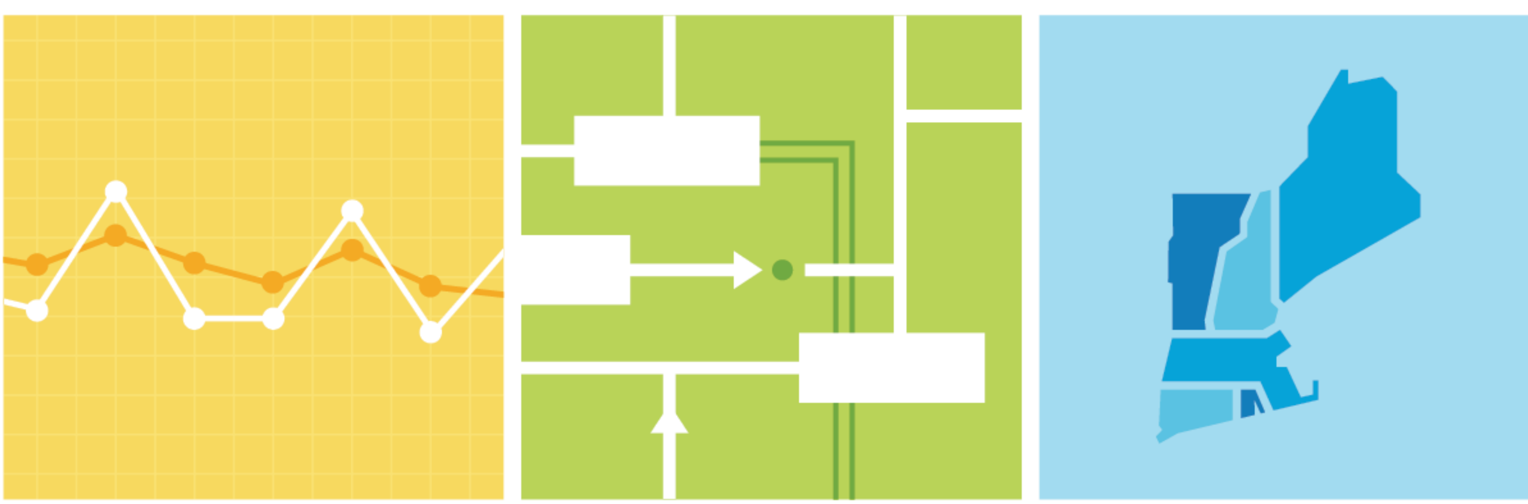
2023 Annual Markets Report

Internal Market Monitor

MAY 24, 2024

ISO-NE PUBLIC



Document Revision History		
Date	**Version**	**Remarks**

Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2023 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2023. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Appendix A, Section III.A.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[2]

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2023. The executive summary gives an overview of the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Sections 1 through Section 9 include more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report.

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[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation", available at http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

[2] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.[3]

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

Underlying oil and coal pricing data are furnished by Argus Media.

[3] See https://www.iso-ne.com/about/corporate-governance/financial-performance

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Executive Summary

The 2023 Annual Markets Report by the Internal Market Monitor (IMM) at ISO New England (ISO) addresses the development, operation, and performance of the wholesale electricity markets. The report presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electricity in the day-ahead and in real-time markets, the participants in the forward and real-time markets buy and sell operating reserve products, regulation service, financial transmission rights, and capacity. These markets are designed to ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

To provide readers with additional background on our markets, last year, we published a supporting document, "An Overview of New England's Wholesale Electricity Markets: A Market Primer".[4] We expect that this document will be a useful in helping readers understand the fundamental concepts and mechanics of our markets.

In this executive summary, we provide an overview and assessment of key market trends, performance, and issues. We follow this with a consolidated list of recommended enhancements to the market design and rules from this and prior IMM reports.

The capacity, energy, and ancillary service markets performed well and, with the exception of the Forward Reserve Market (FRM), exhibited competitive outcomes in 2023. Day-ahead and real-time energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix. In 2023, there were very few periods of tight system conditions and scarcity pricing that impacted overall energy market outcomes.

Energy prices in 2023 returned to typical levels after record highs in 2022; the annual average day-ahead price of $37/MWh was down by almost 60% from 2022. Energy prices continued to follow the market price of natural gas, which at about $3/MMBtu was nearly 70% lower than the average 2022 price. Lower natural gas prices reflected high national inventory levels, a lack of sustained cold weather in New England, and the settling of international energy markets following the Russian invasion of Ukraine.

The growing impact of renewable energy sources on New England's markets is manifesting in a number of ways. In particular, residential solar generation is reducing load levels and shifting peak load to later in the day. In 2023, New England's average wholesale load was at its lowest level in at least twenty-four years. In addition, renewable energy sources like wind and solar, which have low marginal costs, alongside existing non-price-setting supply, can lead to instances of low or negative energy prices. However, our analysis indicates that energy price formation remains resilient, with prices typically reflecting marginal input costs.

High-level market statistics for the five-year period covered in this report are presented below.

[4] See *An Overview of New England's Wholesale Electricity Markets: A Market Primer* (June 2023), available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf. This document will be updated periodically, particularly to reflect changes to market design such as the upcoming Day-Ahead Ancillary Services Initiative.

At a Glance: High-level Market Statistics

Demand (MW)	2019	2020	2021	2022	2023	% Change '22 to '23	Sparkline
Load (avg. hourly)	13,611	13,305	13,560	13,576	13,096	-4%	
Weather-normalized load (avg. hourly)[a]	13,558	13,242	13,419	13,514	13,132	-3%	
Peak load (MW)	24,361	25,121	25,801	24,780	24,016	-3%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	25.41	16.34	36.07	72.41	23.68	-67%	
Coal	40.54	37.83	67.95	144.99	69.13	-52%	
No.6 Oil	130.90	89.43	138.30	221.15	164.91	-25%	
Diesel	173.54	112.06	184.69	332.15	253.44	-24%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	31.22	23.31	45.92	85.56	36.82	-57%	
Real-time (simple avg.)	30.67	23.37	44.84	84.92	35.70	-58%	
Day-ahead (load-weighted avg.)	32.82	24.57	48.30	91.36	39.19	-57%	
Real-time (load-weighted avg.)	32.32	24.79	47.34	91.13	38.25	-58%	
Estimated Wholesale Costs ($ billions)							
Energy	4.1	3.0	6.1	11.7	4.8	-59%	
Capacity[c]	3.4	2.7	2.3	2.0	1.8	-13%	
Uplift (NCPC)	0.03	0.03	0.04	0.05	0.03	-35%	
Ancillary Services[d]	0.1	0.1	0.1	0.1	0.2	33%	
Regional Network Load Costs	2.2	2.4	2.7	2.8	2.7	-4%	
Total Wholesale Costs	**9.8**	**8.1**	**11.2**	**16.7**	**9.5**	**-43%**	
Supply Mix [e]							
Natural Gas	39%	42%	45%	45%	48%	3%	
Nuclear	25%	22%	22%	23%	20%	-3%	
Imports	19%	20%	16%	14%	13%	-1%	
Hydro	7%	7%	6%	6%	8%	2%	
Other[f]	5%	5%	5%	4%	4%	0%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	1%	2%	2%	3%	3%	0.3%	
Coal	0%	0%	0%	0%	0.2%	-0.11%	
Oil	0%	0%	0%	2%	0.3%	-1.25%	
Battery Storage	0%	0%	0%	0%	0.2%	0.15%	

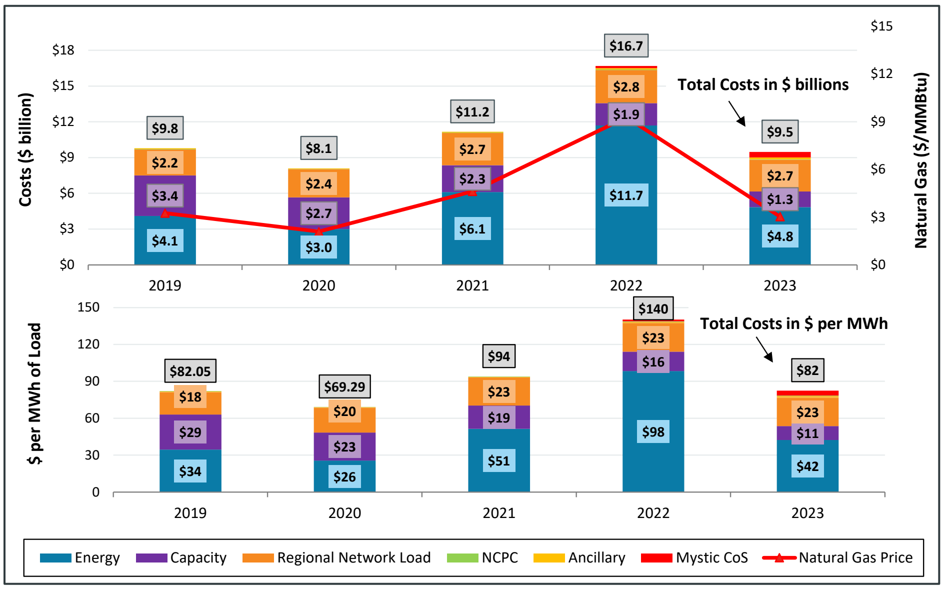
[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Capacity costs in 2022 and 2023 include Mystic cost-of-service costs
[d] Ancillary Services include inventory energy program costs incurred in December, 2023
[e] Provides a breakdown of total supply, which includes net imports; Note that section 1.2 provides a breakdown of native supply only
[f] The "Other" fuel category includes landfill gas, methane, wood, refuse and steam
denotes change is within a band of +/- 1%

Sparkline: Green = High Point, Red - Low Points

Lower energy costs, comprising half of total costs, drove an overall decrease in wholesale costs due to lower natural gas prices

The total wholesale cost of electricity in 2023 was $9.5 billion, the equivalent of $82 per MWh of load served.[5] This was a 43% drop compared to 2022 costs (of $16.7 billion). The decrease was largely due to lower energy costs driven by natural gas prices. Natural gas prices fell by 67% between 2022 ($9.28/MMBtu) and 2023 ($3.04/MMBtu). Also, with the exception of ancillary services costs (up by $0.01 billion), every other component of the wholesale cost of electricity decreased in 2023.

Significantly Lower Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs fell to $4.8 billion, marking a significant 59% decline from the $11.7 billion recorded in 2022, a year characterized by soaring natural gas prices, reaching their highest levels since 2008. However, the downward impact of lower natural gas prices was somewhat offset by shifts in the supply mix that resulted in costlier generator commitments. Notably, nuclear generation saw an average decrease of 480 MW per hour, mainly due to planned refueling outages.

