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VERMONT LMP FORECAST FOR THE 2022 IRP

DECEMBER 2021

PREPARED FOR
Vermont Electric Cooperative

PREPARED BY
Daymark Energy Advisors

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LIST OF ACRONYMS

83C-III	Section 83C of Chapter 169 of the Acts of 2008, as amended, third procurement
AEO	U.S. EIA's Annual Energy Outlook
BTM PV	behind-the-meter solar photovoltaic
CASPR	ISO New England's Competitive Auctions with Sponsored Policy Resources
DSM	demand-side management
EE	energy efficiency
EIA	U.S. Department of Energy's Energy Information Administration
ESR	energy storage resource
FCA	ISO New England Forward Capacity Auction
FCM	ISO New England Forward Capacity Market
GWSA	Massachusetts Global Warming Solutions Act
HQ	Hydro-Québec
HQICC	Hydro-Québec Interconnection Capability Credits
ICR	Installed Capacity Requirement
ISO New England	Independent System Operator of New England
LCR	local sourcing requirements
LMP	Locational Marginal Price
MCL	maximum capacity limits
MW	Megawatt
net CONE	net Cost of New Entry
NMM	Daymark's Northeast Market Model
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	operation and maintenance
OSW	offshore wind
PDR	passive demand resources
PLEXOS	PLEXOS® software platform licensed through Energy Exemplar
REC	renewable energy certificate
RFP	request for proposals
RGGI	Regional Greenhouse Gas Initiative
ROP	Rest of Pool
RSP	Regional System Plan
SEMA	Southeastern Massachusetts zone
STEO	U.S. EIA's Short-Term Energy Outlook
WCMA	Western/Central Massachusetts zone

DISCLAIMER

The analyses supporting the results involve the use of assumptions and projections with respect to conditions that may exist or events that may occur in the future. Although Daymark Energy Advisors has applied assumptions and projections that are believed to be reasonable, they are subjective and may differ from those that might be used by other economic or industry experts to perform similar analysis. In addition, actual future outcomes are dependent upon future events that are outside Daymark Energy Advisors' control. Daymark Energy Advisors cannot, and does not, accept liability under any theory for losses suffered, whether direct or consequential, arising from any reliance on this presentation, and cannot be held responsible if any conclusions drawn from this presentation should prove to be inaccurate.

I. INTRODUCTION

Daymark Energy Advisors (Daymark) performed an energy market analysis in support of the Vermont Electric Cooperative (VEC) 2022 Integrated Resource Plan (IRP). The analysis uses Daymark's Northeast Market Model (NMM) to forecast Vermont zonal Locational Marginal Prices (LMPs) for the 20-year study period 2023 – 2042.

Recognizing uncertainty inherent in any forecast of future market conditions, Daymark also provided reasonable high- and low-price scenarios. The variance in the three different cases is driven by changes in assumed natural gas and CO_2 prices. Energy prices are very sensitive to natural gas and CO_2 price assumptions and these assumptions are also subject to a large amount of uncertainty, which is why they were varied to create the three sensitivities. The variation in natural gas and CO_2 price assumptions is summarized in the table below. More details on these inputs and other model inputs are provided in the following section. More details on the results are provided in Section IV.

Table 1: Variations in Key Assumptions for Reference, Low and High Cases

INPUT ASSUMPTION	LOW	REFERENCE	HIGH
Natural Gas Price (Henry Hub)	Forward quotes	STEO/NYMEX (2022-23) + AEO long-term trend	[Same as Reference]
Natural gas price (AGT Basis)	[Same as Reference]	1yr average forwards to 2025, hold constant real; winter reduction to 25% by 2028	60-day average forwards
CO_2 Price	RGGI only	RGGI + Fed program in 2028	[Same as Reference]
New HQ Tie	NECEC in 2024	NECEC in 2027	None

This report describes the energy market analytical methodology, provides details on key model inputs and assumptions, and shows Vermont zone prices for Reference, High and Low Cases. Annual average prices are shown for each case below.

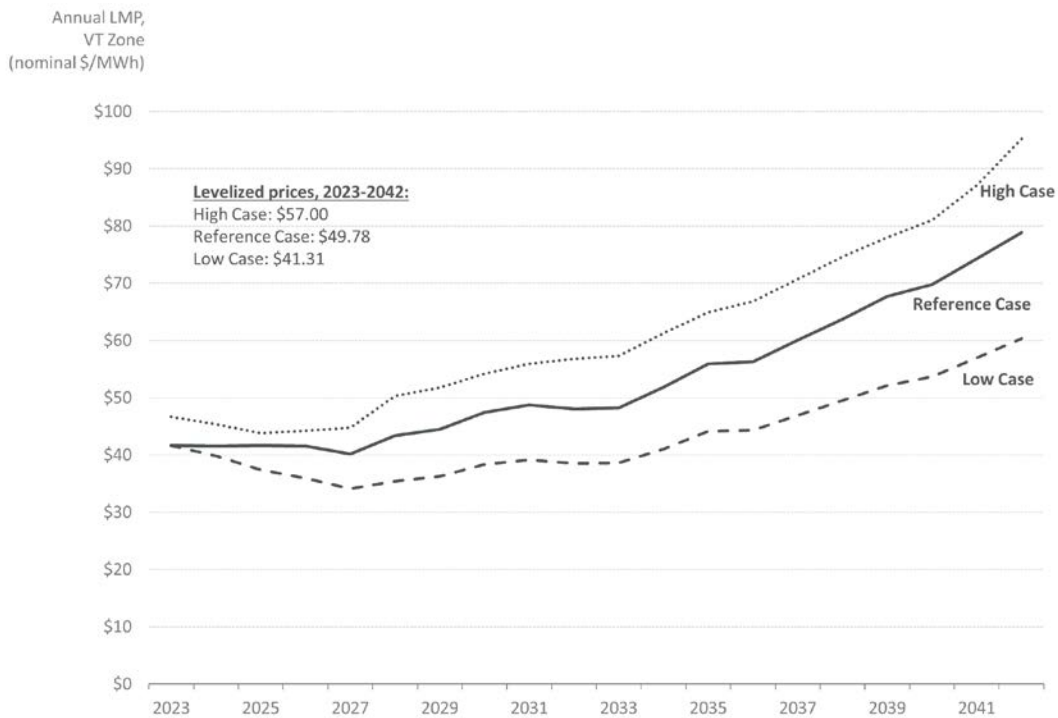

Figure 1: **Vermont Zonal Prices for Reference, High, and Low Cases**

II. NORTHEAST MARKET MODEL OVERVIEW

The Daymark Energy Advisors Northeast Market Model (NMM) uses an hourly chronologic electric energy market simulation model based on the PLEXOS® software platform licensed through Energy Exemplar (PLEXOS). The model provides a zonal representation of the electrical system of New England, with market-based simulation of interchange opportunities with surrounding control areas.

The underlying technology, PLEXOS, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. The PLEXOS model captures the dynamics and economics of electricity markets.

PLEXOS realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management (DSM) impacts, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses.

The NMM uses a New England carve-out from a comprehensive database representing the entire Eastern Interconnect (the North American interconnected power system east of the Rocky Mountains), including representations of power generation units, zonal electrical demand, and transmission configurations. Daymark constructed this New England-focused database from a number of established sources of information, including:

1. A comprehensive database issued by Energy Exemplar, the developer of PLEXOS
2. S&P Global Market Intelligence
3. The U.S. Department of Energy's Energy Information Administration (EIA)
4. The Independent System Operator of New England (ISO New England)
5. The New York Independent System Operator (NYISO)
6. The New York Mercantile Exchange (NYMEX)

Daymark supplements the Energy Exemplar database with custom updates and revisions of key inputs for the New England and interchange opportunities with neighboring control areas.

