking role. These units operate primarily during peak load days (or other times when energy market prices in the ISO-New England market are unusually high); they also are sometimes operated to support the Vermont transmission system and to provide ancillary products (for example, quick-start operating reserves) required for operation of the NEPOOL system. All units' air permits were renewed in 2018. Although these plants do not operate often (typical annual capacity factors for these units are less than one percent), they provide significant value for our customers—primarily through their value in the Forward Capacity Market (FCM) and Forward Reserve Market (FRM). These revenues depend on the ability of the plants to respond quickly and reliably during the occasional periods when they are called upon to operate. Reliable operation is becoming even more important, as the ISO-New England Pay-For-Performance Program penalizes capacity sources that fail to produce during regional shortage events and rewards those that do

⁴³ The Glen and East Pittsford plants made up the former North Rutland composite resource; the Salisbury, Silver Lake, and Weybridge plants made up the former Middlebury composite.

(as explained in Chapter 3: Regional and Environmental Evolution). We have reviewed our operation and maintenance regimes for these units with the goal of maximizing availability. We expect that ongoing activities will include performing monthly test starts—targeting worst-case periods, such as extreme temperatures when possible—and continuing internal inspections of the turbines each spring.

Resource Name	Age (years)	Nameplate MW
Ascutney Gas Turbine	57	12.5
Berlin 1 Gas Turbine	46	46.5
Essex Diesels	12	8.0
Gorge Gas Turbine	53	17.0
Rutland 5 Gas Turbine	55	12.5
Vergennes 5 & 6 Diesels	55	4.0
Total		100.5

Table 5-4. Owned Peaking Generation

Ascutney Gas Turbine. The Ascutney Gas Turbine is a two-stage turbine, internal combustion unit located in Ascutney. The unit operates under an air pollution control permit issued by the VANR’s Air Quality and Climate Division. Significant recent improvements include the replacement of the fuel control system, voltage regulator and auto synchronizer, and unit automation upgrades in 2018. Replacement of the engine section as part of a hot gas path and overhaul project was completed in 2011.

Berlin 1 Gas Turbine. The Berlin Gas Turbine facility is the largest peaking plant in Vermont, and consists of a Pratt & Whitney Twin Pack gas turbine generator and two Pratt & Whitney Simple Cycle FT4 engines. The unit has an approximate capacity of 50 MW at full output in winter, and about 40 MW in summer. Low-sulfur kerosene fuels the engines from two on-site fuel tanks.

In 2008, the Berlin Gas Turbine facility was upgraded; both engines were overhauled and rebuilt, together with a complete rewind of the generator. An additional air-assisted start pack was installed, enabling both engines to start simultaneously. Additional improvements, upgrades and replacements were made in 2012 and 2013. As a result of the upgrades, the plant can more fully participate in the ISO Reserve market, the life expectancy of the plant was extended, and reliability improved.

Essex Diesels. This diesel generation facility consists of four 2 MW Caterpillar diesel reciprocating engines that operate on ultra-low sulfur diesel. In 2007, we upgraded the facility, replacing 60-year-old, 1 MW Electro-Motive Division (EMD) diesel engines and upgrading all associated switchgear and controls.

Gorge Gas Turbine. The Gorge Gas Turbine is a two-stage turbine, internal combustion unit located in Colchester. The unit operates under an air pollution control permit issued by the VANR's Air Quality and Climate Division. The Gorge Gas Turbine underwent a major overhaul in 2014 and is slated for a control system upgrade in 2019.

Rutland 5 Gas Turbine. The Rutland Gas Turbine is a two-stage turbine, internal combustion unit located in Rutland. The unit operates under an air pollution control permit issued by the ANR's Air Quality and Climate Division. Significant improvements include the replacement of the fuel control system in 2006, and refurbishment of the unit's engine components as part of a hot gas path inspection and overhaul project in 2009. We are currently evaluating the costs and benefits of this gas turbine based on recent experience featuring poor reliability and significant unplanned outages.

Vergennes 5 & 6 Diesels. The Vergennes peaking facility consists of two 16-cylinder reciprocating engines, originally installed in 1964, with a total nameplate capacity of 4 MW. The engines are fueled using ultra-low sulfur, blended #2 diesel oil. Both engines have been overhauled in the last decade. In 2013, we installed a DOC catalyst to the emissions control system and, in 2014, upgraded the unit's control systems. In 2018, the generator for Unit 5 failed and was rewound; we are planning to rewind Unit 6 in 2019.

Owned Wind Generation

We own two utility-scale wind plants. The first, Searsburg Wind, is a 6 MW facility located near the Massachusetts border. The second is Kingdom Community Wind (KCW). With a nameplate rating of 64.5 MW, KCW entered commercial operation in 2012, and is located in the town of Lowell in northeastern Vermont.

Kingdom Community Wind

Kingdom Community Wind is a 21-turbine wind generation facility. We partnered with Vermont Electric Cooperative (VEC) to build the project, which began generating electricity at the end of 2012. The wind turbines at Kingdom Community Wind were manufactured by VESTAS, and are rated at just over 3 MW each. We own 100% of the project, and retain 87% (55 MW) of the output for our customers. The remaining output serves VEC customers, via a long-term power sale agreement. The plant is expected to operate at a 33% annual capacity factor, which yields approximately 186,000 MWh of energy annually. Since the Jay synchronous condenser facility was installed and fully operational in spring of 2014, the project has produced at approximately this level, with the exception of some reductions because of a transmission system constraint.



Figure 5-9. Kingdom Community Wind

During operation in winter months, Kingdom Community Wind sometimes experiences accumulation of ice on turbine blades. This tends to occur with the arrival of freezing rain, and can also occur through accumulation of heavy wet snow on leading edges of blades. In such instances, some or all of the turbines may need to be shut down until the ice accumulation can be shed (after a few hours to a few days). In recent years, we have sought to limit the duration of such events by proactively taking the plant offline (so that the blades are not rotating)

when weather at the facility appears conducive to turbine blade leading edge buildup. This method appears to have limited ice buildup (and associated lost generation) in recent years. We plan to continue seeking a technology that is in production (and approved by the turbine manufacturer Vestas) that will assist in ice shedding once ice has accumulated on blades; at this time, no technology is available for installation on Vestas V112 model turbines that are already in operation.

KCW has also been susceptible to lightning strikes that have damaged blades on average of about once per year. During initial years of operation at KCW, the process of repairing lightning damage to the spar of a turbine blade meant craning a blade to the ground, making the carbon repair, and then reinstalling the blade on the turbine. This method of repair has historically been costly, and would require the affected turbine to remain out of service for approximately 30 days depending on the time of year and relative ease of site access. In recent years, we have worked with Vestas to complete the fiberglass and carbon fiber repairs without removing the blade from the tower. Technicians can utilize a man lift, or a blade access platform basket to complete the needed repairs. This method of repairing blades has significantly reduced the cost associated with blade repairs, as well as reducing lost generation associated with the turbine being off line for extended periods of time.

Searsburg Wind

Searsburg is an eleven-turbine facility completed in July 1997, the first utility scale facility installed in the Northeast. After twenty years of production, Searsburg continues to be fully operational, producing energy at an average annual capacity factor between 20 and 25%. In fact, the plant has produced some historical monthly high generation totals within the past two years.

Searsburg remains powered by the same Zond turbines that were installed in 1997. Zond has been out of business as a turbine manufacturer for many years, and turbine parts at

times have been difficult to locate. We have been able to find vendors that were able to remanufacture parts needed to keep turbines operational. We have also been successful in locating some turbine parts (for use as spares) from other plants in the western U.S. that were repowered with newer turbines, and have taken Zond units out of service. The turbine operating system (SCADA) was upgraded in 2016. We proactively have one gearbox rebuilt yearly, to minimize the chance that gearbox failures will require extended outages. Generators are also long lead time items; we store one spare generator locally as a backup, and rebuild failed generators as needed. Parts including controller circuit cards and other electronic components can be difficult to locate.

We expect to continue maintaining and operating Searsburg for the foreseeable future, using the methods specified here and making repairs as needed. We recognize that, in the future, some types of component failure could conceivably make it infeasible (or not cost effective) to return one or more units to service. In the long-term, the Searsburg site could potentially be repowered—by replacement in kind (for example, same or similar number of units, sized equivalent to the current units) or by installing a smaller number of larger turbines. We expect to evaluate these options in the future based on the trend in Searsburg performance and other factors.

It is important to note that the Deerfield Wind project was recently constructed directly adjacent to the Searsburg facility and shares some facilities such as access roads. This provides a more cost-effective opportunity to re-power Searsburg in the future.

Owned Solar Generation

We have embraced solar PV technology, particularly as its cost-competitiveness improved over time. The 2 MW (AC) Stafford Hill solar and battery storage project, constructed on a closed Rutland landfill in 2014, was our initial launch into utility-scale solar and battery storage. In 2016, we commissioned five additional solar projects; in 2018, we added a 1 MW-4 MWh of utility-scale battery storage in Panton. In total, including several smaller solar generation projects installed at GMP-owned properties and partner sites, we own about 25 MW of solar capacity. In addition, we have proposed installing a total of approximately 14 MW of solar PV capacity, along with 6 MW-24 MWh of battery storage capacity, in 2019 as part of the Joint Venture Solar and Storage program.

Here are additional details about components of our solar PV generation fleet.



Figure 5-10. Stafford Hill Solar Facility

Stafford Hill. The Stafford Hill project was an innovative, first-of-its-kind project using solar, two types of battery storage and a common inverter to tie it all together on top of a previously capped landfill. Under normal operating conditions, this project will supply energy to the grid while the battery system continues to smooth, regulate and support the grid throughout the day. We are able to achieve significant capacity-related savings by

maximizing the plant's output (through a combination of solar generation and battery discharge) during the ISO-New England annual peak load, and discharging the battery system during monthly peak loads on the VELCO system. The battery storage system has also achieved revenue as a supplier of Regulation Service in the ISO-New England market. Finally, the project can electrically island the nearby Rutland High School emergency shelter during times of grid emergency utilizing the battery and solar to power the facility. We are presently exploring an upgrade to the lithium-ion batteries at the Stafford Hill site to allow greater participating and therefore additional revenue in the ISO regulation market but will be weighing this against the cost of this upgrade.

Joint Venture Solar. Five utility-scale solar projects were commissioned in 2016: 4.7 MW (AC) in Williston; 2 MW (AC) in Richmond; 4.9 MW (AC) in Hartford, 4.9 MW (AC) in Panton; and 4.9 MW (AC) in Williamstown. All of the projects utilized fixed-tilt racking systems, with the exception of Panton, which was designed for single-axis trackers. Hartford was notable because its re-use of the site of a former gravel extraction operation. Williston included a creative partnership with Global Foundries to provide that customer with a portion of the project's output in return for hosting the site. The estimated lifetime cost of power from the Joint Venture Solar projects was the lowest among Vermont solar PV projects at the time the projects were developed. In 2018, a 1 MW-4 MWh battery system was commissioned on the Panton solar site, which is now providing peak load reduction and frequency regulation services to the grid.