Uplift costs, or Net Commitment Period Compensation (NCPC), amounted to $34 million ($0.30/MWh), down 35% from $53 million in 2022. The majority (93%) of NCPC payments covered the operating costs of resources committed in economic merit order to meet system load and reserve requirements ("economic" NCPC), and decreased by $18.3 million, consistent with the drop in energy market prices. Payments for reliability services (voltage or local reserve support) were very low ($0.7 million), following a decline in recent years in reliability commitments due to transmission network investments. NCPC accounted for a slightly higher percentage (0.7%) of overall energy market costs in 2023 compared to 2022's 0.5%, due to increased payments to fast-start out-of-merit resources towards the end of 2023 when a large amount of flexible generation capacity was out of service.

[5] The wholesale cost of electricity comprises energy, uplift, ancillary services and transmission costs.

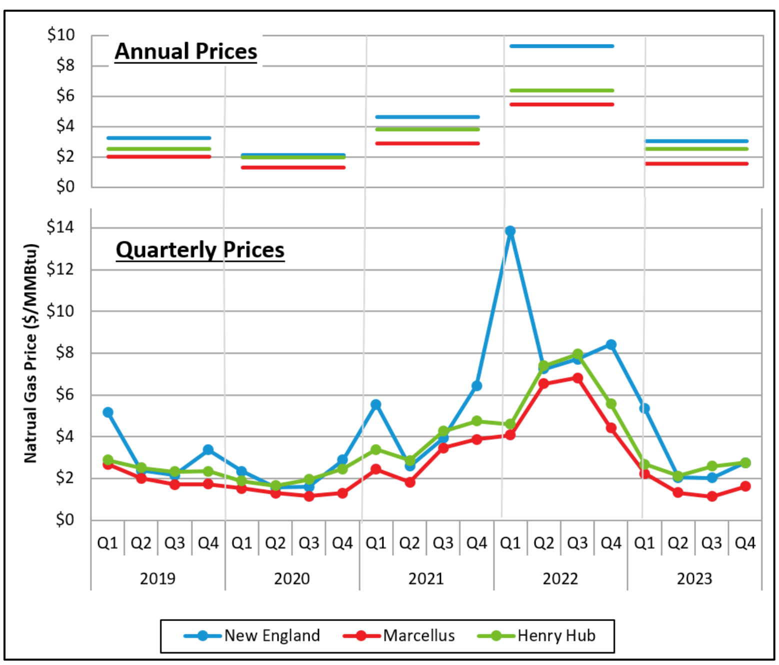
Payments pursuant to the Cost of Service (CoS) agreement with the Mystic 8 and 9 combined cycle generators totaled $460 million. These payments are a form of uplift to compensate resources outside of the *capacity market* for providing fuel security reliability services. These costs were more than ten times higher than energy uplift payments, at $460 million, or $4/MWh of load and pose challenges for payers of uplift as they can be difficult to predict and hedge.

Capacity costs, which comprised just 14% of total wholesale costs, continued to decline as the market maintains surplus capacity over the system's capacity requirement. Costs totaled $1.3 billion and were down by 30% (or by $0.56 billion) on 2022. The costs were a function of lower combined clearing prices in the thirteenth and fourteenth Forward Capacity Auctions (FCAs 13 and 14).

Falling natural gas prices brought wholesale energy prices in New England back to pre-2022 levels, while CO_2 emissions prices were a larger component of fossil fuel generation costs

In 2023, the cost of natural gas dropped to its lowest point since 2020, primarily because of mild weather and ample U.S. natural gas supply. Nationally, temperatures during the winter quarter (Q1) of 2023 were milder compared to 2022, leading to decreased demand for heating and consequently lower natural gas prices. The supply of natural gas expanded in 2023 as the United States achieved record-high levels of production, and natural gas reserves surpassed five-year averages. Lower natural gas prices (down 67%) were the single most significant factor behind lower energy prices (down 57%) as gas-fired generators made up almost half (48%) of total supply and set the real-time price 84% of the time.

Lower Spread between New England and Henry Hub, Marcellus Natural Gas Prices

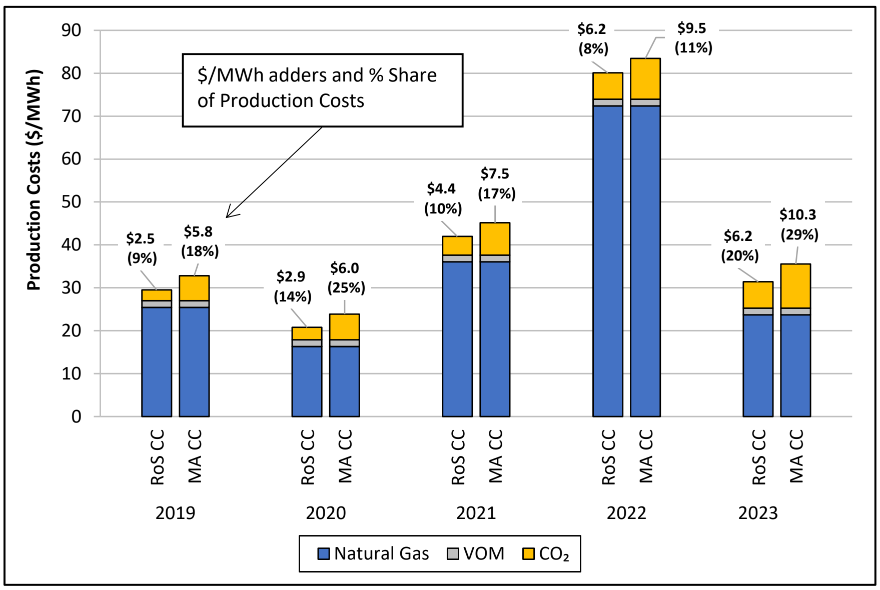


The decrease in New England natural gas prices was in line with year-over-year decreases at national supply basins, Henry Hub and Marcellus. During constrained winter periods, the New

England natural gas price can diverge from supply basin prices due to high residential heating demand utilizing most of the gas network capacity, as was very apparent in Q1 2022 prices. Spreads during the winter periods in 2023 were much lower due to mild winter weather in New England and a lack of sustained cold spells.

New England has two carbon-reducing cap-and-trade programs that impact production costs and electricity prices: (1) The Regional Greenhouse Gas Initiative (RGGI), covering generators in all New England states, and (2) The Electricity Generator Emissions Limits (referred to as the MA EGEL program below) under the Global Warming Solutions Act (GWSA), covering only Massachusetts generators. For both programs, CO_2 emissions costs increased slightly in 2023 relative to prior years, but with lower fuel costs, comprised a larger share of generation production costs; from 6% for oil generation to 20%-30% for natural gas generation. CO_2 emissions costs were therefore a notable driver of energy prices. We estimate that CO_2 contributed about $6/MWh to the average annual energy price on a load-weighted basis (or 15% of $39/MWh) and about $690 million to total energy costs (or 14% of $4.8 billion).[6]

Breakdown of Estimated Combined Cycle (CC) Production Costs by Component[7]



Net interchange with neighboring control areas continued to decrease

In 2023, average net interchange, or net imports, was 1,724 MW per hour, meeting 13% wholesale demand. This was the lowest level of net interchange since 2012, and down by 10%

[6] The net costs of the CO_2 emission programs are significantly lower (than the estimated wholesale energy cost impact) as the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs, clean and renewable energy. For instance, the majority of auction proceeds from RGGI are invested by the New England States in energy efficiency programs, which have has a significant impact on reducing wholesale demand and wholesale energy costs (see Section 1.5). Similarly, the majority of proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions.[6]

[7] RoS CC = Rest of System Combined Cycle generators to which RGGI costs apply. MA CC = Massachusetts Combined Cycle generators to which both RGGI and MA GWSA costs apply. The estimated costs are based on an average heat rate of 7.8 MMBtu/MWh.

(or 190 MW per hour) on 2022. The decline in average net interchange was due to reduced imports from the Canadian interfaces, particularly Phase II.

Across the three Canadian interfaces, the average net interchange decreased by 355 MW per hour compared to 2022, dropping from 1,781 MW to 1,426 MW, and were at the lowest levels since 2011. This reduction was influenced by lower reservoir levels in Québec, which resulted in decreased excess hydroelectric generation and lower availability of imports over the Phase II interface into New England.[8]

Capacity backed by imports continued to clear at low levels in the past two Forward Capacity Auctions (FCAs 17 and 18) relative to historical levels, an indication of potentially higher capacity values in neighboring jurisdictions. From FCA 11-16 (2020 to 2026), the volume of cleared import capacity fluctuated between 1,000 MW to 1,500 MW. In the past two auctions, cleared import capacity decreased significantly, with only 465 MW clearing in FCA 18 (for delivery in 2027/28).

The trend of decreasing load driven by EE and BTM continues

Average and peak load levels were the lowest in years, down by 4% and 3%, respectively, from 2022 levels, consistent with mild summer and winter weather. Net Energy for Load (NEL) averaged 13,096 MW per hour in 2023 and peak load 24,016 MW. On a weather-adjusted basis, load declined by 3%, which reflects the adoption of behind-the-meter (BTM) solar generation.[9]

BTM solar generation reduced weather-normalized hourly load by 489 MW (by 3%) which was a 7% increase (34 MW) compared to 2022; it is expected to continue this upward trend in future years. In 2023, energy efficiency (EE) reduced average hourly load by an estimated 2,269 MW (by 14%), which was an 11% decrease (268 MW) compared to 2022. This is in line with the ISO's expectation that EE will decline over time due to rising costs of eligible EE measures and the associated baselines used to calculate claimable savings.

The changing generation mix brings both challenges and opportunities

The New England States are advancing their decarbonization goals through substantial investments in the power sector. This includes a focus on enhancing energy efficiency measures (EE), bolstering storage capacities, and expanding renewable energy sources in both the wholesale markets and at the retail level such as solar BTM generation.