A. System Topology

The NMM is a zonal model where each defined zone represents a "bubble" of load and generation. Transmission is represented as single composite links between zones with constraints on certain combinations of links to realistically represent the interfaces. Key attributes that can be defined for each individual link are wheeling costs, transfer losses, and transfer capability (in MW). The topology of ISO New England and contiguous areas within the NMM are shown in Figure 2, below.

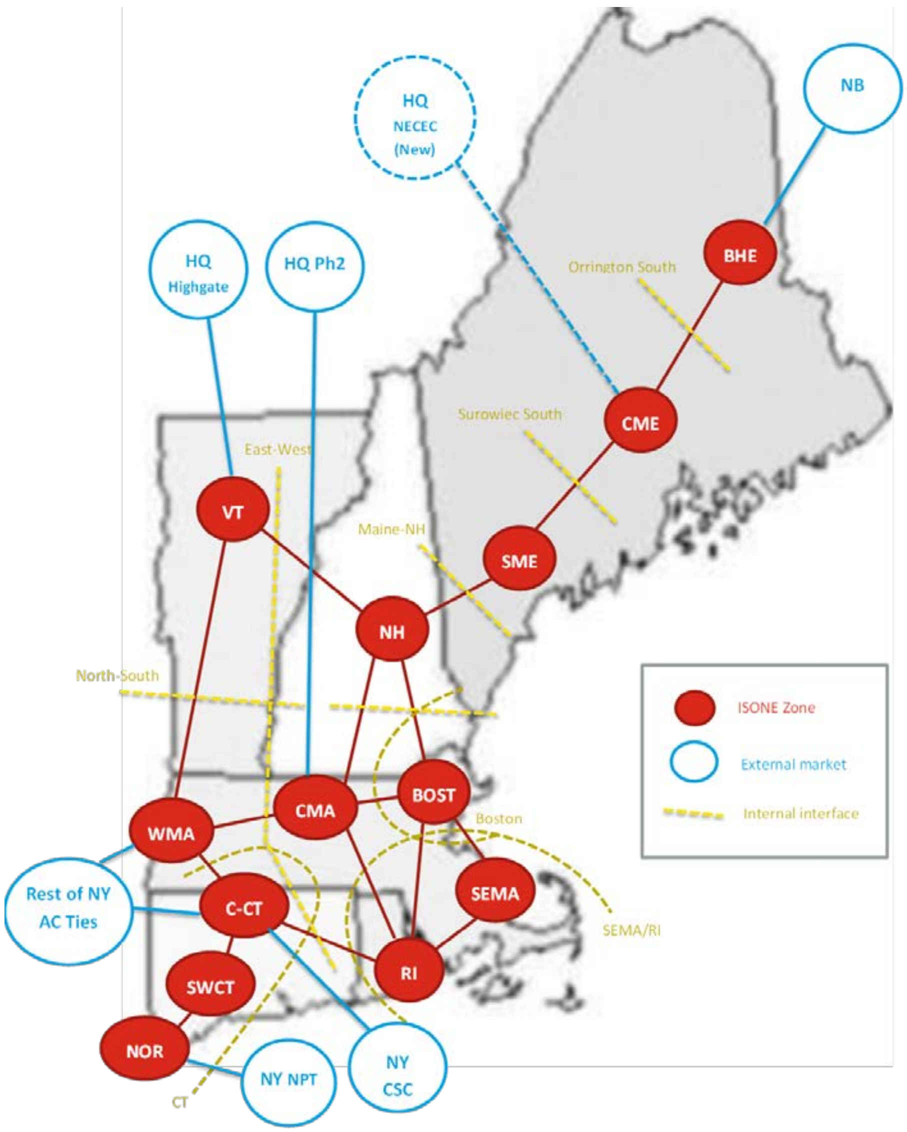

Figure 2. **NMM Topology: ISO New England and regional interconnections**

In addition to individual links, NMM also defines constraints over multiple links to represent interface limits. The following tables show how ISO New England external and internal interface limits are represented in the NMM. Key data sources include the ISO New England transmission transfer capabilities assumptions for Forward Capacity Auction 16[1] and the NYISO 2018 Reliability Needs Assessment Report.[2]

The New England Clean Energy Connect project, winner of the Massachusetts Section 83D Clean Energy Request for Proposals, is expected to come online no earlier than 2024, bringing 1,200 MW of hydroelectric power from Hydro-Québec to the Central Maine zone and increasing the transfer limit over the Surowiec South interface by 1,000 MW. NECEC developer Avangrid recently halted construction at the request of the Maine Governor after a statewide referendum passed in November 2021 opposing the project. The project, originally scheduled to come online in 2023, now faces an uncertain future. The Reference Case assumes the project comes online with a 4-year delay in 2027. The Low Case assumes only a 1-year delay to 2024, and the High Case assumes no new tie lines at all.

We assume the addition of a 1,200 MW Bourne-to-Mystic line currently being studied in the ISO New England cluster study, which is assumed to increase SEMA/RI export limits by 1,200 MW in 2031. All other changes in topology during the study period are consistent with the FCA 16 study.

[1] ISO New England Presentation (3/17/2021). *Forward Capacity Auction 16 Transmission Transfer Capabilities and Capacity Zone Development*. https://www.iso-ne.com/static-assets/documents/2021/03/a8_fca_16_transmission_transfer_capability_and_capacity_zonal_development.pdf.

[2] New York ISO (10/16/2018). 2018 RNA Report. See pp 34-36. https://www.nyiso.com/documents/20142/2248793/2018-Reliability-Needs-Assessment.pdf.

Table 2. External Interface Limits

NAME	ISO-NE ZONE	EXTERNAL ZONE	LIMITS (MW) EXPORT	IMPORT
New Brunswick-New England	BHE	New Brunswick	-------	1,000
HQ-NE (Highgate)	VT	HQ	-------	200
HQ-NE (Phase II)	CMA	HQ	-------	1,400
HQ-NE (NECEC)	CME	HQ	-------	0 / 1,200 [a]
Cross-Sound Cable	C-CT	NYISO-K	330	330
Northport-Norwalk Cable	NOR	NYISO-K	404	414
AC Ties	C-CT	NYISO-G	600	600
	WMA	NYISO-F	800	800
	VT	NYISO-D	-------	-------
AC Ties to New York (including Northport)			1,400	1,400

Notes: (a) Increase due to NECEC project in the Reference and Low cases. Increase occurs in 2027 for Reference Case and 2024 for Low case.

Table 3. Internal Interface Limits

INTERFACE NAME	ZONE A	ZONE B	LIMITS (MW) A TO B	LIMITS (MW) B TO A
Orrington South	BHE	CME	1,325	1,325
Surowiec South	CME	SME	1,500 / 2,500 [a]	1,500 / 2,500 [a]
Maine-New Hampshire	SME	NH	1,900	1,900
North-South	VT	WMA	2,725	2,725
	NH	CMA		
	NH	Boston		
	VT	WMA		
East-West	VT	NH	3,500	2,200
	WMA	CMA		
	C-CT	RI		
Boston Import	NH	Boston	5,700 / 5,250 [b]	5,700 / 5,250 [b]
	CMA	Boston		
	RI	Boston		
	SEMA	Boston		
SEMA/RI Export	RI	C-CT	3,400 / 4,600 [c]	1,280 / 1,800 [a] / 3,000 [c]
	RI	CMA		
	RI	Boston		
	SEMA	Boston		
Connecticut Import	RI	C-CT	3,400	3,400
	WMA	C-CT		
	NYISO-G	C-CT		
	NYISO-K	NOR		
SW Connecticut Import	SWCT	C-CT	2,800	2,800
	NYISO-K	NOR		

Notes: (a) Increase in 2023

(b) Decrease in 2024 associated with updated load assumptions, NNE-Scobie transfer capability and retirement of Mystic 7,8 &9.