Joint Venture Solar and Storage. We are in the final stages of permitting three additional solar and battery storage projects which, if approved, will be commissioned in 2019. At each project site (Milton, Ferrisburgh, and Essex), there will be between 4.5 MW (AC) and 4.9 MW (AC) of solar generating capacity and 2 MW-8 MWh of battery storage. The batteries will primarily be charged by the solar generation and the batteries will in turn, be used to achieve peak load reductions and frequency regulation services to lower power costs for customers. Like Panton, Ferrisburgh will feature single-axis trackers while Milton and Essex will use fixed-tilt racks because of their topology. Each of these

projects will take advantage of significant cost declines for solar PV and battery projects in recent years, and will enable us to lower the cost to our customers by taking advantage of the federal investment tax credit that is presently available on both the solar and storage components of combined projects. As a result, we expect that the lifetime cost of power to customers from the solar components of these projects will be the lowest of any Vermont solar PV projects developed to date.

Other Owned Solar. We have installed solar PV equipment at a number of our sites as well at sites owned by partners, and also on streetlights. For example, we have installed projects at the site of the Berlin Gas Turbine, at a site on Cleveland Ave (Creek Path Solar) in Rutland, and at a number of our office buildings. We've also installed projects at Rutland Region Medical Center and the College of Saint Joseph's in Rutland.

GMP-owned plants represent a small fraction of the number of projects and total capacity of solar PV development in Vermont. The vast majority of solar development has occurred through the net metering program and the Standard Offer program, along with bilateral PPAs under which we purchase the output of specific projects.

Net-Metered Solar Generation

Vermont's net metering program has existed for almost 20 years, with the primary purpose of enabling customers to offset their electricity usage with their own on-site generation. In Vermont, net metering is administered under PUC Rule 5.100. When we pioneered the use of a six-cent per kWh solar "adder" for net-metered solar projects in 2008, solar PV generation in Vermont was generally not cost-competitive relative to wholesale power alternatives or with retail electricity rates. We implemented this adder to support the development of customer-sponsored local generation, and its significant magnitude reflected that fact at the time. The estimated value of solar PV output to us could (in part because of its coincidence with local and regional peak demands) significantly exceed the retail electric rates that net metering customers could avoid through their generation.

The *Vermont Energy Act of 2011* required (among other things) that GMP and other Vermont utilities offer solar adders that would result in total payment rates for net-metered solar generation at 20 cents per kWh, while guaranteeing the associated incentive for 10 years. The Act also increased the size of generators eligible for net metering to 500 kW, an order of magnitude larger than the early residential scale projects in our territory. This change, combined with the fact that Vermont allows virtual net metering (that is, a net-metered project located remotely from the customer receiving credit for the output) set the stage for much more rapid growth. Act 99 of 2014 greatly increased prior caps on the total volume of net-metered generation projects in a utility's

territory, and allowed solar facilities up to 5 MW (if located on a closed landfill) to be treated as net metered. Act 99 also charged the PUC to create a new framework for net metering, beginning in 2017, and to balance the setting of payment rates to stimulate development with potential shifting of electric system costs to non-participating customers.

Because of a rapid decline in the cost of solar PV project costs (including panels and other components, along with installation) and the expansion of eligibility to projects up to 500 kW, the quantity of net-metered generation capacity in our territory has increased at an extraordinary pace in the past four years—from total operating capacity of about 40 MW in mid-2014 to about 163 MW as of mid-November 2018. This scale of net-metered capacity (relative to electricity demand) places us as an industry leader; it also has implications for the value of additional solar power.

Figure 5-11 illustrates the cumulative volumes of net-metered capacity that have applied for interconnection since 2014 (the green line), while the red line depicts the capacity that has achieved commercial operation or is still under development. The difference between the two lines reflects attrition—that is, capacity from projects that applied for interconnection but ultimately withdrew because of permitting challenges, financial feasibility, or other reasons. As evidenced from Figure 5-11, net metering applications have increased steadily since 2014, with the pace punctuated by a large surge in late 2015 (as a temporary 15% cap in program capacity was approached).

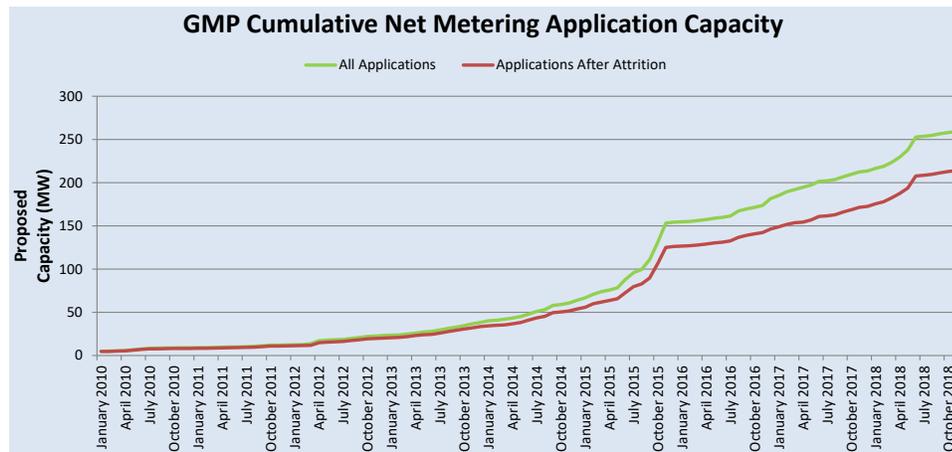


Figure 5-11. Cumulative Net Metering Interconnection Applications to GMP

The applications shown in Figure 5-11 have translated into large increases in operating net-metered generation capacity. The growth has been overwhelmingly in solar PV projects, which presently make up about 96% of the net-metered generation fleet.

5. Our Increasingly Renewable Energy Supply

Current Supply Resources

Figure 5-12 tracks the growth of operating net metering capacity in our territory from 2010 to the present. While the vast majority of net-metered projects are residential scale (up to 15 kW), the most explosive growth of net-metered capacity has been in the large (up to 500 kW) category.

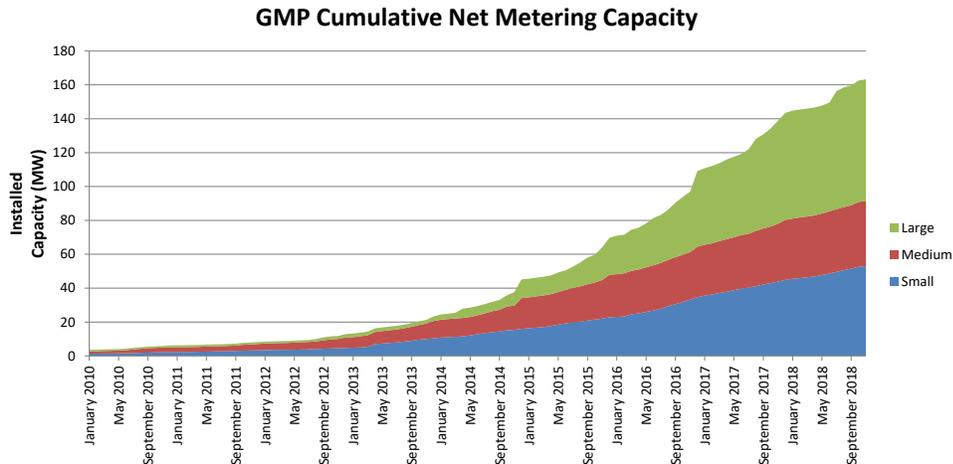


Figure 5-12. Cumulative Net Metering Capacity

Figure 5-13 presents an alternative view of this net metering information, showing the total net-metered generating capacity that achieved commercial operation in each calendar year. Since 2014, the amount of net-metered capacity reaching commercial operation has ranged from a low of over 20 MW in 2014 to a maximum of almost 40 MW in 2016.

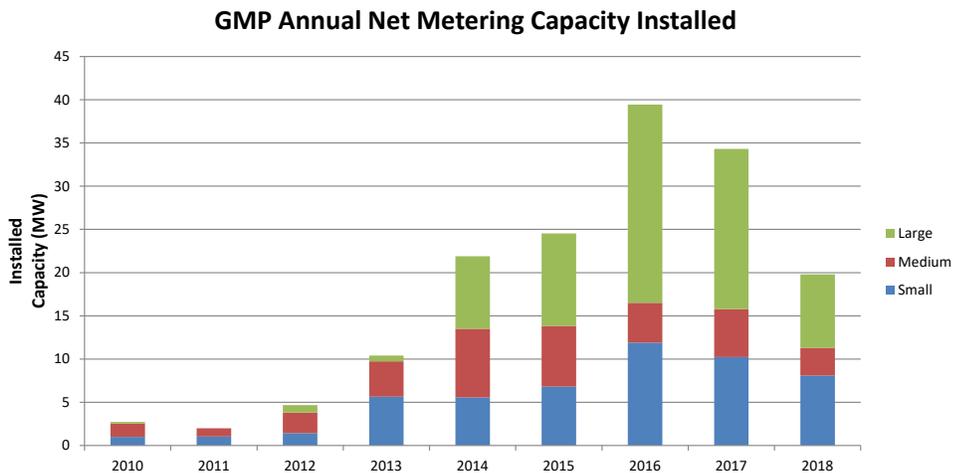


Figure 5-13. Annual Net Metering Installed Capacity

The extraordinary growth of net metering in our territory (relative to electricity demand) has been more rapid than for the industry as a whole, including other leading solar states. Net metering has become by far the largest source of solar PV in our territory, with much greater capacity than solar PV from larger sources (MW-scale PPAs, or utility-

owned project) which can be obtained at substantially lower cost per kWh. This is a particular concern for large-scale (up to 500 kW) projects, which are often located remotely from customer load and don't offer operational advantages relative to lower-cost larger solar sources. During the same period that net metering and other initiatives have been very successful at supporting the development of new solar capacity, the value of additional solar power (above that already in place) has declined significantly. As a result, additional net-metered generation at current payment rates tends to put upward pressure on our net power costs and retail electric rates.

There are two primary reasons for this. First, the success of solar PV deployment in Vermont has lowered peak loads during daytime hours, shifting the remaining peak loads primarily to evening hours when solar power is not generating. While initial installations of solar PV in Vermont were estimated to provide several cents per kWh of value in the form of reduced regional transmission charges and potential deferral of peak-driven transmission and distribution capital projects, it is likely that additional solar PV will provide only minimal benefits of this type.⁴⁴

Second, near-term wholesale market prices for energy, capacity, and regional Class 1 RECs in New England, along with expectations for those prices in the future, have each stabilized or declined over time. For example, "7x24" (round-the-clock) energy for delivery in the next several years (2019 through 2022) is presently available for a fixed price of about 4 cents per kWh; a few years ago, broker indications for similar forward purchases were priced at more than 6 cents per kWh. These market price declines affect the value of additional solar PV power, as well as the value of other potential power resources.