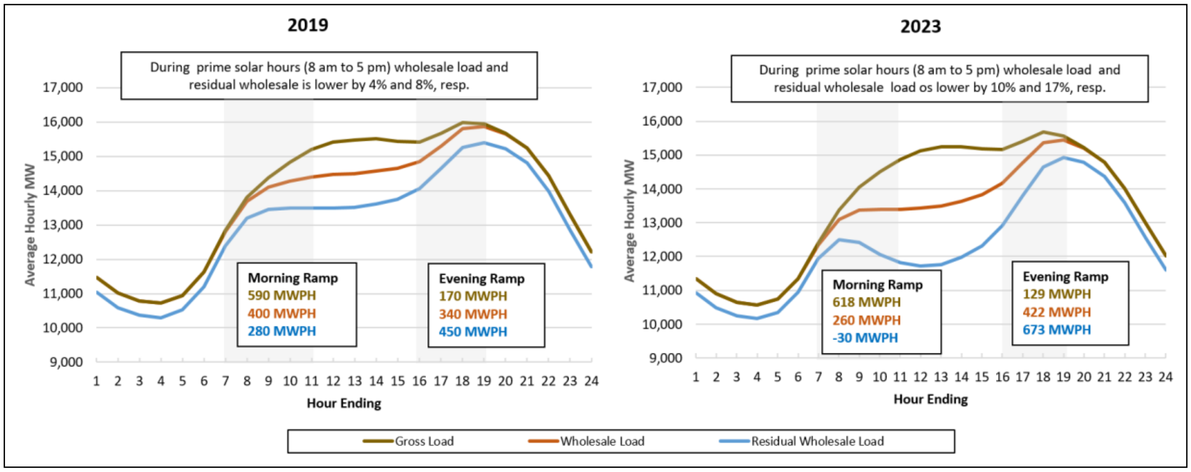
In particular, BTM solar generation has experienced significant growth, with projections indicating a doubling of capacity over the next decade. Solar generation in the middle of the day

[8] For more information, see Hydro-Québec's *Quarterly Bulletin: Third Quarter* report (Q3 2023), available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2023-3.pdf . See for example the following commentary on page 4: "The results for 2023 are set against a backdrop of low runoff as a result of which Hydro-Québec has been reducing its exports to short-term markets. In fact, scant snow cover in late winter 2022-2023, lower-than-usual spring runoff and modest summer precipitation in northern Québec have reduced natural water inflows to the company's large reservoirs. In order to ensure optimum management of resources, the company has therefore limited its electricity sales on external markets, resulting in a significant drop in related revenues. However, this situation had no impact on Québec's energy supply or its long-term commitments with neighboring markets."

[9] While weather-normalized load increased slightly in 2021 and 2022, the trend of declining weather-normalized load continued in 2023.

has led to the emergence of the wholesale demand "duck curve," which has been increasingly pronounced over the past five years.[10] With the expected surge in solar capacity, this trend is likely to pose challenges and opportunities for market participants, market designers and system operators in the coming years.

Solar and Wind Impacts on Average Load Profiles, 2019 vs. 2023[11]



While the growth in solar generation has altered the profile of wholesale demand and energy prices, we have not observed excess supply issues during the lowest afternoon load hours or flexibility issues in meeting steeper evening ramps. Moreover, the dip in energy prices during early afternoon hours presents an opportunity for energy storage resources to charge, thereby preparing for higher prices during evening load ramps, consequently smoothing out wholesale load and price fluctuations.

Low levels of structural market power and mitigations in the energy market, but not in the Forward Reserve Auction

Market concentration among the top four firms controlling real-time energy market supply remained consistent with prior years, at 41% in 2023. The four largest load-serving entities accounted for 52% of total real-time load. While instances of structural market power were more prevalent in 2023, due to slightly lower operating reserve margins caused by generator outages in Q4, margins remained relatively high on average compared to requirements. Therefore, the change in structural competitiveness is not due to factors that are expected to persist.

There was a higher frequency of pivotal suppliers in 2023 compared to prior years, with the average Residual Supply Index (RSI) in the real-time energy market dropping from 104.6 in 2022 to 103.5 in 2023, dipping below 100 in 37.3% of intervals. Despite this, mitigation of

[10] The duck curve — named after its resemblance to a duck — illustrates the daily fluctuation in electricity demand, characterized by a sharp decrease during midday due to solar generation and a steep increase in the evening as solar production diminishes and demand rises.

[11] Gross Load includes load served by estimated BTM generation, while Wholesale Load is Net Energy for Load (NEL) - a definition generally used to quantify wholesale market demand. “Residual Wholesale Load” is wholesale load net of output from wind and wholesale-participating solar generation.

supply offers continued to be infrequent at just 460 asset hours of mitigation, compared to 1.4 million asset hours (or 0.03%) subject to potential mitigation.

Our economic withholding analyses indicate that the impact of supply offer markups on prices in both real-time and day-ahead markets remained close to zero or negative. Furthermore, withheld economic capacity in 2023 was relatively low, below approximately 2%, aligning with levels observed in previous years.

In recent Forward Reserve Market (FRM) auctions, evidence of structural market power has been prominent, particularly during summer procurement periods. Over the past five summers, our measures of structural competitiveness have produced results below the level indicative of a competitive process. Similarly, we observed structurally uncompetitive levels in the most recent winter auction. This lack of competition at the structural level and high clearing prices prompted us to recommend a review and update of the forward reserve offer cap price.[12] The ISO acted on the recommendation with proposed rule changes, which were recently approved by FERC.[13]

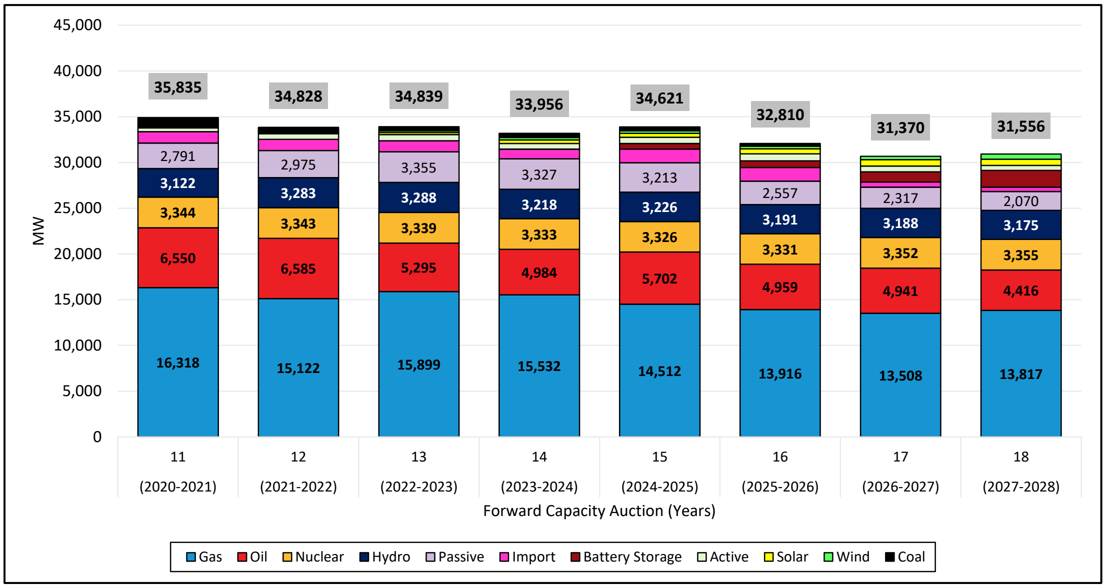
Capacity costs rise and older fossil-fueled generators continue to make way for renewable resources

Renewables, or sponsored policy, generation have dominated new additions in recent auctions, comprising 67% of all new additions since FCA 15, while major retirements included nuclear, oil-, and gas-fired resources. This trend continued in FCA 18; 1,140 MW of new resources cleared, with battery storage projects (740 MW) and wind projects (185 MW) representing the largest new entrant types. Oil generation and import resources made up the largest share of uncleared (exiting) capacity. Of the 2,400 MW of existing capacity exiting the capacity market, over 800 MW retired permanently while the remaining de-listed for one year.

[12] The IMM's recommendation related to the forward reserve offer cap can be found in its *Spring 2023 Quarterly Markets Report* (August 1, 2023), p 43, available at https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf

[13] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap*, ER24-1245-000 (April 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf

Trends in the Forward Capacity Market Resource Mix



The capacity market continued to maintain a surplus above the Net Installed Capacity Requirement (NICR); in FCA 18 the market cleared 1 GW over NICR of 30.5 GW. The FCA 18 clearing price of $3.58/kW-month was 38% higher than FCA 17 and will result in a comparable increase in costs, totaling $1.3 billion. The Net CONE value for FCA 18 was $9.08/kW-month, up 23% from FCA 17, and was the most significant change to the auction input parameters that resulted in a shift of the demand curve to the right. This increase reflected the impact of inflationary indices applied to key inputs into Net CONE.

Based on our pre-auction review of de-list bids, excess capacity before and during the auction, and the liquidity of dynamic de-list bids, it is our opinion that auction outcomes were the result of a competitive process.

In the context of anticipated capacity margins out to 2028 and expected changes to the resource mix thereafter, it is an opportune time to develop a Prompt and Seasonal Capacity Market

We support developing a prompt and seasonal capacity market construct as a more cost-effective and efficient approach to procuring and pricing capacity than the current forward market framework.[14] A prompt market can address inaccuracies caused by the uncertainty of auction inputs years ahead of delivery, addressing issues in peak load forecasting, supply side deliverability, and capacity value accreditation. As the grid evolves, the benefits of such a market will become more apparent, aligning better with disparate and uncertain development timelines, an aging generation fleet, and seasonal reliability risks.

[14] See *IMM Thoughts on a Prompt and Seasonal Capacity Market* (January 31, 2024), at https://www.iso-ne.com/static-assets/documents/100009/a02b_mc_2024_03_12_13_imm_perspective_alternative_fcm_commitment_horizons.pdf See, also *Comments of the Internal Market Monitor on Further Delaying the Nineteenth Forward Capacity Auction* (April 22, 2024), available at *https://www.iso-ne.com/static-assets/documents/100010/imm_comments_on_fca_19_delay_request.pdf*

The forward market, running years in advance, provided price signals for investment, particularly for combined cycle resources with long development timelines. However, retaining this forward price value through an auction construct entails significant market costs due to the uncertain nature of supply and demand side auction inputs and their impact on marginal clearing prices. Notably, the forward market has faced challenges due to delayed or terminated projects and uncertainty of inputs into the determination of the Net Installed Capacity Requirement. A prompt market could address these issues by aligning more closely with resource timelines and system needs. Supply offers in a prompt and seasonal auction are also likely to reflect avoidable costs more accurately, including winter fuel costs, enhancing price formation while maintaining revenue sufficiency for resources.

In this report, we add two new recommendations regarding future market enhancements

Reserve accounting for transmission-constrained resources: The IMM has identified potential enhancements to the accounting of reserves for resources in export-constrained areas. There are times when the market clearing assumes reserve capability for capacity that is not deliverable.