(c) Increase in 2031 with addition of 1200MW Bourne-Mystic line

III. KEY NMM INPUTS

This section provides details on the key modeling inputs and assumptions used in the NMM energy market analysis.

A. Load

The load forecast used in the NMM for New England is based on the ISO New England load forecast for the 2021 CELT report. Since the zones modeled in the NMM align with the Regional System Plan (RSP) zones, we used the forecast values by RSP zone directly from the CELT report.

For the forecast years through 2030, the 2021 CELT report forecasts gross peak and energy load, as well as peak and energy load net of energy efficiency (EE)[3] and behind-the-meter solar photovoltaic (BTM PV) generation. ISO New England's passive demand resources (PDR) forecast in the CELT report includes estimates based on both the resources cleared in the ISO New England Forward Capacity Market (FCM) and the anticipated load reductions from state-sponsored EE and demand response programs. For extrapolation in modeled years after 2030, gross load is assumed to grow at the compound annual growth rate from 2026-2030. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2030 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.

Figure 3 below shows the 2021 CELT-based forecasts of gross and net coincident peak demand and Figure 4 shows the gross and net energy load for the New England Control Area.

[3] ISO New England refers to EE as "passive demand resources" (PDR).

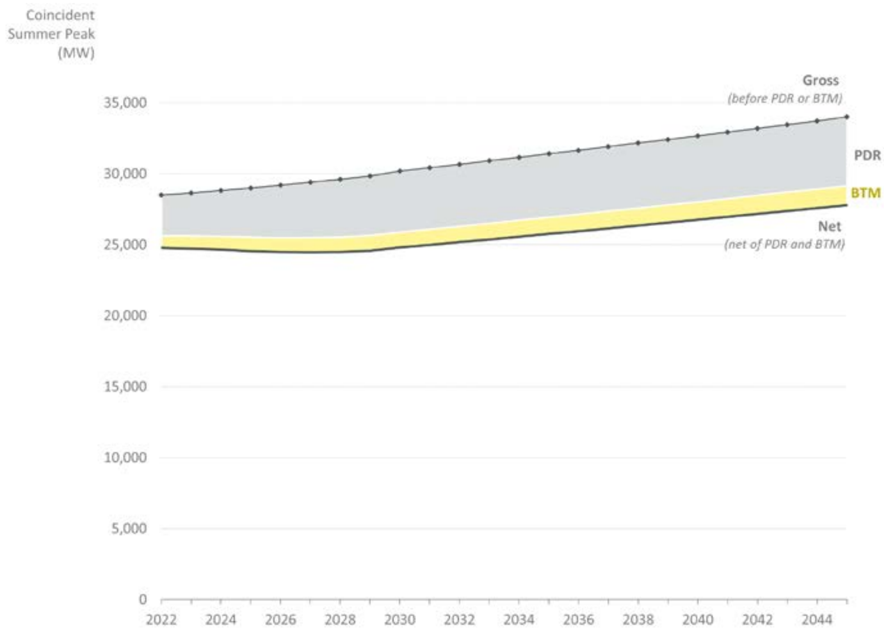

Figure 3. New England Coincident Peak Demand, Gross, Net of Passive Demand Resources (PDR), and Behind-the-Meter Solar (BTM)

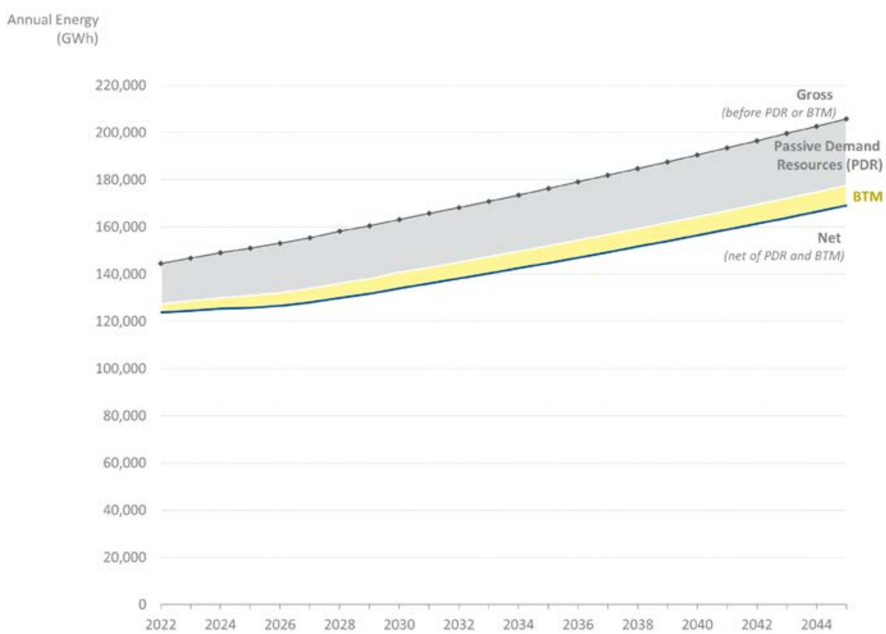

Figure 4. New England Energy Load, Gross Net of Passive Demand Resources (PDR), and Behind-the-Meter Solar (BTM)

B. Fuel Prices

Fuel price projections are key assumptions for the NMM and are subject to a large amount of uncertainty. As a key component of dispatch cost, fuel prices drive price formation and regional market dynamics. In the NMM production cost model, each generator is assigned a fuel price based on the type of fuel, unit type, and plant location.

The ISO New England market is currently dominated by natural gas generation and that will likely remain the case throughout the study period. Therefore, the natural gas price assumptions are a critical driver to our modeling and results.

The price of natural gas for each New England generator is constructed according to the following basic formula for a given month, m:

$$\mathbf{DP_m = HH_m + IP_m + p}$$

Where:

DP	=	Delivered price to generator
HH	=	Henry Hub price
IP	=	Index price basis differential from Henry Hub to Algonquin Citygate
p	=	Peaking unit adder

The peaking unit adder is used for a few inefficient generators that are only likely to operate on peak demand days when daily gas prices are likely higher than the monthly average.

The derivation of each of the remaining components of the equation above are explained in the following sections.

Henry Hub

Daymark used the U.S. EIA's 2021 Annual Energy Outlook (AEO) and December 2021 Short-Term Energy Outlook (STEO) Reference Case forecasts of Henry Hub natural gas commodity prices. The AEO is a publicly available long-term annual forecast and STEO is a publicly available short-term monthly forecast; both are commonly used in the energy industry.

Reference Case: The Reference Case combines the AEO2021 trends with updated annual forecast from December-2021 STEO. This case relies on the STEO through 2021, then a blend of STEO and NYMEX forward quotes in 2022, and then grows at 2.9% (nominal), which is the AEO2021 compound annual growth rate to 2050. This approach combines short term price outlooks based on more recent STEO modeling and forward market data with longer-term fundamental trends captured in the AEO.

Low Case: The Low Case relies on recent NYMEX future quotes to 2027, then holds 2027 prices constant in real dollars for the rest of the study period.

High Case: same as the Reference Case.

Figure 5 shows the Reference Case Henry Hub prices.