Starting with net-metered generation projects applying for interconnection in 2017, the PUC established that payment rates should be differentiated in two ways. First, net-metered customers who elect to transfer the renewable attributes associated with their projects to the host utility to help meet RES requirements receive a positive REC Adjustor (presently 2 cents per kWh). Net-metered customers who elect to retain the renewable attributes (for example, in anticipation of selling them, or to be able to claim that their home or business is fully powered from the net-metered project) receive a negative REC Adjustor. Second, each project receives a Siting Adjustor, which may be positive, zero, or negative depending on the size of the project and whether the project is located on a "preferred" site. In general, larger projects that are typically able to achieve greater scale economies receive lower Siting Adjustors—and therefore somewhat lower total payment rates for their output.

⁴⁴ The shift in Vermont peaks into evening hours does not mean that peak load reductions that were caused in part by past deployment of solar PV (including net metering) are lost, but it does mean that additional volumes of solar PV will provide much less value per kW to GMP customers than the initial volumes did.

5. Our Increasingly Renewable Energy Supply

Current Supply Resources

As a result of the PUC’s biennial review of the net metering program, payment rates for new net-metered generation were lowered somewhat, effective with applications received starting July 1, 2018. Specifically, the REC Adjustor available to all projects was reduced from 3 cents per kWh to 2 cents per kWh; this Adjustor will be reduced to 1 cent per kWh for projects proposed from July 1, 2019 onward. In addition, the Siting Adder available to large projects (those with the greatest potential scale economies) was lowered by 1 cent per kWh.

Table 5-5 illustrates the current (as of mid-November 2018) status of our net metering queue: active and proposed projects for the small, medium, and large size ranges. The header “NM 1.0” refers to projects that applied to interconnect in 2016 or earlier; “NM 2.0” refers to projects that applied from January 1, 2017 to June 30, 2018; while “NM 2.1” refers to projects that applied July 1, 2018 or later.

Size	Status	Solar NM 1.0		Solar NM 2.0		Solar NM 2.1		Non-Solar NM		NM Totals	
		#	Capacity (MW)	#	Capacity (MW)						
Small	Active	6,379	38.9	1,923	12.5	139	0.9	82	0.5	8,523	52.8
	Proposed	1	0.0	373	3.1	234	1.7	3	0.0	611	4.8
Medium	Active	416	32.2	76	4.7	2	0.0	17	1.6	511	38.5
	Proposed	3	0.3	113	10.9	20	0.7	1	0.1	137	12.0
Large	Active	120	66.0	4	1.8	0	0.0	12	4.0	136	71.8
	Proposed	6	2.9	59	28.6	6	2.5	0	0.0	71	34.0
Total Active		6,915	137.1	2,003	19.0	141	0.9	111	6.1	9,170	163.1
Total Proposed		10	3.2	545	42.6	260	4.9	4	0.1	819	50.8
Combined Total		6,925	140.3	2,548	62.6	401	5.8	115	6.2	9,989	213.9

Table 5-5. Net Metering Resources: November 16, 2018

There is about 163 MW of active net-metered generating capacity on our distribution system, and a queue of about another 51 MW of proposed projects that have applied for interconnection.

A few other observations about the net metering fleet:

- About 96% (all but 6 MW) of operational net metering capacity is from solar PV projects.
- Almost 93% of net metering systems (over 8,500) are in the small category; they make up only about 53 MW (or about 32%) of installed capacity.
- Large systems make up 72 MW (or about 45%) of operating capacity, and about two-thirds of proposed projects.

- The bulk of project capacity that has been proposed (but not yet completed) is from “Net Metering 2.0” projects that applied for interconnection before July 1, 2018, particularly during a surge of applications submitted between February and June 2018. The pace of new applications since July 2018 has been slower, particularly for large projects.

Jointly Owned Generation

We have joint ownerships in four generation facilities and one transmission facility. The generation facilities include one nuclear, one wood, and two fossil-fuel projects, representing baseload and peaking capacity.

Resource Name	Age (years)	GMP Share Nameplate MW	2017 MWh
McNeil Station	34	15.5	83,382
Millstone #3	32	21.3	168,147
Stony Brook 1A, 1B, 1C	37	31	8,472
Wyman #4	40	17.7	2,653
HVDC Phase 2 Transmission	28	112	n/a
Total		270.5	266,461

Table 5-6. Jointly Owned Generation

McNeil Station. McNeil Station is a 50 MW wood-fired generation facility located in Burlington; the plant began operation in 1984. Our ownership share is 31% (about 15.5 MW); we therefore receive that fraction of output and pay for that share of the plant’s operating costs. McNeil can also operate using natural gas (either alone or in combination with woodchips), although this only rarely occurs in actual practice. Burlington Electric Department (BED) owns 50% of the facility and the Vermont Public Power Supply Authority owns the remaining 19%. BED operates the facility on behalf of the joint owners.

In 2008, a selective catalytic reduction system was installed on the plant to reduce its nitrogen oxides (NOx) emissions. This emission reduction enabled the plant’s output to qualify as eligible for compliance with Connecticut Class 1 RPS. As a result, in recent years, we (often in collaboration with other McNeil joint owners) have sold most or all of our share of McNeil RECs to load-serving entities in Connecticut for RPS compliance, with the associated revenues used to reduce our net power supply costs and retail electric rates. The production of valuable RECs (in addition to energy) has supported the operation of McNeil at well over a 50% capacity factor. Although the market value of McNeil’s output is expected to decline significantly in the near-term because of declines in market prices for energy (in non-winter months) and Connecticut

Class 1 RECs, we assume that McNeil will continue to operate during this IRP planning horizon.

Millstone #3. Millstone Unit #3 is a 1,235 MW pressurized-water base-load nuclear reactor situated in Waterford, Connecticut, on Long Island Sound. It is part of the three-unit Millstone Station. Millstone #1 is being decommissioned, while Millstone #2 is actively generating. Millstone #3 began commercial operations in 1986; we own a 1.7303% (21.5 MW) share of the unit. Dominion Nuclear Connecticut owns 93.470% of the unit with the Massachusetts Municipal Wholesale Electric Company (MMWEC) owning the remaining 4.799%. Dominion Nuclear Connecticut operates the facility on behalf of its joint owners.

The Millstone #3 operating license from the NRC runs through November of 2045. The future decommissioning of Millstone #3 is supported by dedicated Decommissioning Trust Funds for each joint owner.

Stony Brook 1A, 1B, 1C. The Stony Brook Station, located near Springfield, Massachusetts, hosts a combined-cycle gas- and oil-fired generation facility with both peaking and intermediate units. The intermediate units (1A, 1B, and 1C) have a combined capacity of 353 MW and typically operate as peaking generation with an annual capacity factor of under five percent. The primary fuel is natural gas, although the plant has operated regularly on oil (and provided value to our customers) for significant periods during cold snaps in recent winters, when regional scarcity of natural gas supply made operation on gas uneconomic. This dual-fuel capability provides important protection against the physical unavailability and financial costs associated with potential interruptions of natural gas supply. The combined-cycle plant can be started relatively quickly in response to regional market contingencies, and can be operated over a wide range of output levels. Stony Brook began commercial operations in 1981. We own an 8.8029% (31 MW) share of the combined intermediate units, along with a smaller share of output through a long-term PPA. MMWEC operates the facility on behalf of its joint owners, which are mostly Massachusetts municipal utilities.

Wyman #4. The Wyman Station facilities, located on Cousins Island near Yarmouth, Maine, comprise four generating units. Unit 4, the largest at 606 MW, is a steam unit that burns residual oil as the primary fuel, and functions as a peaking generator in the ISO-New England dispatch; it can be dispatched over a wide range of output levels. Unit 4 began commercial operations in 1978 and was originally intended to function as an intermediate dispatch unit. Wyman #4 earns FCM and other ancillary product revenue from ISO-New England. We own a 2.9207% (17.7 MW) share of Wyman #4; NextEra owns 84.346% of the plant and operates the facility on our behalf and the unit's other joint owners. The plant has been economically dispatched at low annual capacity

factors in recent years, but it tends to be dispatched more heavily (and provide savings to our customers) during winter cold snaps, when regional natural gas prices and energy market prices are high. As a steam unit that requires many hours to start, Wyman #4 is not expected to be able to respond to shortage events that are triggered by unexpected regional contingencies (for example, trips of major generating units or transmission elements) that arise quickly.

HVDC Phase 2 Transmission. The Phase 2 transmission and converter terminal facilities interconnect the Hydro-Québec system to the ISO-New England system with a nominal transfer capability of 2,000 MW. We have both an equity ownership share and a leased share of the facility providing use rights to approximately 8% the facility's available transmission capacity (approximately 112 MW of firm capacity at typical availability). ISO-New England recognizes the contribution of this interconnection to regional resource adequacy, and presently provides us with roughly 80 MW per month of FCM Hydro-Québec Interconnection Capability Credits (HQICC). We currently resell the energy-use rights of the facility short-term to other entities wishing to import energy across the facility, with the revenue used to reduce our net power costs. We expect to renew the current facility-use arrangement when the lease expires in 2020.

Highgate Converter. The Highgate Converter is a back-to-back AC-DC-AC facility located near Highgate Springs, with transmission capability as high as 225 MW connecting with Hydro-Québec to the north and the VELCO system to the south. It began commercial operations in 1985; its annual capacity factor for energy deliveries has typically been about 75%. The facility has primarily been used to import Hydro-Québec Vermont Joint Owner (HQ-VJO) power, but exports are also possible. We sold our 82.29% (185 MW) share of the facility to VELCO in 2017, with the goal of lowering net cost to our customers. VELCO is now the primary owner of Highgate and operates the facility on behalf of the joint owners.

Long-Term Power Purchase Agreements (PPAs)

The majority of our energy supply comes from long-term PPAs with individual suppliers. Until the Vermont Yankee (VY) contract expired, the VY and HQ-VJO PPAs supplied the vast majority of the energy requirements of the legacy companies. We have transitioned away from a few large PPAs toward smaller and more diverse resources, including new nuclear and hydro-based PPAs, an 82 MW wind PPA, and other purchased and owned resources. Through the IRP planning period, we receive a significant portion of our energy from a few large, long-term PPAs (HQ-US and NextEra), but significantly less than earlier in the decade.

5. Our Increasingly Renewable Energy Supply

Current Supply Resources

Table 5-7 depicts current contracts and illustrative 2017 energy volumes.