Specifically, we have identified instances where reserve prices could have been higher if the reserve down flag had been consistently applied to transmission-constrained resources. For instance, in 2021, applying the reserve down flag could have increased reserve clearing prices for Ten-Minute Spinning Reserve (TMSR) in 192 hours, illustrating the potential impact on market dynamics. While the overall market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints. We therefore recommend that the ISO establish an automated process for the application of the reserve down flag, to improve reserve accounting and associated market outcomes.

Publication of Resource Retirements that have occurred prior to their retirement date in the FCM: The current retirement process is linked to the capacity market qualification process in which resources elect priced or unconditional retirements for a given FCA. Retirement elections are published in advance of the FCA so that the market has information to inform new entry decisions.

However, the actual timing of retirements does not always align with the capacity commitment period in which the resource retires, and we have observed notable retirements occurring more than one year earlier. These retirements remain outside of the current publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants, and we therefore recommend that ISO publish such retirements to the marketplace.

IMM Market Enhancement Recommendations

One of the IMM's key functions is to recommend rule changes to enhance the performance of the markets. In practice, we communicate our recommendations through our reports, particularly our quarterly markets performance reports, and through comments filed with FERC on proposed rules changes.

The table below summarizes the IMM's recommended market enhancements, first showing issues with an "open" status, followed by recently closed issues. Recommendations included in this report for the first time are identified as "*NEW*". A hyperlink is provided to the document in which the recommendation was first put forward, along with the IMM's priority ranking of each recommendation.

The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well as the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, low priority recommendations are not intended to indicate low importance, but rather issues, which may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

ID	Recommendation	Report Source	Status	Priority Ranking
2024-1	***NEW* Publish generation retirements that have occurred either prior to the effective retirement date in the FCM or outside of the FCM process.** Retirement timings do not always align with capacity commitment periods and remain outside of the publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants.	2023 AMR	New Recommendation.	Medium
2024-2	***NEW* Establish an automated process to ensure transmission-constrained resources are not designated for reserves.** Resources in New England are not eligible to provide operating reserves if constrained by transmission limitations. In practice, this is achieved through a manual process performed by system operators. When a transmission constraint binds, operators are tasked with applying a 'reserve down' flag to resources limited by that constraint. ISO dispatch software will not designate reserves on units that have the reserve down flag applied. This reflects the fact that, due to the transmission constraint, the reserves that would normally be counted on such resources are not deliverable to the system as energy. While market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints.	2023 AMR	New Recommendation.	Low

ID	Recommendation	Report Source	Status	Priority Ranking
2023-1	***Review energy mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area.*** Market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generators supply offers. The IMM has identified a number of potential rule improvements to better serve the mitigation function. 1. Review of the current energy mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. 2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market. 3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas. 4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the "conduct test"). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels.	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium
2023-2	***Review reserve pricing mechanics under fast-start pricing.*** Under current fast-start pricing rules, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium

ID	Recommendation	Report Source	Status	Priority Ranking
2023-3	***Update the Forward Reserve Market Auction Offer Cap.*** To limit the potential exercise of market power, the forward reserve auctions utilize a price cap (i.e., an upper bound on reasonably competitive supply offer prices). Based on our review of inputs into the price cap formulation, we believe it would be prudent to update the cap based on prevailing market and system conditions. Our review suggests that the current price cap substantially overstates a reasonable upper bound on competitive forward reserve supply offers. Further, given the frequency of structurally-uncompetitive forward reserve auctions and elevated offer pricing in the summer 2023 auction, we are concerned that the publication of auction offer data may provide strategic information to participants in the auctions. We recommend that the ISO cease the publication of auction offer data or delay publication until several auction cycles have passed.	2023 Spring QMR (Aug 2023)	The ISO /NEPOOL proposal was approved by FERC.	High
2022-1	***Incentive rebuttal component of proposed Buyer-side Mitigation Rules.*** The ISO's proposed buyer-side mitigation rules will allow a Project Sponsor to demonstrate a lack of incentive through a Net Benefits Test to avoid mitigation of a below-cost supply offer from certain resources. The IMM has recommended that removing the incentive rebuttal provision from the proposal would make the buyer-side mitigation review more predictable and capable of being administered more reliably and with less subjectivity.	Filed Comments with FERC on MOPR Elimination and Buyer-side Mitigation Rules (Apr 2022)	The ISO /NEPOOL proposal was approved by FERC. The IMM will keep this recommendation under review, which will be informed by implementation experience.	Medium
2021-1	**Develop Offer Review Trigger Price (ORTP) for co-located solar/battery facilities** Under the current rules, the ORTP for a co-located battery and solar project is based on the weighted average of the individual technologies. This results in a value that is below the true "missing money" for the combined resource, allowing such resources to offer in at prices below competitive levels without review and mitigation, and undermining the protections put in place by the minimum offer price rule (MOPR). In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.	Filed Comments with FERC on ORTP Recalculation (Apr 2021)	The value of this recommendation is low in the context of the elimination of MOPR in FCA 19.	Low

ID	Recommendation	Report Source	Status	Priority Ranking
2020-1	***Reference level flexibility for multi-stage generation*** Given that recommendation 2017-1 below is not part of the ISO's work plan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	Winter 2020 QMR (May 2020)	Not in the scope of the ISO's current work plan.	Medium
2018-1	***Unoffered Winter Capacity in the FCM*** The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e., their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g., monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.	Fall 2018 QMR (Mar 2019)	While this recommendation remains open it may need to be reviewed by the IMM in the context of the design effort to revise the methodology for calculating qualified capacity (the resource capacity accreditation project).	Medium
2017-1	***Treatment of multi-stage generation*** Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics. [1]The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. Expanding the current pseudo-combined cycle (PCC) rules- Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes, or b. Adopt multi-configuration resource modeling capability- More	Fall 2017 QMR (Feb 2018)	Not in the scope of the ISO's current work plan.	Medium

ID	Recommendation	Report Source	Status	Priority Ranking
	dynamic approach to modeling operational constraints and costs of multiple configurations.			
2016-1	***Improving price forecasting for Coordinated Transaction Scheduling (CTS)*** There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have typically been in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	2016 AMR (May 2017)	The IMM will continue to assess and report on the price forecasting issue. The ISO is also periodically reporting on the forecast accuracy. Future improvements are not in the scope of the ISO's current work plan.	High
2016-2	***Analyzing the effectiveness of Coordinated Transaction Scheduling*** ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	2016 AMR (May 2017)	Related to the item above (Improving price forecasting for CTS). Not in the scope of the ISO's current work plan.	Medium
2015-1	***Corporate relationships among market participants*** The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	Q2 2015 QMR (Oct 2015)	The project is not in the scope of the ISO's current work plan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium
2015-3	***Pivotal supplier test calculations*** The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	2015 AMR (May 2016)	IMM and ISO to assess the implementation requirements for this project.	Medium
2015-2	***Forward reserve market and energy market mitigation*** The ISO develop and implement processes and mechanisms to resolve the market power concerns associated with exempting all or a portion of a forward reserve resource's energy supply offer from energy market mitigation.	Q2 2015 QMR (Oct 2015)	The IMM will evaluate revising or eliminating mitigation exemptions for FRM resources to resolve the market power issues. [The ISO is proposing to sunset the FRM with the implementation of DASI in Q1 2025]	Low

ID	Recommendation	Report Source	Status	Priority Ranking
2013-1	***Limited energy generator rules*** The ISO modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	2013 AMR (May 2014)	Further analysis required by the ISO to assess whether specific rule or procedure improvements are appropriate. The IMM will continue to monitor the use of the limited-energy generation provision and address any inappropriate use on a case-by-case basis.	Low
2010-1	***NCPC charges to virtual transactions*** The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.	2010 AMR (Jun 2011)	The ISO had planned to review this issue as part of the conforming changes related to the implementation of Day Ahead Ancillary Services project.	Medium

Section 1
Overall Market Conditions

This section provides an overview of the key trends in the wholesale markets. It covers the underlying supply and demand conditions behind those trends, and provides important context to the more detailed discussions on market outcomes and performance in later sections of this report.

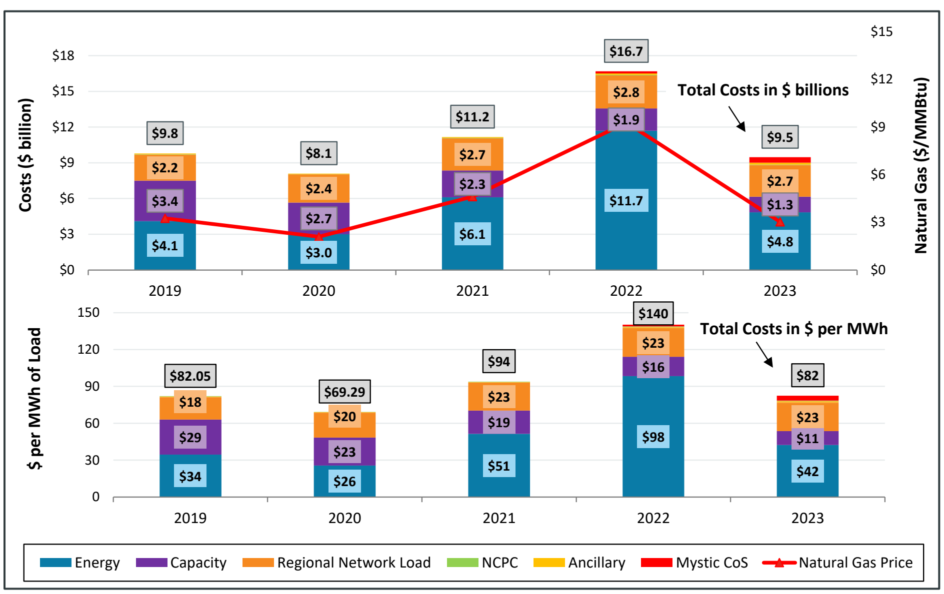
1.1 Wholesale Cost of Electricity

An overview of wholesale electricity costs over the past five years is presented below, with a focus on the significant factors that influenced changes in cost categories, particularly fluctuations in natural gas prices.

> ***Key Takeaways***
>
> In 2023, the wholesale market cost of electricity was \$9.5 billion, a decrease of 43% compared to 2022 costs (of \$16.7 billion). The reduction was largely due to lower energy costs (\$4.8 billion, down by 59%), which in turn were driven by lower natural gas prices. Following historically high energy costs and natural gas prices in 2022, overall levels in 2023 returned to a typical range, particularly levels seen between 2015 and 2021.Natural gas prices fell by 67% in 2023 (\$3.04/MMBtu) compared to 2022 (\$9.28/MMBtu) and continued to be the primary driver of energy costs.