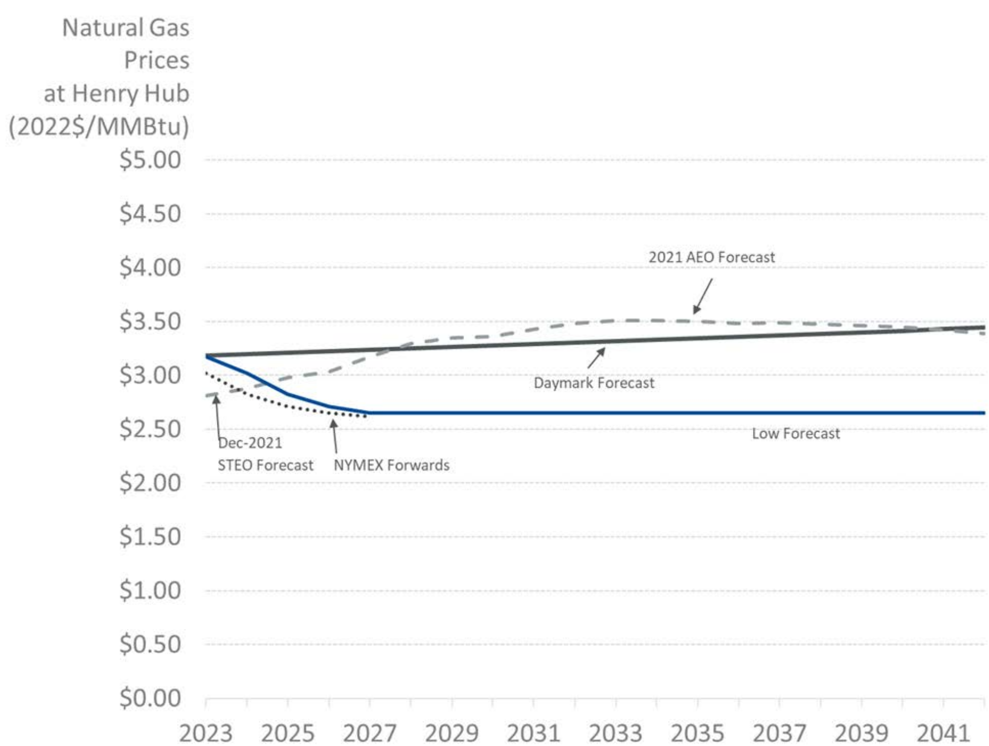

Figure 5. Henry Hub Gas Price Assumptions with key reference sources (2022$/MMBtu)

Region-specific gas indices

The region-specific index most relevant to New England represented in the NMM is Algonquin Citygate. Basis differential prices to Henry Hub Prices are derived from Natural Gas Intelligence (NGI) market futures quotes, and then held constant in real dollars after 2025. The NGI future quotes are obtained through MarketView by Enverus.

Reference Case: NGI futures used for the Reference Case are an average of quotes from 12 months of trading days through December 2021, for delivery months through 2026. A discount was applied to winter month pricing (December through March) reflecting reduced electric generation demand for natural gas, escalating from 5% in 2024 to 25% in 2028 and through the rest of the study period.

Low Case: same as the Reference Case.

High Case: The High Case is based on an average of just 60 trading days, reflecting a recent sharp increase in basis futures pricing, particularly in early years. No winter discount is applied.

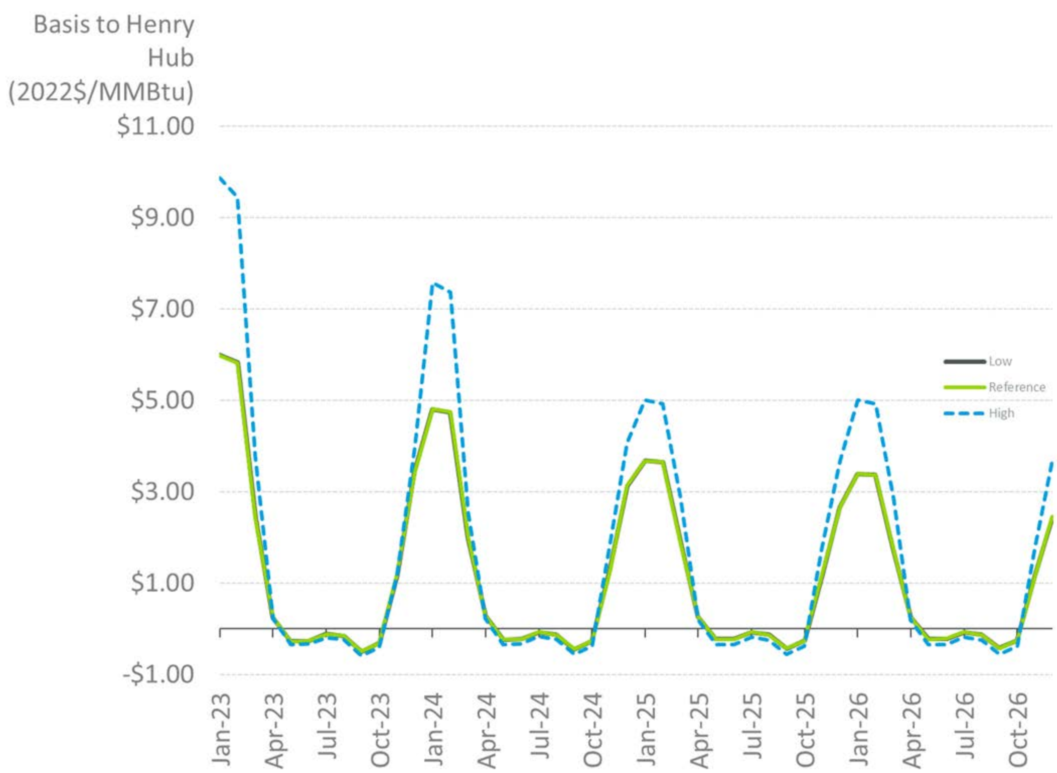

Figure 6. Algonquin CG Monthly Basis (2022$/MMBtu)

New England delivered gas prices

The following chart shows annual average gas prices delivered to New England for baseload generators for the Reference, High and Low Cases. These prices do not reflect peak day adders for some less efficient “peaker”-type units.

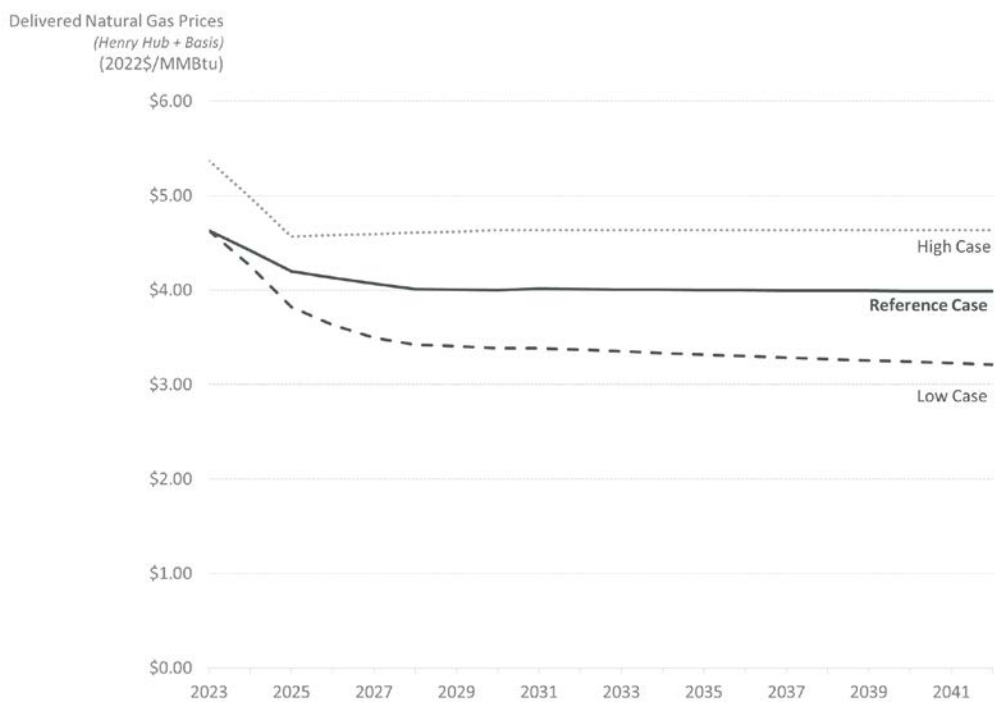

Figure 7. Delivered (Algonquin Citygate) Natural Gas Price Comparison (2022$/MMBtu)

C. Greenhouse Gas Emissions

The NMM incorporates emission prices into the production cost, commitment, and dispatch of units.