Generator Name	Contract Period	Contract MW	2017 MWh
Hydro Québec-United States ¹	2012-2038	178	1,041,727
Moretown Landfill	2009-2023	3	11,798
Granite Reliable Wind	2012-2032	82	170,994
Small Renewable PPAs—Solar	Various	43	46,808
Small Renewable PPAs—Other	Various	36	93,159
NextEra Seabrook (unit output) ²	Through 2034	60	476,658
NextEra Seabrook (capacity only) ³	Through 2034	175	none
Stony Brook 1a, b, and c	1981-Life of Unit	15	3,807
Deerfield Wind ⁴	2017-2042	30	-
Total		622	1,844,951

1 The HQ-US contract delivers firm energy without capacity.

2 We purchase energy and capacity from NextEra Seabrook under two long-term PPAs; for simplicity, we have presented their energy and capacity components separately in this table.

3 Our purchase of plant-contingent energy, capacity, and generation attributes from NextEra Seabrook is presently 60 MW; it will decline to 55 MW in 2021 and to 50 MW in 2029.

4 Began commercial operation on December 27, 2017.

Table 5-7. Long-Term Power Purchase Agreements

Hydro-Québec-United States. In April 2011, GMP and a group of other Vermont distribution utilities received approval from the PSB for a 26-year PPA with Hydro-Québec-United States (HQ-US) starting in November 2012. Our current share of the purchase increased to about 170 MW at the end of 2016 as the HQ-VJO contract expires. The HQ-US PPA will provide annual energy volumes of approximately 1,000,000 MWh per year (representing about 22% of our current annual energy requirements) during much of the delivery term, in a flat schedule during the peak 16 hours of every day. These deliveries are financially firm and not contingent on the operation of particular generating units or transmission facilities. In addition to the energy delivered, the PPA includes all environmental attributes of the power, at least 90% of which will be based on hydroelectric resources, helping us maintain our low-emission energy profile at a relatively stable price that reflects a blend of general inflation and regional energy market prices. No capacity is included in this purchase.



Figure 5-14. Granite Reliable Wind Facility

Granite Reliable Wind. We purchase about 82% of the output from this 99 MW wind plant located in northern New Hampshire under a 20-year contract. This is projected to supply about 5% of our annual energy requirements at a fixed schedule of contract prices. The output of the project includes plant-contingent energy, capacity, and RECs; the size of our purchase declines to about 55 MW in 2027.

Moretown Landfill Gas. In December 2008, we began receiving energy from Moretown Landfill Gas through a 15-year PPA. We receive 100% of

the plant output, which includes energy, capacity, and RECs. This plant operates in a baseload mode; its output was originally about 3 MW. Declining methane production at the landfill has (as anticipated) gradually reduced the typical available output to roughly 1.5 MW.



Figure 5-15. Williston Solar Facility

Small Renewable PPAs. To help facilitate development of local small renewable projects across a range of technologies, we have entered into plant-contingent PPAs for the output from a number of these facilities. About 43 MW of these are solar projects in Vermont, including Rutland, Williston, Panton, Strafford, Williamstown, and Ryegate. The remainder are long-term PPAs for the output of four hydroelectric plants totaling approximately 36 MW (the largest of which is the Sheldon Springs plant at over 25 MW). These purchases represent a small portion of our total power and

REC needs today, although such bilateral purchases from local renewables could be increased over time to help meet our RES Tier II requirements.

Stony Brook 1a, b, and c. As described earlier, we own a small interest in these units. In addition to the ownership allocation, there is a PPA for 4.4% of the output from the facility that runs for the life of the units at a price that follows the cost of operating the facility.

NextEra Seabrook. We purchase output from the Seabrook nuclear facility under two long-term PPAs. The first PPA provides 60 MW of plant-contingent energy, capacity,

and generation attributes; at an illustrative 90% annual capacity factor, this would represent about 473,000 MWh or roughly 11% of our annual energy requirements. Over time, deliveries of these products under the contract are scheduled to decline by 10 MW (about 80,000 MWh per year) starting June 2021 and by another 10 MW starting in June 2029, with the PPA ending in 2034. We also purchased an additional 25 MW of capacity (without associated energy or attributes, and constant over time) under this long-term purchase.

The second PPA provides an additional 150 MW of plant-contingent capacity on a long-term basis, along with 5 MW of additional plant-contingent energy and attributes starting in June 2021, increasing to 10 MW in June 2029 before the PPA ends in 2034.

Overall, the purchase provides low-emission baseload energy and capacity at relatively stable prices, with increases driven primarily by an index of general inflation. Based on the two transactions together, our purchase of plant-contingent energy and attributes is presently 60 MW, declining to 55 MW, and ultimately to 50 MW. The total purchase of capacity declines over time from 235 MW to 230 MW and ultimately to 225 MW.

Although this PPA is one of our largest single sources, the total long-term purchase commitment from NextEra Seabrook is only a small fraction of our former reliance on the Vermont Yankee plant. If the plant were to retire early, there would be a notable adverse impact on the emission profile of our portfolio. The impact on our net power costs would depend on prevailing market prices at the time, relative to the PPA prices for energy and capacity.

Deerfield Wind. We purchase 100% of the output from a 30 MW wind plant located in the towns of Searsburg and Readsboro, under a 25-year contract that also includes an option to purchase the plant for a fixed price after ten years of operation. The plant reached commercial operation and began delivering plant-contingent energy, capacity, and RECs in December 2017. This is projected to supply about 2% of our annual energy requirements at a fixed price.

Long-Term Vermont Policy Resources

NYPA. We receive approximately 0.5 MW of NYPA power, most of which comes from the Niagara Power Plant on the U.S.-Canada border. Although the current NYPA contract expires in 2025, it is projected to remain available through the IRP planning period. Delivery of NYPA energy can be shaped to correspond with the higher load periods of the day, and is expected to amount to about 6,000 MWh per year.

Ryegate. Ryegate is a 21 MW woodchip-fired generator. The plant presently operates under a 10-year contract between Ryegate Associates and VEPPi, mandated by

Vermont's Baseload Renewable Energy Standard. The expected annual plant output is roughly 172,000 MWh; our portion is approximately 82%, or 141,000 MWh per year. The PPA has an estimated levelized price of roughly 10 cents per kWh, with a portion of fuel price risk passed through the PPA price. This price is significantly higher than our current base case outlook for the value of the plant output (energy, capacity, and RECs) that we receive; the PPA expires in late 2022. The portfolio analysis (in Chapter 8: Portfolio Evaluation) assumes that our purchase obligation from Ryegate will expire at that time. The volume of output from this plant is significant enough that if the Ryegate PPA were extended or replaced at pricing similar to the current PPA, the resulting increase in our net power costs starting in 2023 would likely put upward pressure of at least one percent on average electric rates for our customers.

Standard Offer. Under the Standard Offer program, we purchase our load ratio share (presently about 82%)⁴⁵ of output from up to 127.5 MW of participating renewable projects, which must each be sized 2.2 MW or smaller. The PUC appointed VEPPi as the facilitator to administer these resources, which presently include more than 56 solar, hydro, biomass, and methane generators with an aggregate capacity of about 65 MW.⁴⁶ Standard Offer resources generally carry a fixed, levelized price for a term of 20 or 25 years. We estimate these resources will supply about 109,000 MWh to our portfolio in FY 2019 and project that this amount will grow to about 170,000 MWh per year when the program is fully subscribed.

The actual volumes and cost of new Standard Offer power depends on the specific mix of renewable technologies that supply the program, and the actual capacity factors of those plants. The PSB implements the SPEED program as described in Rule 4.300, with the goal to “achieve the goals of 30 V.S.A. §8001 related to the promotion of renewable energy and long-term stably priced contracts for such energy that are anticipated to be below the market price.”⁴⁷ In actual practice, the average price of Standard Offer PPAs has turned out to be far above market, owing primarily to very high PPA prices from projects in the early years of the program, along with declining wholesale market price expectations over time. After a transition to procurement via annual RFPs in 2013, the pace of project completion slowed significantly, as some projects receiving Standard Offer PPAs struggled with a range of challenges (for example, difficulties or delays in obtaining required permits, or delivering on the prices they had offered). The pace of project completion has picked up significantly in the past year; VEPPi anticipates that several more projects will be completed in 2019.

⁴⁵ Program exemptions granted to several Vermont municipal utilities have increased our share of Standard Offer power by several percent in recent years, increasing our net power costs by an estimated \$1 million or more per year.

⁴⁶ For more information, please refer to www.vermontspeed.com.

⁴⁷ Vermont Public Service Board, 4.300 Sustainably Priced Energy Enterprise Development Program, 4.301 Purpose.

VEPPI and PURPA Contracts. We purchase approximately 77% of the output from Vermont’s legacy Qualified Facilities under the federal Public Utility Regulatory Policies Act (PURPA). The PSB appointed VEPPI as the agent to administer these resources, which were contracted in the 1980s and 1990s. A share of the output of these Qualified Facilities is assigned to our power supply portfolio under PUC Rule 4.100, which states that “The purpose of this rule is to encourage development of electricity through use of biomass, other renewable resources, waste and cogeneration, while giving due consideration to the duties and responsibilities of utilities. The rule implements the provisions of 30 V.S.A. Section 209(a)(8) and 16 U.S.C. Section 824a-3.”⁴⁸ Most of these legacy PPAs have expired in the past decade; the remaining fleet includes four hydroelectric generating stations, with two contracts ending by January 31, 2019 and the final two expiring in 2020.

Short-Term Energy PPAs

We source a portion of our energy requirements each year through fixed-price energy purchases from the New England wholesale energy market. These purchases avoid us being substantially exposed to spot market energy purchases at volatile prices, thereby stabilizing our near-term power supply costs and retail rates. We have approached these purchases with the goal of staggering the effective dates and costs to mitigate risk and lower overall cost exposure for customers. For that reason, we have and expect to continue to approach these purchases on layered basis with terms up to five years; this limits the occurrence of large “step” changes in costs when new purchases are implemented or existing purchases expire. Limiting the purchase term to five years or less ensures that the company’s power supply costs maintain some significant linkage to the New England wholesale energy market, and limits the degree to which our power costs can become disconnected from those of utilities in neighboring states that buy a greater portion of their needs in the short-term markets.

Generally, we make these purchases for firm energy (as opposed to unit contingent) from creditworthy sellers, and settle them at the ISO-New England internal hub. We seek to shape the volume of our energy purchases on a monthly basis (and between peak and off-peak hours), to match the shape of our forecasted net open position.⁴⁹ Unless the contracts also include generation attributes from particular sources, they are considered for purposes of describing the fuel mix and air emission profile of our power supply to carry an emissions profile of the New England “system residual” mix.

⁴⁸ Vermont Public Service Board, 4.100 Small Power Production and Cogeneration, 4.101 Purpose.

⁴⁹ As discussed in Chapter 9, our energy needs (that is, load requirements less committed generation sources) tend to be larger in winter and during off-peak hours. We tend to need less energy during spring months and in daytime hours when solar generation is high; sometimes we are a net seller of energy during those hours.