The relationship between wholesale electricity costs and the price of natural gas is evident in Figure 1-1 below, which shows the breakdown of the cost of electricity, along with average natural gas prices.

Figure 1-1: Wholesale Costs (\$ billions and \$/MWh) and Average Natural Gas Prices



Energy costs account for the largest share of wholesale electricity costs; over half (51%) in 2023. Total energy costs of $4.8 billion were down significantly (by 59%) from a sixteen-year high in 2022 ($11.7 billion).[15] Natural gas prices decreased substantially, falling to $3.04/MMBtu (down 67%), and drove reductions in energy costs.[16]

The downward pressure of natural gas on energy costs was partially offset by supply mix changes that resulted in the need for relatively more expensive generation, putting upward pressure on energy prices. First, nuclear generation was down by about 480 MW per hour on average, primarily due to planned refueling outages. Second, the average total thirty-minute reserve margin declined by 120 MW in 2023, driven by the planned outage of flexible generation capacity that led to tighter system conditions in the fall. Further, low-priced net imports decreased by 190 MW in 2023 compared to 2022.

Regional network load (RNL) costs, or transmission costs, includes transmission owners' recovery of amortized infrastructure investments, maintenance, operating, and reliability costs, and together accounted for a large share (28%) of total wholesale costs in 2023.[17] Transmission and reliability costs were $2.7 billion, $111 million (4%) less than 2022 costs. The change was due to a decrease in infrastructure costs, which make up the majority (around 95%) of RNL costs.[18] Investments in the transmission network to maintain reliability have fallen in recent years; in the past five years (2019-2023) investment totaled $1.76 bn. compared to $4.37 bn. in the preceding five years (2014-2018).[19] However, the ISO's 2050 Transmission Study indicates that significant future investment will be needed to upgrade the network in order to incorporate high levels of renewable generation to meet state decarbonization goals.[20] In recent years, major New England transmission projects have included the Greater Boston and SEMA/Rhode Island reliability upgrades. Significant levels of reliability-driven transmission investments have notable impacts on the energy and capacity markets, including low levels of

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[15] Energy costs in 2023 were the highest since 2008, due to significant increases in natural gas prices. Natural gas prices were driven by a combination of market conditions and events at an international and national level, in addition to regional New England winter issues. These factors included the Russian-Ukrainian conflict and the significant uptick in international demand for Liquefied Natural Gas (LNG), higher US demand and periods of sustained cold weather in New England. See IMM's *2022 Annual Markets Report* (June 5, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

[16] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, Tennessee gas pipeline Z6-200L, Tennessee North gas, Tennessee South gas, and Maritimes and Northeast. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 10 on D+2.

[17] Reliability costs include: resources retained for reliability (RFR) in the Forward Capacity Market (FCM), voltage support, high-voltage control, and system restoration.

[18] The annual figure is the sum of the monthly Total RNL Costs as reported in the ISO's *Monthly Regional Network Load Cost Reports*, available at https://www.iso-ne.com/markets-operations/market-performance/load-costs/

[19] See ISO New England's *2023 Regional System Plan* (November 1, 2023), p 24, Figure 1-4, available at https://www.iso-ne.com/static-assets/documents/100005/20231114_rsp_final.pdf

[20] See ISO New England's *2050 Transmission Study* (February 12, 2024), pp 16-20, Section 2 (Key Takeaways), available at https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

congestion, fewer out-of-merit reliability commitments and associated NCPC payments, and fewer capacity zones.

Capacity costs comprise payments to supply resources in the Forward Capacity Market. They accounted for 14% of wholesale costs in 2023, decreasing by 30% due to lower auction clearing prices in FCA 13 (for delivery in 2022/23) and 14 (2023/24), which were conducted in 2019 and 2020, respectively.[21] Capacity clearing prices have fallen consistently over the past five delivery periods, from $7.03/KW-month in FCA 10 (2019/20) to $3.80/kW-month in FCA 13 and $2.00/kW-month in FCA 14 (an average of $2.90/KW-month for calendar year 2023), reflecting lower installed capacity requirements and an increased surplus due to new entry outpacing retirements.

Ancillary service costs include payments to supply resources for providing operating reserves and regulation services, and the costs of the Inventoried Energy Program (IEP). Ancillary service costs totaled $164 million in 2023, up $41 million on 2022 costs due to higher forward reserve payments, and the start of the IEP. The increase in forward reserve payments was primarily attributable to increased supply offer pricing by participants with resources capable of providing ten-minute non-spinning reserves.[22] The IEP began in December 2023, and provides an interim solution to compensate and incent inventoried energy during the winter seasons of 2023/24 and 2024/25. We discuss the IEP further in Section 9.1.1.

Net Commitment Period Compensation (NCPC) costs, or uplift, covers supply resource productions costs not recovered through energy prices. NCPC totaled $34 million in 2023, down 35% from $53 million in 2022, comprising a small component of total energy costs at 0.7%. First contingency or "economic" payments made up 93% of total NCPC payments, and fell by $18.3 million consistent with the reduction in energy market payments. Despite the decrease, NCPC made up 0.7% of energy market payments in 2023, up from 0.5% in 2022. The increase in NCPC as a share of energy market payments was driven by payments to fast-start out-of-merit resources in late 2023.

Mystic Cost-of-Service Agreement Payments: In early 2019, the Mystic 8 and 9 generators sought to retire through the capacity market but were retained by the ISO due to fuel-security concerns impacting power system reliability. From June 2022 through May 2024, the generators will receive supplemental payments to offset operating costs per their cost-of-service agreement (Mystic CoS).[23] These payments totaled $460 million in 2023, about 5% of total wholesale costs.

[21] In the 2022 report, capacity costs also included supplemental payments under the Cost-of-Service Agreement to the Mystic 8 and 9 generators. This report breaks the supplemental payments out into a separate category.

[22] The ancillary services total presented here does not include blackstart and voltage costs. Those costs are included in the RNL category.

[23] Under the Mystic CoS, Mystic 8 and 9 have an Annual Fixed Revenue Requirement (AFRR), which is the amount they need to operate for the commitment period. Capacity Supply Obligation (CSO) payments are not enough to cover the AFRR, and the supplemental payments fill the gap. Any additional revenues they receive are netted so revenues are capped at the AFRR.

1.2 Fuel and Emissions Costs

Fuel and emissions costs are major drivers of electricity prices. While emissions allowance prices are a smaller share of electricity production costs for fossil fuel-fired generators, CO_2 costs have been increasing and comprised a larger share of production costs in 2023.

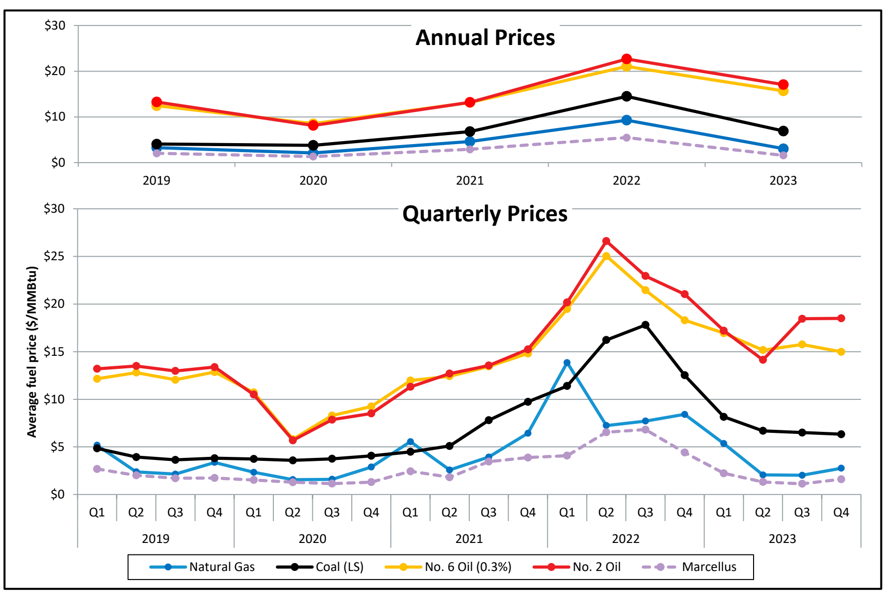
Key Takeaways

Prices for all major fuel categories fell in 2023, with natural gas falling 67% to $3.04/MMBtu, and No. 2 and 6 oil products both falling by 25% to $17.08/MMBtu and $15.71/MMBtu, respectively. While prices were elevated in 2022 following the Russian invasion of Ukraine and resulting uncertainty in global energy markets, prices returned to relatively normal levels in 2023 as natural gas stocks stabilized in both the United States and Europe during mild weather conditions.

CO_2 emissions costs increased slightly in 2023 relative to prior years, but with lower fuel costs, comprised a larger share of generation production costs; from 6% for oil generation to 20%-30% for natural gas generation. CO_2 emissions costs were therefore a notable driver of energy prices. We estimate that CO_2 contributed about $6/MWh to the average annual energy price on a load-weighted basis (or 15% of $39/MWh) and about $690 million to total energy costs (or 14% of $4.8 billion).

The annual and quarterly trends in fuel prices are shown in Figure 1-2 below.

Figure 1-2: Average Fuel Prices by Quarter and Year



Natural Gas

In 2023, natural gas prices fell to the lowest level since 2020 due to mild weather conditions and abundant natural gas supply. At a national level, winter (Q1) temperatures were milder in 2023 than in 2022, reducing heating demand and natural gas prices.[24] Natural gas supply grew in 2023 as U.S. natural gas production set record highs and natural gas stocks rose above five-year averages, leading to low gas prices both at trading hubs and within New England.[25] Inexpensive natural gas contributed to low LMPs throughout the year as natural gas-fired generators comprised 55% of average hourly generation and set the real-time price 84% of the time.

Oil

No. 2 oil prices averaged $17.08/MMBtu and No. 6 oil prices averaged $15.71/MMBtu in 2023, both down 25% from 2022, following falling crude oil prices in 2023.[26] Despite the decline in oil prices, average daily oil generation fell 83% in 2023 (to just 37 MW per hour) relative to 2022 as the system experienced few periods of tight system conditions or prolonged cold spells that brought oil-fired generation into the economic merit order.

Coal

Coal prices fell by 52% in 2023, averaging $6.91/MMBtu as domestic demand fell.[27] Coal-fired generation remains the least active thermal generation source in New England, providing less than 0.2% (21 MW per hour) of total native generation in 2023.