Our New England Base Case incorporates the impact of the 2017 IPM RGGI Update,[4] along with the assumption that federal carbon regulations will complement the RGGI program starting in 2028.

All New England states currently participate in the Regional Greenhouse Gas Initiative (RGGI) program, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. A RGGI-commissioned study of the Updated Model Rule projects that emission

[4] Source: RGGI Program Review, RGGI, Inc. Available at: https://rggi.org/program-overview-and-design/program-review

allowance prices will rise from $5.51 per ton in 2017 to $13.51 per ton (nominal $) in 2031. The NMM incorporates this updated outlook on RGGI allowance prices. Actual RGGI auction prices have tracked closely to the forecast, averaging $5.43/ton in 2019 and $6.41 in 2020.

The Reference Case and High Case both assume a significant increase in policy stringency in 2028. This may reflect the implementation of a federal program to complement RGGI, or a revised RGGI model rule that tightens limits in the existing RGGI program. The price outlook for this scenario is based on the High Sensitivity case from RGGI's 2017 study, which assumes, among other things, implementation of a national program.

The Low Case assumes the RGGI Updated Model Rule base forecast, extrapolated through the whole study period.

The CO_2 price outlook is summarized in Figure 8.

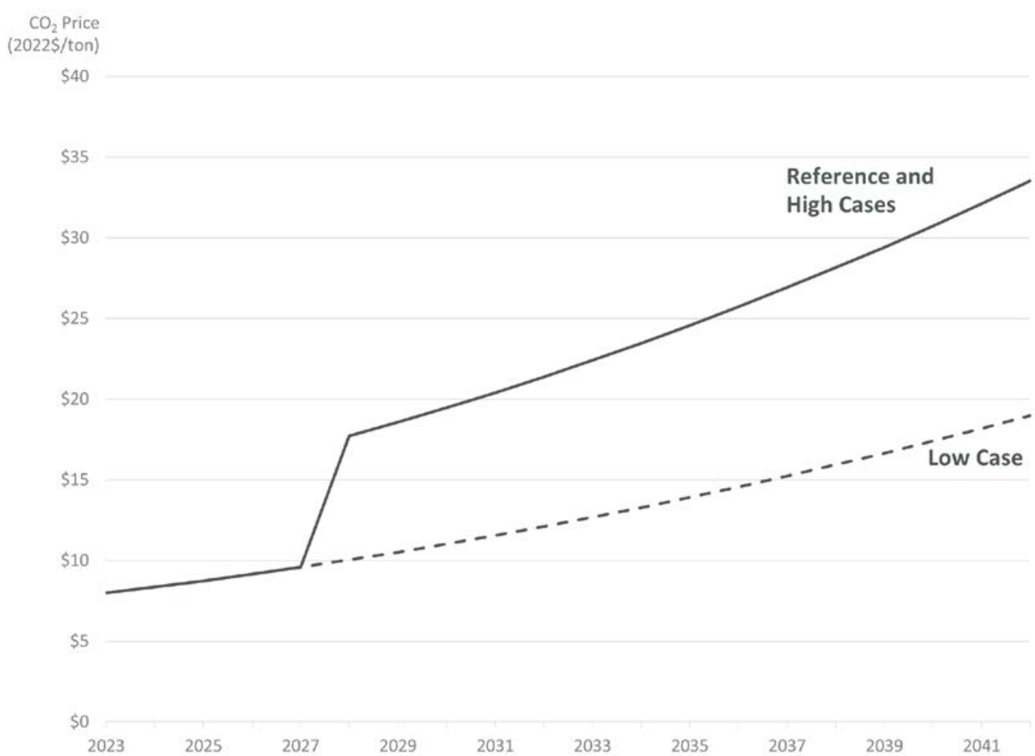

Figure 8. CO_2 Price Outlook

D. Massachusetts CO_2 Emissions Cap

In 2017, Massachusetts' Department of Energy Resources (DOER) and Department of Environmental Protection (DEP) published a rule, 310 CMR 7.74: *Reducing CO2 Emissions from Electricity Generating Facilities,* placing a declining annual cap on total CO_2 emissions from large fossil fuel-fired power plants located in Massachusetts. The regulation is part of the Commonwealth's approach to meeting the emission reduction requirements of the Global Warming Solutions Act (GWSA).

Figure 9 below shows the aggregate limits on existing and new large fossil fuel-fired generating facilities located in Massachusetts. Emission allowances are tradeable among facilities, allowing for emissions from individual plants to exceed their starting allowance.

The NMM models this constraint by limiting CO_2 emissions from affected generators to the total annual limits shown. The regulation results in slightly higher LMPs as less economic resources are re-dispatched in later years of the study period to avoid exceeding limits.

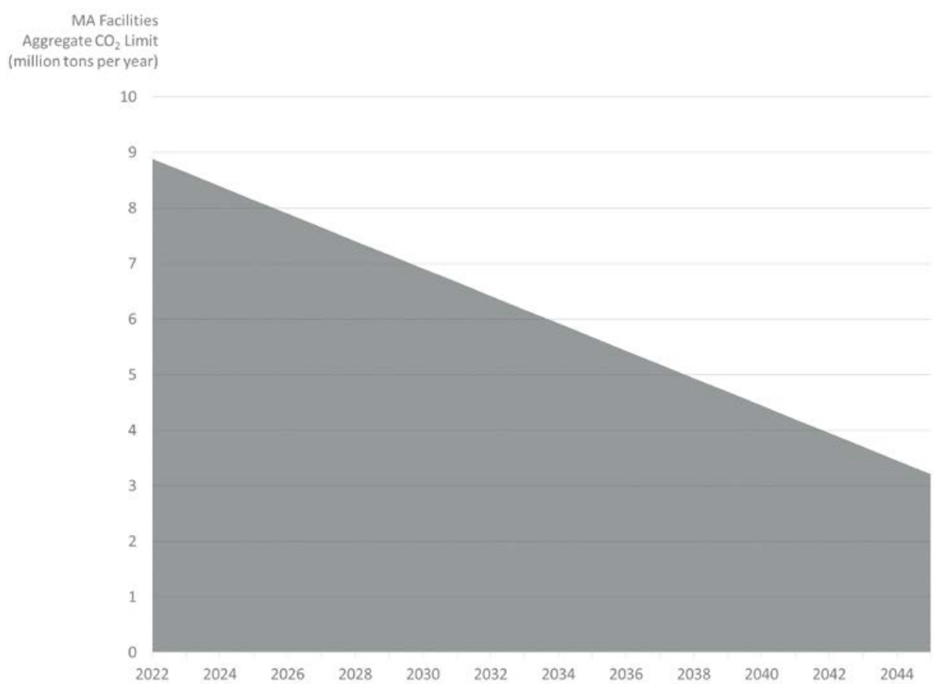

Figure 9. Massachusetts 310 CMR 7.74 CO_2 Limits (tons)

E. Retirements and Thermal Capacity Additions

Daymark's production cost modeling analysis relies on assumptions of generator retirements and additions. These resource changes impact the efficiency of marginal units and can also impact pricing, emissions, and net imports into the region, among other factors.

Our assumptions on retirements in the first few years of the study period are based on known and forecasted retirements in the ISO New England Forward Capacity Market (FCM). The primary source of the specific resource additions and retirements are the results of the ISO New England Forward Capacity Auctions (FCA) through FCA 15, which determined capacity obligations through the 2024-2025 commitment period, as well as ISO New England's report on the status of retirement requests.