Currently contracted short-term purchases total approximately 1 million MWh for each of FY2019 and FY2020, 700,000 MWh for FY2021 to 2023, and about 400,000 MWh for FY2024 and 2025. Table 5-8 shows total purchases by counterparty including volumes and total costs; the average price of these committed forward purchases over the next five years is about \$47 per MWh. The total costs reflect a number of factors, including the forward energy market outlook at the time that each purchase was contracted, and the period(s) and monthly volumes for each purchase. By design the average price we pay for these forward-market purchases collectively in any given year is therefore not an indication of the current market value of energy in that single period, but rather reflects a weighted average value of multiple contracts that cover multiple delivery periods, negotiated at different points in time, and featuring different market conditions.

Counterparty	Contract Period	Description	MWh	Cost
Macquarie	FY2019	Winter months 7x24	99,405	\$4,612,392
Shell	FY2019-21	Baseload 7x24	512,250	\$20,657,415
BP	FY2019-FY2024	Seasonally shaped 7x24 block	1,973,100	\$100,947,174
Citigroup	FY2019-21	Peak seasons in FY19, baseload remainder	365,425	\$18,196,614
NextEra	FY2019-FY2025	Seasonally shaped 7x24	2,068,430	\$93,804,649
Total			5,018,610	\$238,218,244

Table 5-8. Short-Term Purchased Energy Summary by Counterparty

Short-Term Renewable Attribute Purchases (RECs)

Vermont's RES, which took effect in 2017, requires utilities to meet specific fractions of their retail sales volume with renewable energy. Compliance is demonstrated based on the retirement of RECs in the NEPOOL GIS; the RECs can be obtained from utility-owned generating plants, bundled PPAs (under which the power output and associated RECs from a generating facility are sold together), or unbundled (REC-only) purchases. Utilities also submit annual compliance filings to the PUC that show how the annual RES requirements have been achieved (and address Vermont-specific features like banking of RES compliance across years).

While there are a significant number of supply resources within our supply portfolio that meet the eligibility requirements for RES Tier I and Tier II, we also buy a portion of the required renewable energy through unbundled REC purchases. For example, to help meet the larger Tier I requirements, we have entered into a multi-year transaction with Hydro-Québec that convey generation attributes from hydroelectric sources imported

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into New England over the Phase 2 transmission facility.⁵⁰ Under this transaction which began in 2018, we purchase between 1.5 million to 1.7 million RECs per year, which are delivered quarterly into the NEPOOL GIS tracking system. The purchase continues until late in 2020. We anticipate banking some of these RECs (in excess of its annual Tier I requirements) to meet requirements in subsequent years. We have also purchased smaller volumes of RECs from other New England generators.

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The available supply resources include multiple types of renewable power sources, which vary in terms of their scale, location, relative cost, output profiles, and other features. Some of these sources are options that we could potentially explore and implement directly, while others are policy resources whose volumes and timing are not under our control. We are also able to purchase from (and sell to) the ISO-New England wholesale power market, which can play an important role in enabling us to manage the expected cost and potential volatility in net power costs. We also anticipate a significant role for flexible energy storage—which has the potential to “stack” several forms of value and reduce expected costs and potential volatility. While our power supply strategy and the Vermont RES focus primarily on increasing renewable supply and limiting greenhouse gas emissions in a cost-effective way, local oil-fired peaking capacity (which operates infrequently) can complement this transition by helping to meet our share of regional capacity requirements and by supporting the Vermont transmission and distribution grid. That being said, we envision a time in the not too distant future where we can actually retire our traditional oil-fired peaking generation and replace with a combination of energy storage, flexible demand and bilateral contracts with a focus on not just reducing carbon from our energy supply but our capacity supply as well.

Renewable Generation

Our portfolio includes a variety of renewable resources including wind, solar, biomass, bio-digesters, landfill gas, and both small and large hydroelectric resources.

Net Metering

As previously discussed, the pace of growth of net metering in our territory in recent years has been extraordinary. The future growth of net-metered generation will affect our ability to make other resource choices (such as small-scale solar PPAs). The precise

⁵⁰ As part of the same transaction, we are leasing the use of its Phase 2 transmission rights to Hydro-Québec through late 2020.

pace will depend on a range of factors, including the pace at which solar capital costs continue to decline; the trend of customer interest in net metering; the relative availability of “preferred” sites for larger projects; and future changes in net metering payment rates or other program features. As a result, the volume of future net metering growth represents a significant planning uncertainty for us.

As shown in Figure 5-11, Figure 5-12, and Figure 5-13, annual installations of new net metering capacity in our territory since 2014 have ranged from roughly 20 MW per year to almost 40 MW per year. For this IRP’s portfolio evaluation, we assume as a base case that net metering capacity in our territory will continue to grow at a pace of about 20 MW per year. This pace of net metering growth, combined with other committed sources, would be sufficient to meet essentially all of our estimated RES Tier II requirements over the next decade. Our portfolio evaluation (in Chapter 8: Portfolio Evaluation) also tests the implications of sustained net-metered growth rates as high as 30 MW a year and as low as 10 MW a year.

Wind Power

On-shore wind has represented one of the most cost-competitive sources of new utility-scale renewable power in New England, but it is not clear that additional long-term commitments to onshore wind will be a good fit for our portfolio, at least in the near future. Our primary needs for RES compliance appear to be in the areas of new Tier II (distributed) renewables in Vermont, and lower-cost existing renewables (from Vermont or the region) to meet Tier I requirements. In addition, our power portfolio presently includes a total of 173 MW of wind capacity, from four plants located in Vermont and New Hampshire; on an “average year” basis their production is sufficient to meet an estimated ten percent of our current annual energy requirements. This volume of intermittent wind power also carries a degree of variability in output (over time frames from an hour to a year). In addition, proposed wind plants in Vermont are often sited on mountains where a combination of difficult terrain and/or distant transmission access can increase project capital costs, and we recognize that proposed wind plants have encountered significant resistance in the permitting process.

Recently proposed pricing for off-shore wind projects in New England suggests that this resource could (if the indicated pricing gains are realized, and particularly if further declines materialize over time because of industry experience and scale) potentially become an attractive option for us in the future. The attractive features of offshore wind include relatively high capacity factors (with output weighted toward high-value winter months); the potential for relatively high capacity ratings; and diversity of output relative to our significant existing fleet of onshore wind resources. Because our renewable power needs are small in comparison to potential offshore wind projects, the most likely way

for us to participate would be to seek a long-term PPA as part of a much larger solicitation conducted by a neighboring state or aggregation of states or utilities. As part of the portfolio evaluation (see Chapter 8: Portfolio Evaluation), we address the implications of adding offshore wind in the late 2020s, at assumed pricing (for example, roughly \$75 per MWh, escalating over time) that is consistent with reported pricing offered to Massachusetts in its 2018 solicitation.

Standard Offer

As previously discussed, the Standard Offer program supports the development of new renewable sources sized up to 2.2 MW. In recent years the price competitive block has been filled primarily with solar PV projects, although technology diversity provisions have supported more limited volumes of other types of projects. Our portfolio analysis assumes that the program will continue until the total capacity of operating Standard Offer projects reaches the statutory goal of 127.5 MW in 2024. We do not assume that the program will be renewed after that time, as a central procurement program no longer appears to be necessary in light of the extraordinary growth of renewable power in Vermont. Should the Standard Offer program be discontinued prior to reaching the statutory goal, we believe that the RES framework nevertheless establishes clear expectations that distributed renewable generation should continue over time, and we expect that GMP and other Vermont utilities will be able to effectively solicit additional supplies at competitive prices as needed.

Solar Power

As previously discussed, in recent years net metering has been the primary source of distributed renewables, while some GMP-sponsored projects (up to 5 MW in size) and PPAs have been completed at significantly lower effective prices. The amount of additional distributed renewables that we will need to meet our RES Tier II requirements will depend on the pace of growth for net-metered generation and Standard Offer renewable generation. To the extent that additional distributed renewables are needed, we expect to solicit PPA proposals from qualified generation firms, and to compare those options to additional GMP-owned generation. For the purpose of portfolio evaluation in this IRP, we assume that the primary Tier II resource that it would call upon will be solar PV on the scale of 1 MW to 5 MW, priced in the near-term at about \$85 per MWh levelized. The price of additional solar PV is expected to continue its long-term decline, although the solar ITC will begin to decline in 2020, and will step down to 10% in 2022, which may temporarily interrupt this trend.

Several larger scale solar PV project proposals (up to 20 MW or more) have also been proposed in Vermont, primarily for the purpose of selling their output under long-term

contract to neighboring states. We have not yet purchased output from any of these larger projects, primarily because their size makes them ineligible for RES Tier II and there appear to be other renewable options (primarily existing sources) available at lower cost to meet our Tier I needs. Larger scale solar PV could potentially be an option in the future, however, considering that larger projects may be able to achieve greater scale economies (and lower effective cost per kWh) than smaller projects; solar PV costs are anticipated to decline further over time; and solar PV in some locations could potentially (in combination with energy storage) be used to support local grid resiliency. On the other hand, larger proposed projects warrant careful review with respect to their potential impact on the VELCO bulk transmission system and our subtransmission system.

Hydroelectricity

Hydroelectric resources continue to represent the largest portion of renewable power in our resource mix, and are projected to meet about one-third of our total energy requirements over the next 20 years. The largest single source is the HQ-US contract, which provides firm deliveries in accordance with a fixed schedule. Because hydroelectricity is a resource that can play multiple roles within the portfolio (renewable, zero-air emissions, stable price, stronger winter supply), we will continue to explore adding cost-effective hydroelectric resources to the portfolio as those opportunities arise. In particular, we will continue to seek additional opportunities to increase output from our existing hydro plants and to develop new projects, although we expect that the scale of new projects that are feasible and cost-competitive will be limited. We also expect to explore acquisitions of existing hydroelectric power, through PPAs and/or purchases of specific plants. Our analysis (in Chapter 8: Portfolio Evaluation) tests the potential implications of acquiring additional hydroelectric power on a long-term basis through plant-contingent sources (that is, long-term PPA, or acquiring ownership in existing hydroelectric plants) or a firm PPA basis (as Massachusetts is pursuing through the proposed NECEC project in Maine). Although very limited, we will also look to develop new hydro in Vermont should the opportunity present itself in a way that can be done cost effectively and in conjunction with the community it is located in. This would provide the opportunity for a Tier II resource aside from solar, with better supply in the winter months and higher capacity factor for production.

Biomass Power

As a joint-owner of McNeil and the majority off-taker of Ryegate, we presently receive about 5% of our energy requirements from woody biomass. Biomass plants have some advantages (not intermittent, able to produce power in a baseload duty cycle) relative to

other new renewables, and they also have the potential to support significant local economic activity. Newly constructed biomass plants appear to be much less cost-competitive than both wind and solar, however, and existing biomass plants in the region are under financial pressure from moderating market prices for energy and regional Class 1 RECs. Low market prices are particularly challenging for biomass plants because in addition to a significant capital cost (\$/kW), they also face a significant fuel expense (\$/MWh) and non-fuel operating costs, in fact, two biomass plants in New Hampshire (the Pinetree Power plants in Bethlehem and Tamworth) have recently announced plans to operate under reserve shut-down status with the option of restarting if economic conditions improve or if they are called by ISO-New England. In contrast to wind and (particularly) solar, we are not aware of any technological changes that are expected to lower the cost of biomass energy in a major way in the near future. We have therefore not modeled utility scale biomass as a new resource for evaluation in this IRP, and have not continued Ryegate in the modeling past our current contract obligation.