Emission Allowances

New England has two carbon-reducing cap-and-trade programs that impact production costs and electricity prices:[28] (1) *The Regional Greenhouse Gas Initiative* (RGGI), covering generators in all New England states, and (2) *The Electricity Generator Emissions Limits* (referred to as the MA EGEL program below) under the Global Warming Solutions Act (GWSA), covering only Massachusetts generators.[29]

The average cost of emissions by generator fuel type for each program in the context of short-run fuel costs is illustrated in Figure 1-3.

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[24] For a more detailed discussion of the impacts of weather on energy markets, see Section 3.3.1.

[25] See EIA reports The United States begins the winter with the most natural gas in storage since 2020 (December 7, 2023), available at https://www.eia.gov/todayinenergy/detail.php?id=61044 and We expect Henry Hub natural gas spot price to average under $3.00/MMBtu in 2024 and 2025 (January 11, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=61223#

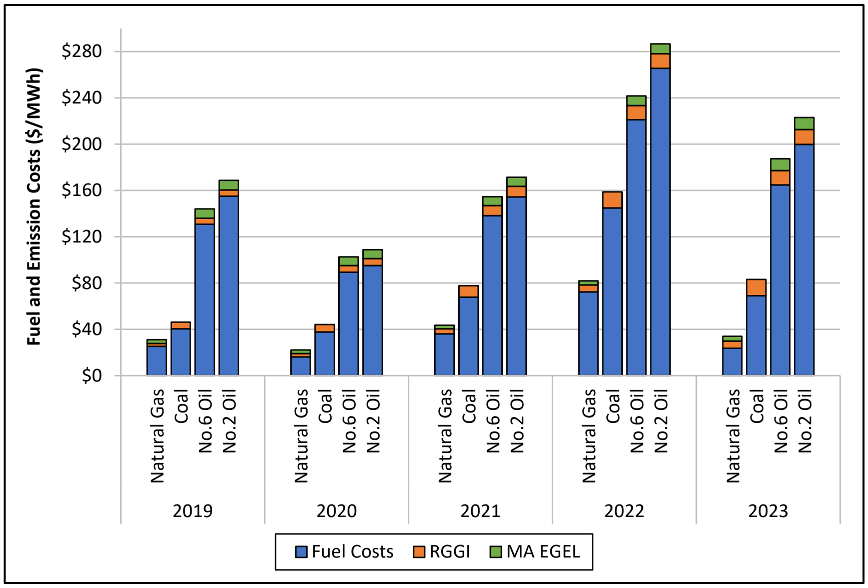
[26] See EIA report *Brent crude oil prices averaged $19 per barrel less in 2023 than 2022* (January 2, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=61142

[27] The International Energy Agency report *Coal 2023 Analysis and forecast to 2026* (2023), available at https://www.iea.org/reports/coal-2023/executive-summary expected 2023 coal demand to decline by 20% in the United States, following multi-year trends.

[28] Both of these programs are discussed in more detail in Section 3.2.1.

[29] See the Massachusetts Department of Environmental Protection's page *Electricity Generator Emissions Limits (310 CMR 7.74),* available at https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

Figure 1-3: Annual Estimated Average Costs of Generation and Emissions[30]



As emission prices rose and fuel prices dropped in 2023, emissions contributed to a higher proportion of overall energy production costs. In 2023, the average estimated costs of the *RGGI* program increased just 0.7% for most fossil fuel-fired generators year-over-year: natural gas ($6.19/MWh, 26% of production costs), coal ($13.98/MWh, 17% of production costs), No. 6 oil ($12.78/MWh, 7%), and No. 2 oil ($12.79/MWh, 6%). Meanwhile, the average estimated costs of the *Massachusetts EGEL* program increased 23% in 2023 to $4.12/MWh for the average natural gas combined cycle generator, bringing the total emissions costs to $10.31/MWh or about 30% of production costs for a typical combined cycle in Massachusetts.

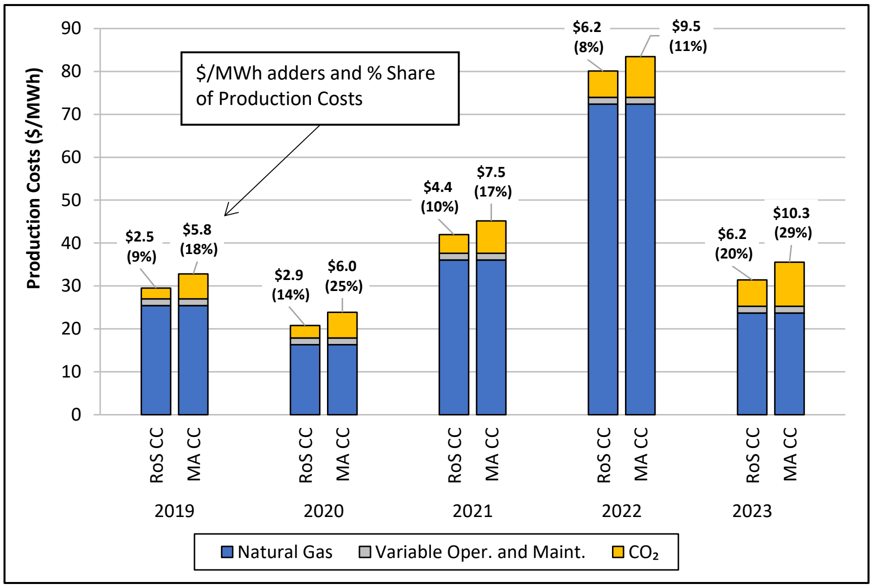
Estimation of the impact of CO_2 prices on LMP and other market outcomes

Since 2019, the price of CO_2 emission allowances have increased significantly (by almost 150% and 25% for RGGI and MA EGEL credits, respectively). Coupled with lower natural gas prices in 2023, CO_2 costs contributed to a higher proportion of overall fossil-fuel generation costs. Figure 1-4 below illustrates the share of CO_2 costs and estimated production costs for a typical combined cycle generator located in Massachusetts (MA), in which RGGI *and* MA EGEL apply, and the rest of the system (RoS), in which RGGI applies.[31]

[30] IMM standard generator heat rates and fuel emission rates are used to convert $/ton CO_2 prices to $/MWh generation costs. MA EGEL-associated costs were removed for coal because there are currently no coal-fired generators affected by the MA EGEL program.

[31] The costs are based on an average heat rate of 7.8 MMBtu/MWh and the average fleet-wide variable operations & maintenance (VOM) costs for combined cycles, excluding duct-firing ranges. Start-up and no-load VOM is excluded.

Figure 1-4: Breakdown of Combined Cycle (CC) Production Costs by Component



In 2023, CO_2 emission costs comprised about 20% to 30% of energy production costs for a typical combined cycle generator, depending on its location. Since natural gas generation makes up the majority of supply and the vast majority of price-setting supply (84% in the real-time market in 2023), CO_2 costs were a key driver of wholesale energy costs. Based on our simulation of the day-ahead energy market for 2023, we estimate that CO_2 contributed about $6/MWh to the average annual energy price on a load-weighted basis (or 15% of $39/MWh) and about $690 million to total energy costs (or 14% of $4.8 billion).[32] The estimated value of emissions credits in 2023 was $380 million.[33]

The net costs of the CO_2 emission programs are significantly lower (than the estimated wholesale energy cost impact) as the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs, clean and renewable energy. For instance, the majority of auction proceeds from RGGI are invested by the New England States in energy efficiency programs, which have had a significant impact on reducing wholesale demand and wholesale energy costs (see Section 1.5).[34] Similarly, the majority of proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions.[35]

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[32] The simulation study compared two cases; the first based on actual supply offers and the second with the daily price of CO_2 emissions for both RGGI and MA EGEL programs subtracted from supply offers.

[33] The value of emissions is estimated using reported monthly emissions data for New England generators for 2023 sourced from the EPA together with the monthly average prices for RGGI and/or MA EGEL from an external vendor. EPA *Clean Air Markets Program Data* is available at https://campd.epa.gov/data

[34] See RGGI's *Investments of Proceeds* reports, available at https://www.rggi.org/investments/proceeds-investments#:~:text=The%20RGGI%20states%20issue%20CO,strategic%20energy%20and%20consumer%20programs

[35] See *310 CMR 7.74 Public Hearing Draft to Final Redline*, Allowance Auction Procedures (6.h.1.i.), available at https://www.mass.gov/doc/310-cmr-774-amendments-to-electricity-generator-emissions-limits-0/download

1.3 Supply Conditions

Below, we present an overview of New England's *native* generation and capacity mix by fuel type, location, and age. The composition of the system supply portfolio provides context to the relationship between fuel and wholesale prices, as well as emerging operational challenges. This section also looks at the flows of power between New England and its neighboring control areas.

Key Takeaways

Natural gas-fired generators are the single largest resource type in terms of both capacity and energy output, making up approximately one-half of overall contracted capacity in the Forward Capacity Market (FCM) and electricity supply in the energy market.

There was relatively little change in the composition of capacity in 2023. The second largest resource type was oil-fired generation, providing roughly 20%. Renewable or policy sponsored resources, such as solar, wind, and battery storage, have shown modest increases in capacity. However, future capacity additions contracted in forward auctions consist of large wind, solar, and battery storage projects, which will displace older gas-, oil- and coal-fired generation. The retirement of the Mystic 8 and 9 combined cycles will remove over 1,400 MW of gas-fired generation effective June 2024.

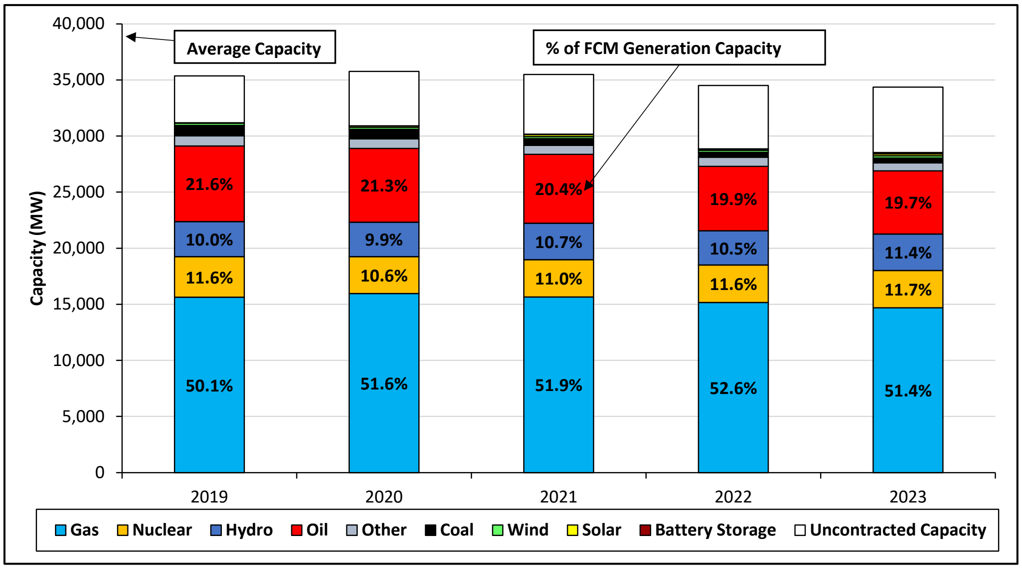
In terms of energy production, the share of natural gas generation was up slightly on 2022 (48% vs. 45%) due to planned and unplanned outages of nuclear generators, as well as reductions in net interchange from the Canadian provinces. Nuclear generation and imports contributed 20% and 13% to total supply, respectively; combined with natural gas making up over 80% of the supply mix.