Table 4 and Table 5 below show specific generation addition and retirement assumptions.

Table 4. Significant Specific Retirement Assumptions after 2020

NAME	MW	FUEL	RETIRE YEAR
Bridgeport Station 3	385	Coal	2021
Schiller 4	40	Coal	2021
Mystic 7 & Mystic Jet	575	Natural Gas	2022
Pawtucket Power	54	Natural Gas	2022
Yarmouth 1 & 2 (W. Wyman)	105	Oil	2023
South Meadow 11-14	149	Diesel	2023
Mystic 8	703	Natural Gas	2024
Mystic 9	709	Natural Gas	2024
West Springfield 3	95	Natural Gas	2024
Bridgeport Harbor 4	22	Coal	2024
South Meadow 5 & 6	91	MSW	2025

Table 5. Significant Planned New Non-Renewable Resources since 2020

NAME	MW	FUEL	COD
MMWEC Simple Cycle Gas Turbine	69	Natural Gas	2021
Cranberry Point Battery Energy Storage	150	Energy Storage Resource (ESR)	2024
Medway Grid, LLC	250	ESR	2024
Resource Cross Town	175	ESR	2024
Great Lakes Millinocket	20	ESR	2024

In addition to these resources, further retirements and resource additions are based on results of analysis conducted with Daymark's proprietary CapMarker model simulating the ISO New England FCM. The following chart shows modeled capacity supply obligation additions and retirements modeled in CapMarker.

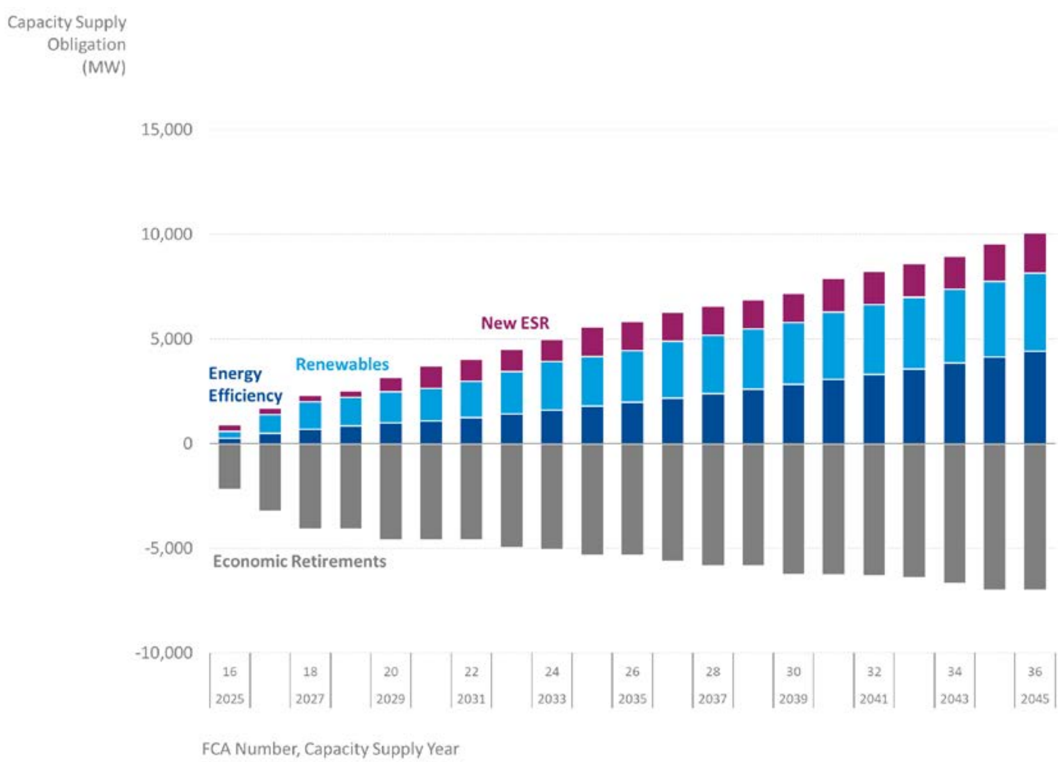

Figure 10. Cumulative Capacity Supply Obligation Additions and Retirements

F. Renewable Additions

The Daymark renewable capacity additions are determined through known renewable energy procurements, such as the New England Clean Energy RFP and individual state offshore wind RFPs. Daymark relies on publicly available reports and judgment to develop reasonable assumptions about timing and amount of contracted resources achieving commercial operation. These known capacity additions are then supplemented with additional resources, wind, and solar, to balance renewable energy certificate (REC) supply and demand based on both individual states' RPS requirements as well as stated legislative renewable capacity targets. Figure 11 summarizes the renewable buildout developed in this analysis.

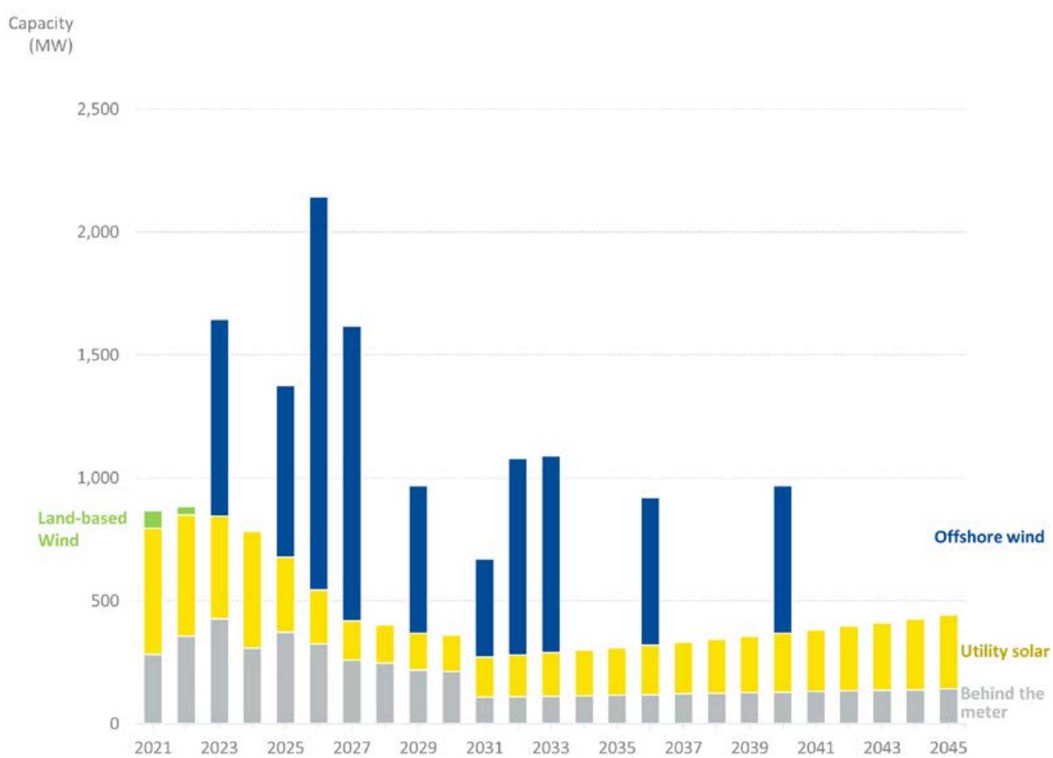

Figure 11. Renewable Buildout (Nameplate capacity additions per year)

Offshore wind assumptions

Led by Massachusetts, New England states have already contracted for 3.1 GW of new offshore wind projects interconnecting to the New England grid. Current state policies and announcements call for additional capacity to be added beyond those already contracted, including:

- Massachusetts enacted legislation in March 2021 (S.B. 9, "*An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy*") that authorizes procurement of an additional 2.4 GW of offshore wind by 2027, on top of the 1.6 GW already procured
- Connecticut passed Public Act 19-71 ("*An Act Concerning the Procurement of Energy Derived from Offshore Wind*") setting a target of 2,000 MW offshore wind procurements by 2030
- Rhode Island has announced intentions to issue an RFP for about 600 MW of additional offshore wind sometime in 2021

We assume that these targets are achieved but with some delay. The table below shows our assumed offshore wind capacity additions, including both projects with awarded contracts and generic additions in later years to meet procurement targets.[5]

[5] On December 17, 2021, Massachusetts announced awards to projects totaling 1600MW in the 83C III RFP process. Our model has not yet been updated to include the specific winning projects. A generic project of 1200MW is represented currently.