Bio-Digesters

Methane-producing farm digester systems have been a part of our mix for a number of years, and continue to be added under the Cow Power program. As previously mentioned, these facilities are owned by the farmers, with the revenue from the electricity and renewable credits flowing back to them. As we explore the next generation of these facilities, we believe that a GMP-owned model that incorporates both farm manure as well as pre- and post-consumer food waste could provide substantial benefit for Vermonters. The current technology for digesters, their generation sets, pumps, and other equipment require substantial capital investment that provides a real hurdle to the economics of this type of project when they are evaluated solely on the basis of their power supply benefits. One possible strategy for supporting bio-digester projects is to value other benefits such as phosphorous and nitrogen capture that can help to decrease farm runoff into streams, rivers, and Lake Champlain, and to determine if there is way to monetize these benefits to help rationalize the economics of bio-digesters. Given the challenges, we conservatively have not modeled increased bio-digester production in this planning period.

The Vermont Legislature has recently taken a step forward with the passing of Act 148, which requires a phased-in approach to ultimately keep all food waste out of landfills. This creates an opportunity to capture this abundant waste stream and turn it into energy, as well as heat and other products, such as compost. This can further be combined with wastewater treatment facilities to produce additional methane, which can also be used to generate clean electricity.

Geothermal Power

We are not aware of any commercial-quality sources of geothermal energy for electricity production at present, so geothermal resources are not specifically considered in the resource plan.

Battery Storage

Battery storage is a rapidly emerging tool for utilities in New England that has been driven by significant technological improvements and a rapidly declining cost curve in the past decade. In addition, as peak-driven charges (based on monthly or annual peaks) have grown significantly in the past decade, there has been an increased focus on minimizing peaks that are used to allocate transmission (Regional Network Service or RNS) and capacity charges.⁵¹ A number of tools such as demand response (programs through which customers reduce consumption during key peak conditions) and devices (such as our car chargers and water heater controls) that enable responsive load have begun to feature prominently in utilities' strategies for managing peak loads. Battery storage, with its rapid response and ability to accurately discharge, is a new tool that we have begun to use for peak management. This includes the small battery storage devices for home use (for example, Tesla Powerwall batteries) and larger MW-scale devices such as the batteries deployed at our Stafford Hill and Panton PV solar sites.

When evaluating battery storage as a resource, we sum it up with one word: flexible. Battery storage has the amazing ability to act as multiple types of resources, all packaged into one system. These systems can act as loads, generation, a power quality management tool, and a system resiliency tool to name a few. While not every one of these values is easily monetized, they can all play a very important role when it comes to operating a highly distributed and growingly more intermittent energy delivery system. As you have read throughout this IRP, we continue to shift to an energy delivery system that utilizes more and more distributed generation and will require more distributed, managed, energy resources like controllable loads. Battery storage is not purely a peak-shaving resource. At present, cost-effective deployment generally relies on combining or “stacking” several types of benefits, but we will discuss battery storage among peaking resource options because peak management presently provides the majority of estimated power and transmission benefits. Our current use case for battery storage (whether located at customer premises or on the distribution grid) deploys the storage “behind the meter” as load reducers to maximize the benefits that ultimately flow to our customers. The batteries are primarily focused on peak shaving, whereby batteries are discharged for

⁵¹ For example, for each MW decrease in loads during monthly Vermont system peaks, GMP is able to reduce its RNS transmission charges by approximately \$10,000. Reducing one MW of load during the regional peak load hour that is used for allocating Forward Capacity Market requirements can reduce our power costs by about \$100,000.

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periods of up to four hours when we forecast the potential for monthly or annual peak loads to occur. By discharging these batteries, we are able to effectively decrease load requirements from the ISO-New England market during these periods by the total output of all of the batteries connected to our system, which is currently several MW.

In addition to peak shaving, we are currently using our utility scale batteries (those over 1 MW), which as of the time of this IRP filing is our Stafford Hill solar/storage facility and our Panton storage facility, to participate in the ISO-New England Frequency Regulation Market, where the battery receives instructions from ISO-New England every four seconds and reacts almost instantaneously to increase or decrease its consumption or discharge rate to help balance the regional electric system in response to fluctuations in loads and generator output. Historically, natural gas-fired units that were generating at less than full output levels have been used to meet frequency regulation needs, but ISO-New England indicates that battery storage devices are able to react more quickly and accurately than these generators. Our expectation is that battery storage could grow to provide the majority of frequency regulation in New England within the next several years. As more storage devices are offered into the market, our expectation is that the prices paid for participation will probably decline substantially by the early 2020s and we have modeled this assumption into our battery financial analyses. If it turns out that the regulation market remains high, or increases because of the higher penetration of intermittent renewables in the region, the increased value will flow directly to customers.

An additional revenue stream for storage devices is energy arbitrage, whereby batteries are charged during hours with low or negative LMPs and then discharged during hours with higher LMPs. Some level of “natural” energy arbitrage is likely through the peak shaving duty cycle. We have seen limited additional energy arbitrage value to date, but we are working with Tesla (the provider of Powerwall home battery systems and the PowerPack battery storage system at our Panton site) to automate battery responses to changes in LMP for the purpose of energy arbitrage. We are also collaborating with the firm Virtual Peaker toward this goal for battery storage and other responsive loads. Over time, it appears that increasing penetration of intermittent renewable generation in New England will lead to more significant fluctuations in LMPs (for example, more highs and lows) that will increase the opportunity for arbitrage over time.

This points to the fact that while we can identify and model the value that these various markets show us today, the upside value for energy storage is much greater in our opinion than the downside risk. We anticipate the growing need for fast-acting, flexible resources, not just for economic value, but also as the next level distribution resource, an emergency resiliency tool and beyond. As we put the finishing touches on this IRP, we are reminded of the devastation that the impact of climate change is having and how

severe our storms are becoming. Our customers just experienced one of our five worst storms in history during the last week of November. Although outages lasted as long as five days for some, a number of customers with Powerwall batteries were able to maintain backup power in their homes until power was restored. Now imagine if every single customer had a system like this. You cannot even begin to put a dollar value on customer satisfaction and security when it comes to having a backup resource during a major weather event like the one we just had. Not to mention the benefit of not having to fuel up a generator system, listen to the noise or run the risk of creating a carbon monoxide health hazard for your family. And equally important, when the storm is over and we are in the clear, we can go back to leverage the battery as a power supply and grid resource—again the ultimate in flexibility. The only question we ask now is how do we deploy, or cause to deploy, these systems much faster and to more customers.

An emerging issue for our portfolio is that the introduction of increasing volumes of intermittent solar, wind, and hydroelectric generation have increased the magnitude by which our energy supply (and therefore the open position that is exposed to spot market prices) fluctuates on an hourly or daily basis. We expect that the addition of battery storage will be complementary to an increasingly renewable supply, in part because of the inherent flexibility (for example, ability to ramp up charging or discharging quickly) of many battery systems. Storage could, for example, help us to begin to shift renewable output to hours of greater need (for example, solar output stored in a battery can be discharged during overnight hours to meet demand) as the scale of battery storage begins to increase.

Benefits and ISO-New England market opportunities will change over time and the flexibility of battery storage will enable them to play a part of our future strategy of minimizing net power costs for our customers. For example, over the next couple of years, changes to the ISO-New England operating reserve market will likely allow batteries to provide Ten Minute Non-Spinning Reserve; to the extent that the value from this market exceeds the value of any current battery uses, we may shift the operational duty cycles to participate in the Reserve Market, or possibly change the stack of benefits to include this market. ISO-New England has also begun to describe the need for a ‘ramping’ market, which would compensate resources that can respond quickly during key hours of the day where the New England load levels are somewhere in between the current level of resources and the need to turn on the next plant.

Battery storage systems can also benefit from the same federal Investment Tax Credit (ITC), that solar PV can receive, which is a further boost to the economics for Vermonters. Currently, to qualify for the ITC, a battery storage device must be collocated with a solar PV array and, for the first five years, at least 75% of charging energy must come from the solar unit. The taxpaying owner receives the equivalent

amount of the 30% ITC based on the charging percentage, so for example, if the plant just hits the 75% threshold for charging off of the solar, the owner will get 75% of the 30% ITC benefit, and up from there. It is important to note that the 30% ITC is scheduled to step down beginning in 2020 and will drop to 10% in 2022, making it significantly less valuable for projects. At the same time, market studies indicate that increasing industry scale—particularly driven by a shift in the automotive industry toward partially electric and all-electric vehicles—is likely to drive down the cost of battery storage options significantly over the next five years, which should more than offset the drop in the ITC.

In the long-term, battery storage will play a role in displacing a portion of fossil fired peaking units, especially those units that are inefficient and have high emission profiles (for example, CO₂ and Nitrogen oxides). These batteries can directly participate in the ISO-New England Capacity Market and will receive monthly payments based on seasonal capacity ratings or continue to act as a load reducers. Currently, the key obstacle to participation in the peaking capacity market is that any unit must, at a minimum, be able to run for at least four hours, and in many instances peaking units have been required to run for significantly longer periods. Currently, adding hours of discharge requires the addition of cells, with each incremental hour of capacity coming at a slight discount to the initial hours of capacity. If the declining cost trends—or potentially breakthrough technological developments—lower the cost of longer-duration storage, several of the potential use cases would be enhanced.

While the power market and transmission benefits of battery storage can cover most or all of the costs of some battery storage systems today, the appropriate pace and locations for deployment of battery systems is likely to depend strongly on the extent to which they can provide local grid benefits.

Categories of potential benefits include:

- Deferral or displacement of transmission or distribution infrastructure that would otherwise be needed to provide reliable service. To the extent that we are able to deploy a battery storage solution with a lower total net cost than rebuilding a substation or reinforcing lines to manage demand on a circuit or potential demand growth, there is a significant benefit for customers (for example, a less expensive solution creates less potential rate pressure).
- Management of voltage on the distribution system. If a battery system is well located, its inverters may also be available to provide voltage support that is needed—especially as the saturation of distributed generation resources increases.
- Grid resilience, whereby a local circuit (or portion) can be supported by a battery (potentially in combination with other local generation) during an outage of the

broader grid. We have engaged with consultants to fully analyze the relay and protection schemes required for safe and stable islanding. We have reached an agreement with Vermont Department of Public Service that we will file for a Certificate of Public Good (CPG) before it undertakes islanding capability projects, whether through an initial CPG filing for a project including battery storage or a secondary filing specifically for islanding.