Generation Capacity

Capacity by generator fuel type in Figure 1-5 below shows the breakdown of total capacity contracted in the FCM, as well as capacity without a capacity supply obligation.[36] The black dashed line shows the Net Installed Capacity Requirement (Net ICR) less contracted demand response and import capacity. Total capacity is higher than actual generation and demand to ensure sufficient operating reserves and account for uncertainty in supply availability.

[36] We calculate "uncontracted capacity" as the total maximum net output of the generation fleet minus the total contracted capacity of the generation fleet.

Figure 1-5: Average Capacity by Fuel Type[37]



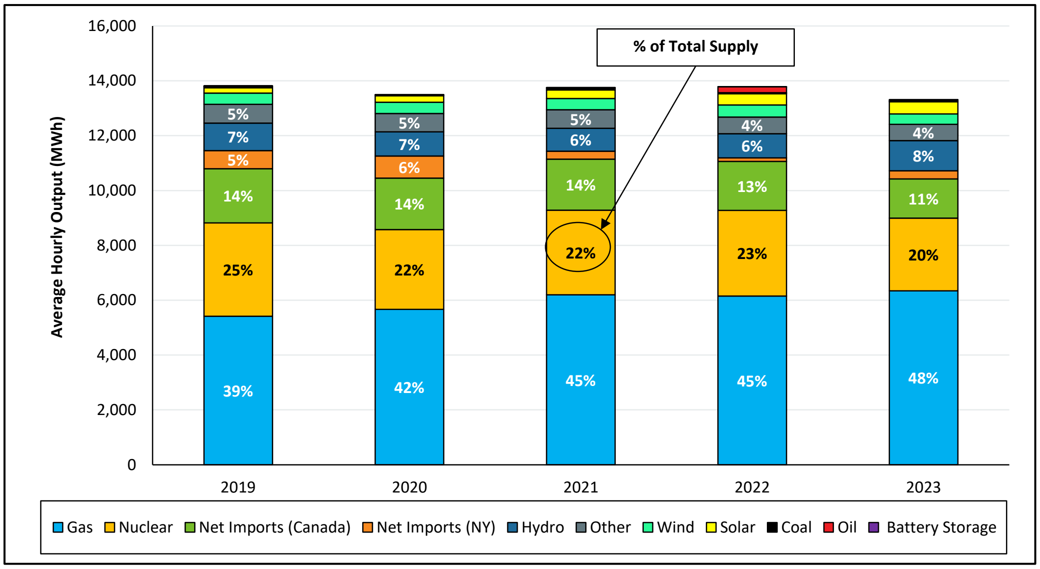
Average generation capacity decreased by just 1% year-over-year, from 28,900 MW in 2022 to 28,500 MW in 2023, driven by steady decreases in the net installed capacity requirement (Net ICR) and slightly more uncontracted FCM capacity. Natural gas generation continues to make up the most capacity of any fuel source, accounting for around 51% (14,700 MW) of total average generator capacity in 2023. No single fuel type saw a significant change in capacity share in 2023.

Energy Supply Mix

Energy production by fuel type has exhibited minor changes on average as illustrated in Figure 1-6 below. The figure shows a breakdown of hourly average supply (MWh produced, averaged across all hours) by fuel type for native generation, along with average net interchange with neighboring control areas.

[37] The "Coal" category includes generators capable of burning coal and dual-fuel generators capable of burning coal and oil. The "Other" category includes active capacity demand response, landfill gas, methane, refuse, steam, and wood.

Figure 1-6: Average Output and Share of Electricity Supply by Fuel Type



Energy supply decreased slightly in 2023, in line with decreased loads.[38] Natural gas generation continued to account for the largest share (48%) of total supply, more than two times the second largest fuel type (nuclear). Nuclear generation decreased in 2023 due to planned refueling outages, and to a lesser extent, forced outages. Natural gas and hydro generation output each increased relative to 2022, providing more baseload generation in the absence of nuclear energy.

While their share of native generation is small, solar and wind production remain a key focus of energy policies that will impact New England's energy landscape over the coming years. State and federal policies have driven additional wholesale (front-of the-meter) solar energy production and wind energy production.[39] Solar and wind accounted for 4.3% of energy supply in 2019 and increased to 6.1% in 2023. Battery storage output, while also relatively small, increased in 2023, with an hourly average energy output of 27 MW in 2023, more than triple that observed in 2022, and more than ten times that observed in 2019.

Net interchange from Canada and New York averaged over 1,700 MW per hour, meeting 13% of New England demand. The level of net interchange continued to decline from 2020. The significant driver for this year's decline was a decrease in imports over the Canadian interfaces, particularly over the Phase II interface. Lower reservoir levels in Québec led to a 20% (or 264 MW) reduction in imports into New England over the Phase II interface. At the Highgate interface, curtailments of real-time transactions led to a 39% (or 85 MW) decline in average net imports. Even with the reduction in net interchange from Canada, imports from the Canadian provinces comprised 83% of total net interchange in 2023.

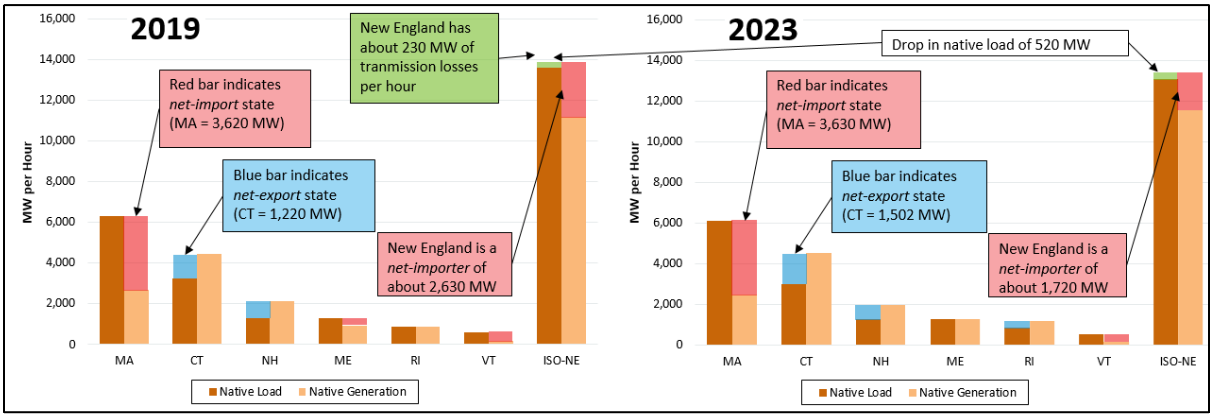
[38] Section 3.3 provides more detail on changes in load.

[39] Section 3.3 discusses the impact of solar generation on load from both behind- and front-of-the-meter solar.

Generation and Consumption by State

A breakdown of energy production and consumption within each state and aggregated across the ISO-NE market is shown in Figure 1-7 below.[40] Darker shaded bars show state load, while lighter shaded bars show state generation. The red and blue bars simply show the difference between production and consumption; the red bars illustrate net imports into each state, and the blue bars net exports out of the state.[41,42]

Figure 1-7: Average Electricity Generation and Load by State[43]



Given their larger populations, Massachusetts and Connecticut are the largest consumers and producers of electricity within the six-state footprint, comprising 70% and 60% of total load and generation, respectively. Massachusetts, the state with the most load, consumed an hourly average of 3,620 MWh more than it generated in 2023. These results are consistent with 2019 levels and reflect the plateau in load growth across the region in recent years. Connecticut generated an hourly average of 1,500 MWh more than it consumed in 2023, up from 1,220 MWh in 2019. New gas-fired generators built in Connecticut over the past five years accounted for the majority of new generation in the state. In addition, as discussed in Section 3.1.1, Connecticut's annual average prices were approximately 2% lower that the Hub prices during 2023. This reflects both surplus supply conditions with relatively cheaper generation in that state and areas of congestion that limit the export of that supply.

The total ISO-NE bar summarizes two key trends. First, average native load in New England fell by 520 MW per hour compared to 2019. This is largely due to the impact of energy efficiency and behind-the-meter solar generation, which are discussed in Section 3.3 below. Second, New England continues to be a net importer of power, although its reliance on imports fell. In 2023, 13% (or 1,720 MW per hour) of New England's electricity demand was met by energy imported from neighboring areas, primarily due to lower imports over the Phase II interface.[44]

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[40] The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions.

[41] The green bar for ISO-NE illustrates losses as energy flows through the system.

[42] Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada), but refer to any imports from outside the state.

[43] Note: MW values are rounded to the nearest 10 MW.