Table 6. New Offshore Wind Buildout Assumed in Case

PROJECT	PROCUREMENT / POLICY TARGET	MW	POI	COD
Vineyard Wind	MA 83C-I	800	SEMA	2023
Revolution Wind	RI 2018 RFP CT Clean Energy CT Zero CO_2	704	RI	2025
Mayflower Wind	MA 83C-II	800	SEMA	2026
Park City Wind	CT Offshore Wind RFP	800	SEMA	2026
Generic Project 1	MA 83C-III	1200	SEMA	2027
Generic Project 2	RI 600MW RFP	600	SEMA	2029
Generic Project 3	CT 2 GW target	400	CT	2031
Generic Project 4	MA 4GW target	800	BOST	2032
Generic Project 5	MA 4GW target	800	BOST	2033
Generic Project 6	MA expanded GWSA target	200	SEMA	2036
Generic Project 7	CT 2 GW target	400	SEMA	2036
Generic Project 8	MA expanded GWSA target	400	SEMA	2040
Generic Project 8	CT 2 GW target	200	CT	2040

Distributed solar assumptions

The NMM includes a forecast of distributed, behind-the-meter solar. Our forecast is based on the ISO New England distributed solar forecast, conducted as part of the annual load forecast and CELT report process.

The figure below summarizes our assumptions of distributed solar buildout by state.

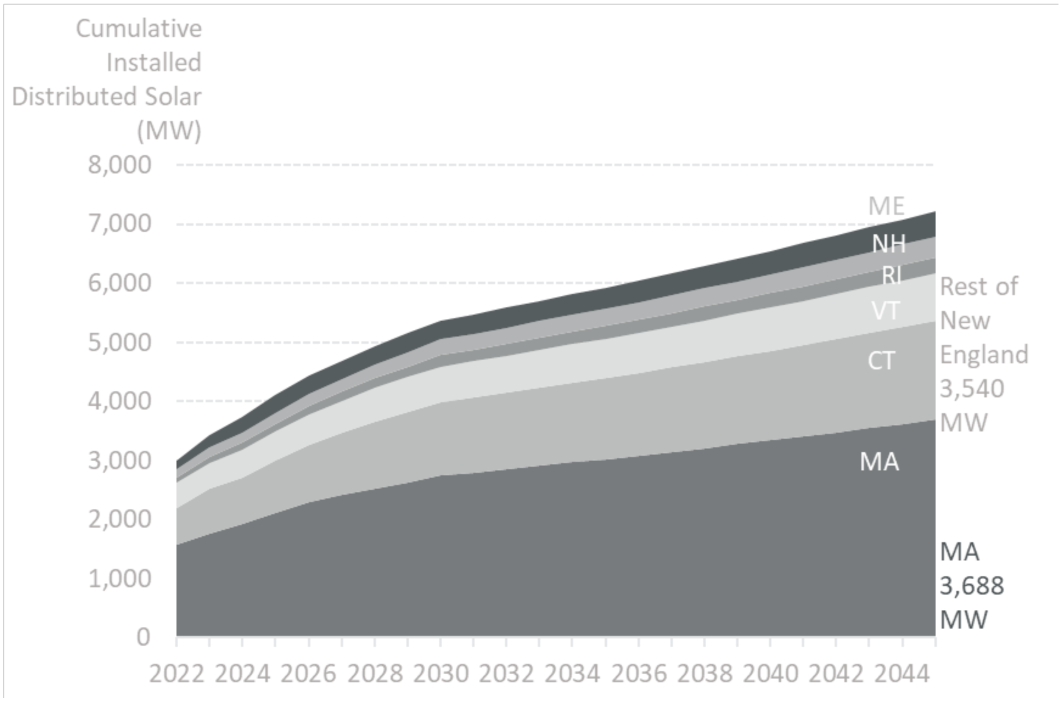

Figure 12. Distributed Solar Buildout (Cumulative MW)

G. Energy Storage Resource Additions

The NMM includes significant additions of energy storage resources (ESR) based on three drivers:

- Specific additions, based on the 595 MW from four projects clearing capacity obligations in FCA 15
- Generic additions driven by economic entry in our CapMarker FCM capacity market modeling
- Generic additions in Massachusetts driven by Massachusetts Clean Peak Standard compliance

Figure 13 below shows new capacity additions by zone.

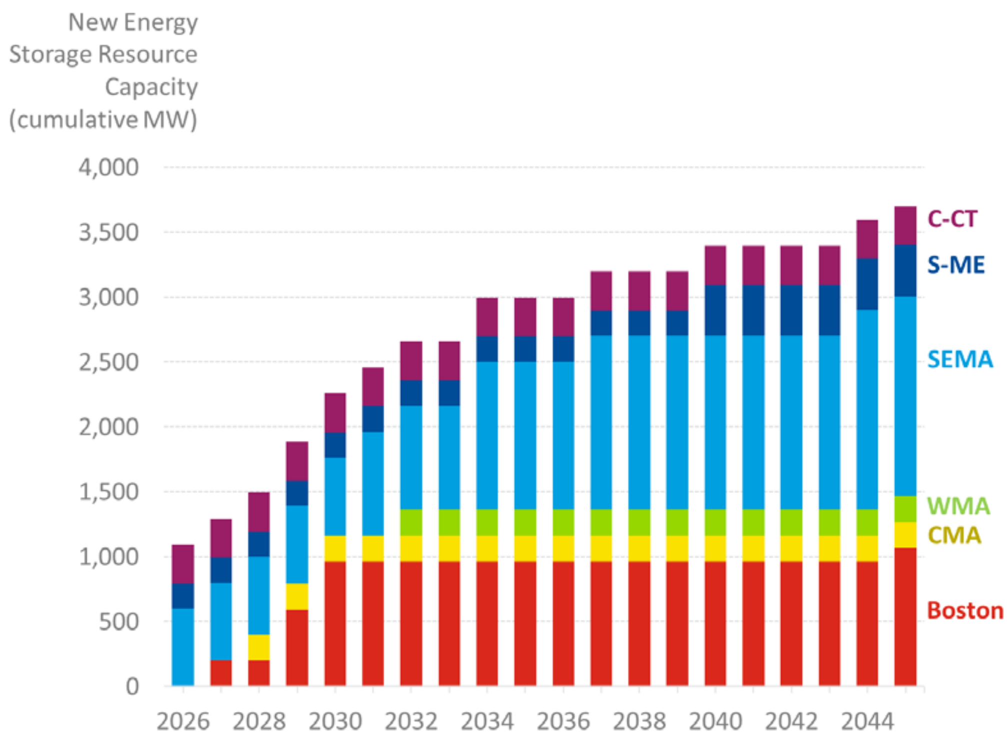

Figure 13. New Energy Storage Resource Buildout (Cumulative MW)

H. Renewable Dispatch Pricing

Resource dispatch prices in the model are typically set by the variable costs of a generator – fuel, variable O&M, emissions, etc. Intermittent renewable resources, however, typically have incentive payments (e.g., RECs) associated with their output that makes these resources price-takers even if LMPs go negative. This is modeled in NMM by assigning a negative bid adder, meaning the resource is willing to pay to avoid being dispatched down (curtailed). The negative bid adders by resource are shown in the table below, based on the "REC-Inspired Threshold Prices" used in ISO New England's *2021 Economic Study: Future Grid Reliability Study Phase 1*.[6]

[6] ISO New England PAC Presentation (May 19, 2021). 2021 Economic Study: Future Grid Reliability Study Phase 1; Overview of Assumptions – Part 2, Slide 13. Available at: https://www.iso-ne.com/static-assets/documents/2021/05/a3_2021_economic_study_future_grid_reliability_study_phase_1_overview_of_assumptions_part_2.pdf

Table 7. Dispatch Threshold Prices for Intermittent Renewable Resources

RESOURCE	THRESHOLD PRICE (2022$/MWH)
Land-based Wind	-$20
Offshore Wind	-$25
Grid PV	-$32

I. External Interchange

Import and export flows over tie lines with neighboring control areas are modeled based on historical baseline flows, with threshold prices at which baseline flows can deviate from historical averages.