- Increasing the hosting capacity of a distribution circuit (or increasing the feasible generation in an export-constrained transmission area), by charging during times of excess local generation. As Vermont charges toward not only meeting our comprehensive energy goals, but exceeding them, energy storage plays a critical role in managing the new demands that may exist from the strategic electrification of fossil-fuel-based energy systems.
- As a customer-sited resiliency and power quality tool. Many customers in the C&I space are susceptible to business losses caused by voltage fluctuations that occur when faults happen on the system. Even if the fault is 50 miles away on the transmission system, sensitive operations can still be affected, costing the customer significant downtime or lost product. The addition of storage can not only smooth out those fluctuations but also act as a complete emergency power source if a complete outage occurs. This creates a new resource for the customer and revenue source for all our customers. And as with all storage options, the systems can be utilized at the right times for other grid and power supply benefits.

Battery storage is an important component of our future strategy for meeting customer demand and managing net power costs that will largely be driven by advances in technology and declining prices as manufacturers continue to scale up to meet growing global demand. In the near-term, we will focus on stacking peak-shaving benefits and Frequency Regulation to support the development of our battery fleet. In the longer term, other uses will begin to supersede these stacked benefits, through such use cases as firming renewable generation and replacing fossil-fired peaking units. At the same time, we will also be working to identify opportunities to minimize costs for customers through deferring T&D upgrades and enhancing grid reliability through voltage support and islanding.

Storage Procurement Strategy (Memorandum of Understanding with DPS)

As part of the recent petitions before the PUC for CPGs for three Joint Venture Solar and Storage Projects (JV Projects) that feature battery storage, GMP and the DPS have agreed on a process and criteria for the selection of future storage projects greater than 1 MW. The agreement is captured in a Memorandum of Understanding filed in each permitting proceeding (the Storage MOU). This was done to address the DPS's concern

that the estimates regarding performance of these emerging battery strategies are more subject to risk than traditional resources. In the Storage MOU, a number of specific steps and actions for future storage procurements are outlined, including conducting system-wide analysis in consultation with the DPS, individual project analysis methods, and a least-cost evaluation process.

Among other details for these future procurements, the Storage MOU defines that this process will strive to utilize competitive procurements and will include evaluations of and details on:

- Economic benefits
- Distribution system benefits
- How the project facilitates integration of distributed energy resources
- The potential for third-party cost and benefit sharing
- Estimates for all expected costs to achieve the project's expected value streams
- Least-cost, best-fit alternatives analysis

Beyond this specific approach to evaluating and procuring storage established in our MOU, we also describe how other elements of portfolio design may impact or include storage as a supply resource for the portfolio and describe some of the key metrics that may guide the approach to adding resources from this supply category across the long-term planning horizon.

With this in mind, our strategy is simple: to continue driving the implementation of battery storage on the system in the right locations and through a mix of customer and third-party-owned resources, as well as direct GMP-deployed systems. When it comes to battery solutions, in the next planning period, we believe the strategy truly should be “all of the above” as we work to respond to the cost pressures, reduce carbon further, and deploy the most flexible resources possible. We look at energy storage as the new version of poles and wires and other traditional utility assets when it comes to managing the distribution system. This procurement will take many forms such as RFPs, the Bring Your Own Device program with a fixed offer pricing, and through other solicitations that stimulate the market.

Fossil-Fueled Generation

The oil- and gas-fired generators that we own or purchase from under long-term contracts provide only small amounts of energy—in recent years, less than one percent of our energy supply. Fossil-fueled energy can enter our energy mix indirectly, however, through the portions of energy that are purchased from the ISO-New England spot

market, PPAs that are not associated with specific generating units, or the sale of RECs we control. These portions of our energy supply are generally assigned attributes from the New England “system residual mix”, meaning the mix of generation attributes that is not retired by market participants to meet Renewable Portfolio Standards or other goals. As discussed throughout, we are intensely focused on lowering the carbon profile of our overall supply so we will continue to explore ways to mitigate any fossil-fuel-generated energy that is in our portfolio.

Natural Gas Generation

According to ISO-New England, natural-gas-fired generators set the energy clearing price in New England during most hours of the year, meaning that natural gas is typically the marginal fuel resource in New England. The price of natural gas-fired generation has moderated in recent years, with the exception of cold winter periods when pipeline capacity in New England is constrained. This has benefited our customers by putting significant downward pressure on energy spot market prices and expectations for prices in future years, putting downward pressure on the market price for forward energy purchases as well as the price at which existing generating plants may be available for sale. The substantial supply of efficient natural gas-fired generation also limits price volatility in the energy market during many hours of the year; this tends to be helpful to us because it limits the risk associated with reliance on intermittent renewable resources.

The fixed costs to construct, own and operate natural gas-fired generation also affect the FCM, since the estimated net cost of new entry (Net CONE) for new natural gas-fired capacity is used as a reference point to establish the FCM’s administrative demand curve. The profitability of existing natural gas-fired plants can also affect the supply of capacity in the FCM (through delisting decisions), and therefore FCM clearing prices.

Existing natural gas-fired capacity (through PPAs or purchases of ownership) could in theory be a viable source of stable-priced capacity and peaking energy for us. Because we already own a significant amount of existing peaking capacity, and there is a relatively ample supply of gas-fired energy in New England, we are not presently pursuing acquisition of any existing gas-fired capacity and we have not modeled it as an option to explore.

Peaking Resources

Conventional fossil-fuel-fired peaking facilities will continue to play a significant role in the region’s electricity market, providing both capacity and peaking energy for the foreseeable future. Because these resources tend to be fast starting and flexible, they can also provide operating reserves to the ISO markets, and can be supportive of greater

levels of intermittent generation in the region. In the context of the recent changes in the Forward Capacity Market (FCM) and the Pay-for-Performance program (PFP), existing peaking resources (like our oil-fired combustion turbine and diesel units) can also be a cost-competitive hedge against both capacity and energy prices. As a result, the Resource Plan considers the role of conventional peaking resources continuing in our future portfolio.

Oil and Coal Generation

Oil- and coal-fired generation has been declining in New England for years, displaced largely by a combination of natural gas-fired generation and renewables. Coal-fired generation is not considered as a potential resource. New oil-fired generation is only considered as a potential local peaking resource, which would likely generate only occasionally and would not provide a meaningful portion of our energy supply.

Nuclear Generation

Our ownership share in Millstone Unit 3, along with our long-term PPA from NextEra Seabrook, provide roughly 14% of our annual energy requirements from nuclear power. These sources feature relatively stable costs, and they help keep our emissions profile well below the New England average. This fraction of nuclear energy is far below our historical level of nuclear reliance, which exceeded 40% during the past decade, when we relied on the Vermont Yankee plant for a third or more of our energy.

To our knowledge, no new nuclear development is taking place in New England, and in fact a number of nuclear resources in New England and the rest of the Northeast are expected to retire in the next several years (for example, Pilgrim in Massachusetts and Indian Point 2 & 3 in New York). Under the RES framework, it is expected that most new long-term sources entering our portfolio will be renewables, and our portfolio already features a substantial degree of long-term price stability. As a result, we are not presently seeking to add more long-term nuclear power purchases to the portfolio (and such purchases are not evaluated as potential resources in Chapter 8: Portfolio Evaluation). We have purchased nuclear attributes on a short-term basis in combination with forward energy market purchases, to stabilize near-term energy costs without absorbing the relatively high emission profile of the New England system residual energy mix.

SHORT-TERM CONTRACTING STRATEGY

Many elements that make up the total cost of power are subject to changes in market prices that can result in significant cost variability over annual, monthly, or even hourly durations. Since our long-term supplies typically feature operating profiles that are not intended to perfectly match short-term energy requirements, there are often periods where we (for some fraction of our power needs) are exposed to short-term market or spot market outcomes. To address the cost uncertainty presented by these exposures, we use fixed price short-term transactions (that is, “forward” sales or purchases) in the wholesale energy, capacity and renewable markets to achieve more stable outcomes for the near-term cost of purchased power. This stability derives from locking in fixed pricing for specified volumes in advance of delivery, as well as from matching the size of the transactions reasonably closely to our forecasted needs. Short-term forward transactions therefore protect us and our customers from having to buy or sell large volumes at volatile spot market prices, while limiting the terms of these transactions (and regularly replacing them over time at then-current market prices) allows this component of our portfolio to follow long-term market trends and will continue to be an important strategy in our power supply hedging portfolio.

Open Positions Managed with Short-Term Transactions

Open positions are volumes within the major supply categories (energy, capacity, RECs) that are associated with an exposure to variable pricing outcomes, because our committed supply and requirements are not matched for a period of time. Broadly, these three products make up a great deal of the costs that any load serving entity incurs to serve customers. In each of these three product categories where we have open positions, there are different actions and time frames over which their potential variability in cost or revenue is managed.

For energy, by design, our committed long-term resources several years prior to delivery are typically significantly less than customer requirements on an annual basis, with the intent to fill the open positions through short-term purchases in advance of delivery. We strive not to fill all of our forecasted needs with long-term commitments (that is, we choose to leave a sustained open position, to be filled closer to delivery) for a few reasons:

- Limit the extent to which our power costs may become disconnected in the long term from those of utilities in neighboring states that generally buy a greater portion of their needs in the short-term markets;

- Leave flexibility to procure new longer-term supply sources (particularly ones that support other strategic goals such as RES compliance) that may not be specifically anticipated today; and
- Limit the extent to which the portfolio could become substantially imbalanced in the event that retail load requirements decline relative to current projections.

We approach the capacity component of the portfolio in the same way, with the goal of meeting most (but not all) of our forecasted needs through stable-priced long-term sources. In the next several years, we therefore have a forecasted open (short) capacity position (typically 200 to 300 MW) that is available to be purchased through short-term bilateral purchases or through monthly FCM transactions. Although the Vermont RES does not apply directly to capacity, we are looking at the opportunities to procure more capacity from local, distributed resources such as energy storage or even third-party aggregators that provide this as a service, much as we would approach Tier II under the RES. When coupled with the benefits of adding storage in certain locations, this could be a powerful tool. We expect to carve out some fixed portion of our open capacity position and utilize it as an in-state resource procurement mechanism to further this possibility.

We receive (through long-term PPA sources and owned sources) a substantial inventory of RECs that are eligible for Class 1 RPS compliance in neighboring states. Unless Class 1 REC prices fall to unusually low levels (see Chapter 8: Portfolio Evaluation for further discussion), it will likely be cost-effective to continue sell those RECs (and use the revenues to reduce our net power costs and electric rates). In our experience, there are few buyers in New England who are interested in purchasing Class 1 RECs for terms longer than 4 years, largely because the ultimate buyers for RPS compliance in neighboring states have only limited long-term retail load commitments from retail customers. The vast majority of our Class 1 REC holdings have not been sold on a long-term basis, and are therefore available to be sold through shorter-term forward sale transactions.

Design of the Short-Term Trading Program

Short-term transactions to address market exposures from the open positions are made with the fundamental goal of limiting our customers' exposure to short-term market energy prices (or spot market prices) providing greater stability in near term power supply costs and retail rates. Other goals include:

- Low net cost for customers. We presently seek to do this by typically using low-cost transaction types for each product—this tends to mean transactions that are actively traded in the market (not requiring a substantial illiquidity premium); transactions for

which natural hedgers (for example, power plant owners selling energy and capacity, competitive retail suppliers buying RECs) may logically match our needs; and transactions that do not require the counterparty to provide optionality or insurance features that would require a significant price premium (above reasonable current expectations for spot market outcomes).

- For large open positions, avoid purchasing and selling all of the open position at one time, based on a single set of market conditions. We typically accomplish this by buying and selling our forecasted open position through several transactions over time. It may also be possible to accomplish the same effect through bilateral transactions that lock in prices at multiple pricing dates.

By combining these goals, we maintain a program for each product category to best address the unique characteristics and limitations in each product category and market. The key elements in these programs revolve around tracking the available hedging tools and market conditions surrounding each product, and then establishing the appropriate transaction timing, duration, and frequency to achieve the best outcomes for customers (that is, limiting price uncertainty at lowest practical cost).

Products for Short-Term Hedging

In the short-term hedging program, our primary focus is addressing market exposures using physical supplies that settle within the established markets. The products that make up this program center on energy, capacity and renewable attributes because they represent our largest short-term uncertainty and because these marketplaces tend to be the most mature and feature meaningful numbers of participants (for example, they allow for more competitive and transparent outcomes).

Energy

We will discuss energy first because it typically represents the single largest cost exposure for any load serving entity in the region. If we do not purchase our open energy position in advance, those volumes will ultimately be purchased in the spot market (DA and RT energy markets) on an hourly basis. Our current strategy focuses primarily on purchasing (or less often, selling) fixed blocks of energy at fixed prices; this is a prime example of a low-cost product. In the energy short-term program, we generally purchase firm energy⁵² (not unit contingent) from creditworthy sellers, and settle them at the ISO-New England internal hub to maximize liquidity and attract the widest seller interest. Unless the contracts also include emissions attributes associated with particular generation sources,

⁵² GMP would also consider plant-contingent purchases, depending on factors including the transaction size, source unit(s), and pricing.

they are considered for purposes of describing the fuel mix and air emission profile of our power supply to carry an emissions profile of the “system residual” mix.

In planning short-term transaction volumes, we focus first on achieving balance between energy needs and supply for each year as a whole; we also use specific transaction volumes to balance forecasted supply and requirements on a monthly basis. To determine the profile of the energy to purchase (for example, annual or monthly on-peak or off-peak blocks, or all-hours baseload) and the duration of these purchases, we monitor and update projections of future energy requirements for periods ranging from one month to five years in advance of a delivery period. We also check for any recent or expected changes in our committed supply sources (for example, expirations of existing resources, additions of new supply sources, or pace of growth in net metering volumes).

The resulting pattern of committed energy supply sources and forecasted demand removes the vast majority of our potential exposure to sustained market price changes. This forward purchasing approach yields a large degree of short-term stability in our net energy costs, but it does not fix them entirely. Variations in electricity demand and generation (particularly intermittent renewable sources) over shorter time frames from an hour to a month sometimes present significant short-term cost variations for the power portfolio. These short-term fluctuations tend to substantially offset each other over time, however, and it is generally not practical to eliminate them without using more costly products that would increase our expected power costs.

Capacity

Fixed-volume forward purchases of capacity share the low-cost characteristics for energy, and are our primary short-term hedging tool for stabilizing the cost of capacity. Such transactions typically take the form of an exchange of capacity from a specific generating unit, a transfer of a portion of our capacity obligation quantity to the seller, or a self-supply transaction to meet a specified volume of our capacity needs. Capacity is settled on a zonal basis in the FCM, with our load being located in either the Rest of Pool or Northern New England Zone. Because ISO-New England reviews the definition of capacity zones from auction to auction, the appropriate zone(s) upon which to base short-term capacity purchases can change over time.

RECs

State-administered RPS compliance markets are the overwhelming source of demand for Class 1 RECs. The primary transaction structure in this market is fixed volume, fixed price blocks for calendar year vintages (the period of obligation for most state RPS programs), with quarterly delivery of RECs through the NEPOOL GIS.

Aside from the direct, physical supply hedges, there are also indirect or financial hedging products that reside outside of the ISO-New England market or the NEPOOL GIS (renewable attribute exchange). Often this type of financial hedging involves an exchange of financial value instead of the actual physical delivery of a product⁵³ and can require special, derivative accounting treatment. In this financial hedging category there are also products available that resemble insurance policies, where in exchange for a premium payment a specific exposure to some element of supplier risk can be limited.

Transaction Timing and Durations

Within the hedging program our general goal is to lock in fixed prices for short-term transactions over several years in advance of delivery. The general goal is to diversify the timing of these purchases (so as not to “put all of our eggs in one basket” by purchasing an entire open position at one time, under one set of market conditions). As a result, we make energy and capacity purchases regularly on a layered basis with terms up to five years ahead of the delivery period; we use a similar approach for REC sales. The timing of transactions for different products tends to vary somewhat based on structural differences in the markets for those products.

For REC sales, the regional Class 1 RPS market is not as large or as liquid as the energy market; in our experience, typical transaction sizes range from a few thousand MWh up to 50,000 MWh. Our REC inventory for a given vintage year has been at least 600,000 MWh in recent years, so it is not practical to sell this inventory all at once. Further, if we attempted to aggressively sell a large fraction of inventory over a short period (for example, a month or two), we believe that we would put meaningful downward pressure on the regional market price. We therefore seek to implement forward REC sales regularly over approximately a four-year period. Buyer interest in REC purchases for three or more years in advance tends to be modest, so the timing of forward sales sometimes depends on market availability. Short-term variations in the production of our sources (mostly wind, solar, and hydroelectric) causes some variation in the supply of RECs that we have to sell for any given vintage year; these variances are typically managed in the final few quarters of each vintage year.

⁵³ For example, in a capacity contract for differences the buyer and seller might exchange no capacity, each settling their positions in the annual FCA. The seller would pay the buyer to the extent that the FCA clearing price turned out higher than a negotiated notional price for capacity; the buyer would pay the seller to the extent the FCA clearing price turned out lower.

5. Our Increasingly Renewable Energy Supply

Short-Term Contracting Strategy

For capacity, the FCM does not have a typical “spot market” (as the energy market does) where prices are variable up to the time of delivery. Instead, the final pricing event that we seek to hedge against is the annual capacity auction (conducted in winter), which largely determines the price of capacity to load three years into the future. Since that period we are hedging against is already three years into the future we tend to transact less frequently for any individual capacity year. In our experience capacity sellers are most interested in trading during the few months leading up to the next annual auction, so we tend to solicit forward capacity proposals in the November to December time frame.

We start with a benchmark expectation of implementing forward purchases and sales over a roughly even pace over several years; the particulars of transaction timing vary by product, along with the magnitude of our expected open position.⁵⁴ Notably, we consider accelerating the pace of transactions for each product during times when available prices are perceived to be relatively attractive, with the goal of reducing the expected cost of energy and capacity (and maximizing the expected revenue from REC sales) to benefit our customers. Conversely, we may slow our transaction pace if we perceive available market prices as less favorable,⁵⁵ or if conditions within our resource portfolio have become more uncertain.

To support the choice of transaction durations and pace for short-term transactions, we regularly collect and review market price indications (for example, broker indications for standardized energy forward contracts, and for REC pricing). We also review information (for example, trade press, consultant reports and forecasts obtained via subscription, interviews of consultant experts) that address in detail regional supply, demand, and other factors that affect price formation. We use these sources to form our view of the relative attractiveness of current markets, and how forward market pricing may move over time.

⁵⁴ For example, if our forecasted short energy position for a given month is small relative to our load requirements and relative to liquid transaction sizes in the regional market, it makes sense for us to purchase the entire (small) need in a single transaction. Spreading out the purchase over many (very) small transactions would incur additional administrative costs, and likely a higher price because of an “odd lot” or illiquidity premium.

⁵⁵ For example, in 2016, we accelerated its forward REC sales for the 2018 and 2019 vintages, when prevailing forward prices were \$30 per MWh or more, and our market intelligence indicated the potential for an emerging regional surplus and potentially substantial price declines. Since forward REC prices have fallen substantially during 2018, we have slowed its pace of forward REC sales for the next few years.

Available Short-Term Procurement Methods

One of the most significant considerations influencing our choice of a procurement method in any particular hedging activity is ensuring a competitive and low-cost result (or greatest value result in the case of sales). There are four primary methods for procuring short-term hedges.

Broker Services. In both the energy and renewable attribute markets there are firms that specialize in matching buyers and sellers for commissions. Some brokers publish regular trading quotes to help inform clients of market conditions. Brokers charge a small fee for this service; advantages of brokered transactions include regular market monitoring on our behalf, access to multiple potential buyers, and anonymity for us (until the buyer and seller are matched for a transaction).

GMP-Initiated Request for Proposals (RFP). Typically a targeted request from GMP directly to active participants in the market. In this low-cost method, we typically provide a product term sheet specifying criteria for offers and a date for offers and awards.

Auction Events. Firms offer fee-based online platforms where a live event can be scheduled to allow potential suppliers an opportunity to compete with some visibility on resulting awards and prices at the conclusion of the event.

Counterparty-Initiated Request for Proposals. From time to time a supplier or purchaser (most often of RECs) will include us on their direct request for offers and provide specific criteria for their needs and a schedule for participation and award.

Within these formats, there is no single preferred method, and the detail and formality of each method used can vary considerably depending on the nature and significance of the transaction. Requests with shorter, more standardized terms will tend to have less administrative burden and resolve quickly (for example, within hours) whereas longer-term and larger procurements can potentially resolve over weeks from the date of the solicitation, to allow time for thorough evaluations.

Proposal Evaluation and Selection

In deciding outcomes of a solicitation to implement an element of the short-term portfolio hedging programs, we seek to ensure that a selection of an offered product meets the standards and goals established for each solicitation. The evaluation steps can vary considerably depending upon the type of solicitation and the overall significance of the procurement.

In the broadest terms this variability in evaluation and selection tends to fall along a continuum where the shortest-duration, lowest-impact transactions are assessed rapidly using a limited set of benchmarks (market quotations) to longer-duration, more economically significant proposals that may be evaluated against a number of screening criteria and involve the use of outside consultants with uniquely specialized knowledge of the product.

Aside from evaluation factors that test competitiveness and the lowest cost (or highest value) features of a new short-term proposal, we also take into consideration certain risk factors to reduce the likelihood of negative outcomes during the delivery period of the hedge. The most common example of this is the application of creditworthiness requirements and volume concentration limits.

Ultimately in each solicitation awards are made to the extent that offers achieve the goals of the solicitation and the leading suppliers meet our contracting requirements.