Baseline flow is based on typical weekday and weekend hourly shapes from 2018 to 2020 for each month and external interface.

Threshold prices to curtail or increase baseline flows (up to interface limits – see Table 2) are shown in the table below, based on the "REC-Inspired Threshold Prices" used in ISO New England's *2021 Economic Study: Future Grid Reliability Study Phase 1*.[7] Canadian interfaces are assumed to be import only. The new HQ NECEC line, in cases when it is assumed to come online, is assumed to have baseline flow of 1,090 MW in all hours beginning in the year of COD.

[7] ISO New England PAC Presentation (May 19, 2021). 2021 Economic Study: Future Grid Reliability Study Phase 1; Overview of Assumptions – Part 2, Slide 13. Available at: https://www.iso-ne.com/static-assets/documents/2021/05/a3_2021_economic_study_future_grid_reliability_study_phase_1_overview_of_assumptions_part_2.pdf

Table 8. Threshold Prices for Deviation from Baseline Import/Export Flows (2022$/MWh)

EXTERNAL INTERFACE	CURTAIL IMPORT	INCREASE IMPORTS	CURTAIL EXPORT	INCREASE EXPORTS
HQ – Phase II	5	200	n/a	n/a
HQ – Highgate	5	200	n/a	n/a
New Brunswick	10	200	n/a	n/a
NYISO AC Ties (excluding Northport)	13	200	200	-28
NYISO Northport	13	200	200	-28
NYISO Cross Sound Cable	13	200	200	-28
HQ – NECEC (new)	2	200	n/a	n/a

IV. RESULTS

The figures below show the forecasted Vermont zonal prices for the Reference, High and Low Cases on an annual and monthly basis. Levelized prices assume a discount rate of 6.0% for the 20-year study period 2023 – 2042.

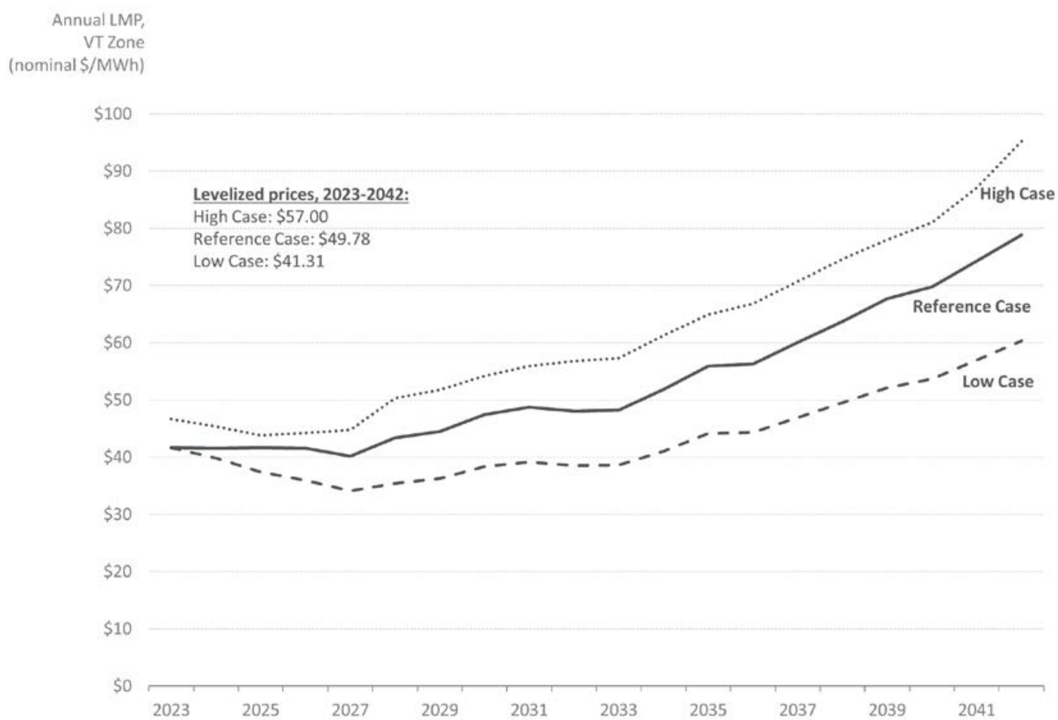

Figure 14. Annual Vermont Zonal Price Forecast

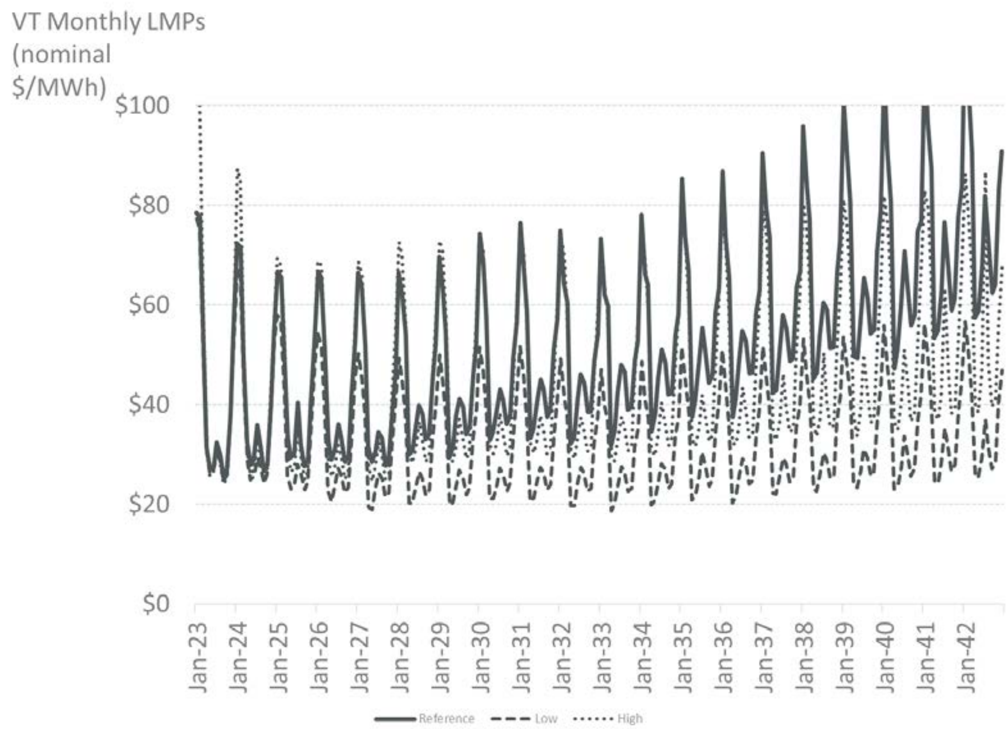

Figure 15. Monthly Vermont Zonal Price Forecast