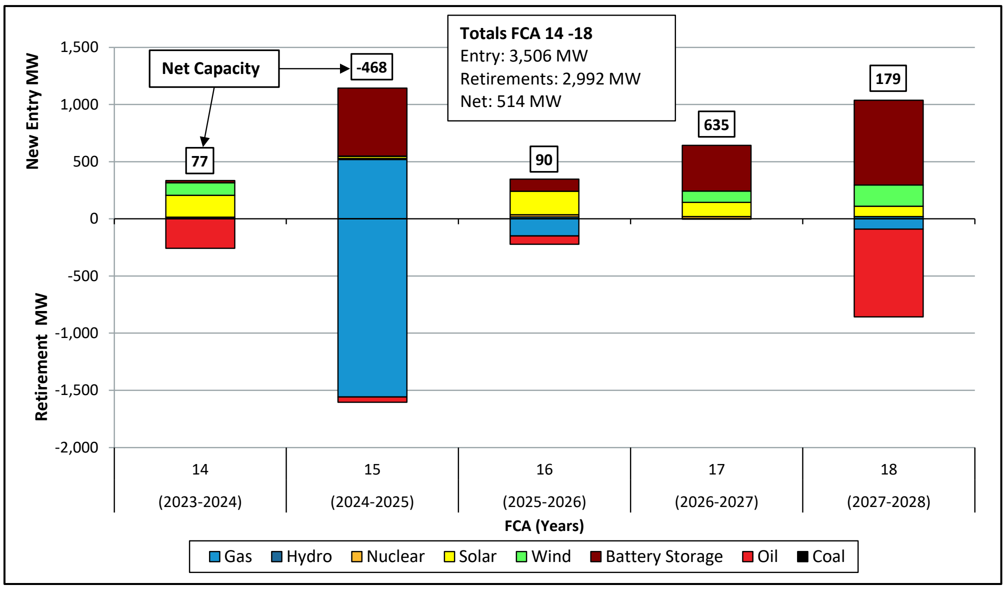
[44] More detail on this trend is provided in Section 4.

Capacity Additions and Retirements

The supply mix in New England is evolving. As generators age, they require increased maintenance and upgrades to remain operational, thereby increasing their costs to operate. Older coal- and oil-fired generators in New England also face higher compliance costs associated with public policies intended to reduce greenhouse gas emissions.

Generator additions and retirements in each Forward Capacity Auction (FCA), beginning with FCA 14 (CCP 2023/24) are shown in Figure 1-8 below. Net surplus capacity, or new capacity minus retired capacity, is also displayed for each auction.

Figure 1-8: Generator Additions and Retirements



Wind, solar, and battery storage have accounted for almost two-thirds of all new capacity that has cleared in the FCM for the capacity commitment periods from 2023-2024 onward (i.e., since FCA 14). These technology or fuel categories will comprise an increasing share of supply over the coming years, playing a significant role in meeting the states' decarbonization goals. However, while battery storage resources currently qualify in the FCM close to their nameplate capacity, their capacity value will likely fall significantly under the proposed new marginal accreditation methodology due to their lower contribution in the event of multi-hour unserved energy events.[45] There have been no significant additions to gas generation capacity in the past five auctions; the addition of gas capacity in FCA 15 was largely comprised by a repowering project of the existing Ocean State combined cycle generator.

Most retirements include older oil-, and gas-fired generators. The largest retirements occurred during FCA 15 with the delayed retirement of over 1,400 MW of gas-fired generation at the Mystic station. Oil capacity retirements in FCA 18 were largely attributable to resources at the Middletown station in Connecticut.

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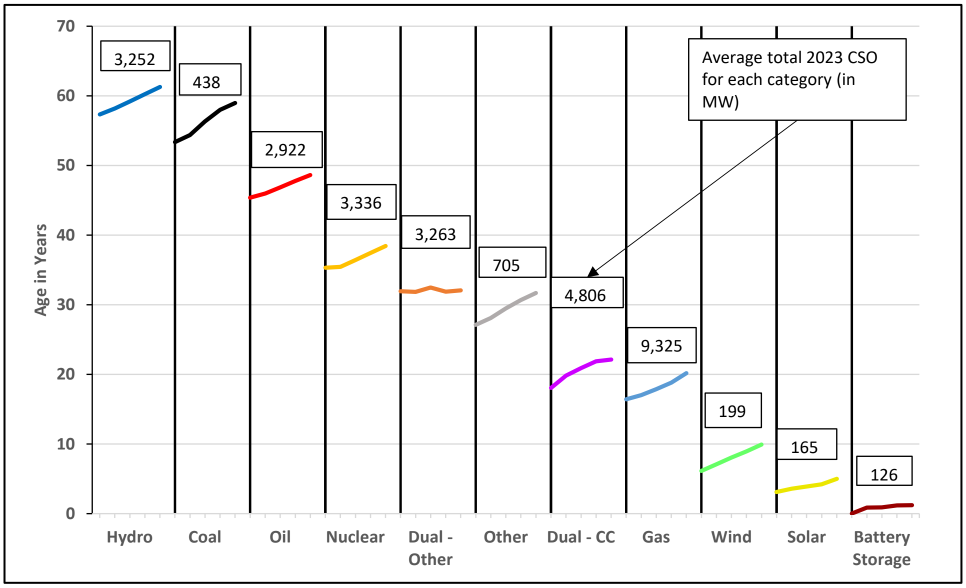
[45] See ISO's presentation, *Resource Capacity Accreditation in the Forward Capacity Market*, *FCA 18/19 Accreditation Sensitivity Analysis, Part 2,* by Dane Schiro (April 9-10, 2024), available at https://www.iso-ne.com/static-assets/documents/100010/a03d_mc_2024_04_09_10_impact_analysis_sensitivity_results.pdf

Average Age of Generators by Fuel Type

The average age of New England's generation fleet is illustrated in Figure 1-9, and provides some insight into how the supply mix is evolving and potential future challenges for the region.[46] The average age of New England's generators in 2023 ranged from one year (battery storage) to 61 years (hydro), with a weighted-average system age of 32 years.

Figure 1-9: Average Age of New England Generator Capacity by Fuel Type (2019 - 2023)[47]



The older categories of supply assets on the left side of the graph have, on average, been in service for over 30 years and typically require increased maintenance and upgrades to remain operational, thereby increasing costs. Fossil fuel-fired generators in New England also face higher compliance costs associated with public policies intended to reduce greenhouse gas emissions. Much of this capacity has energy security attributes, which are particularly important to the region during winter cold spells when natural gas prices are high and pipeline capacity is limited. Oil generation comprises most of the capacity considered by the ISO to be "at risk of retirement", with an average age approaching 50 years.[48]

On the right hand side of the graph, wind, solar, and battery storage remain the newest generation fuel types; all three groups of generators had an average age at or below 10 years. These technology or fuel categories will comprise an increasing share of supply over the coming years, playing a significant role in meeting the states' decarbonization goals.

[46] Age is determined based on the generator's first day of commercial operation. The average values are weighted by the max net output for each generator within the fuel type. If there were no retirements or new generation, we would expect each colored line to increase by one year as generators age. Either an influx of new generators or a retirement of old generators can cause a decline in average age. Data labels above the bars show average total FCM capacity in 2023 by fuel type.

[47] The "Other" category includes landfill gas, methane, refuse, steam, and wood.

[48] For an overview of generator retirements see the ISO's *Power Plant Retirements* page, available at https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements#:~:text=More%20than%205%2C200%20MW%20of,be%20retiring%20in%20coming%20years.

1.4 Demand Conditions

This section presents trends and assesses the underlying drivers of historic and anticipated energy demand, the impact of weather, energy efficiency, and behind-the-meter solar generation.

Key Takeaways

Average loads hit (at least) a 24-year low in 2023, decreasing across all quarters relative to 2022. Mild weather conditions drove declining wholesale energy demand as hourly loads were down 4% from 2022, averaging 13,096 MW. The growth in behind-the meter solar generation also had the impact of reducing wholesale load levels. While loads fell in 2023, the ISO forecasts that demand will reverse this trend in the near future, with 2032 average hourly loads projected to be over 17,000 MW on average, roughly 30% above 2023 loads.

In the FCM, the capacity needed to meet the system's reliability objective (Net ICR) has generally declined over recent capacity auctions, but increased slightly for FCA 18 to 30,550 MW; a 1% increase from FCA 17. This is generally reflective of stagnant peak load growth in recent years as well as methodological improvements in determining key inputs such as load forecasting.

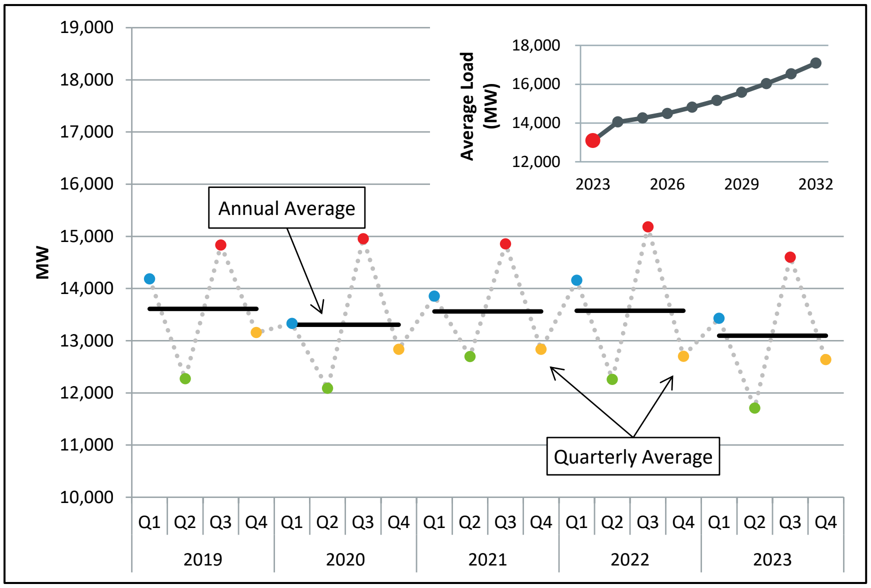
Wholesale Demand[49]

Wholesale energy demand fell in 2023 as hourly load averaged 13,096 MW, down 4% from 2022, due to mild weather conditions throughout the year and continued growth in energy efficiency and behind-the-meter photovoltaic generation. Annual and quarterly average loads from 2019 to 2023 are shown in Figure 1-10 below, alongside an inset graph illustrating projected load growth.[50]

[49] Wholesale electricity demand or Net Energy for Load (NEL) excludes both electricity demand that is met by behind-the-meter generation and asset-related demand for pumped-storage or battery-storage facilities.

[50] To view load forecasts through 2032, see the ISO's *2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 1, 2023), available at https://www.iso-ne.com/system-planning/system-plans-studies/celt. Forecasted annual load in GWh is converted into average hourly MW values.

Figure 1-10: Average Hourly Load by Quarter and Year



Average loads hit at least a 24-year low in 2023, decreasing across all quarters relative to 2022.[51] During the peak summer months (Q3), average load (14,601 MW) fell 4% from 2022 due to lower temperatures (72^{0}F in 2022 to 70^{0}F in 2023).

While load remained largely temperature-driven in 2023, the growth in behind-the meter solar generation also has the impact of reducing wholesale load levels. This is discussed in more detail in section 1.5 below. Further, load levels are projected to increase significantly over the next decade, with 2032 average hourly loads projected to be over 17,000 MW on average, roughly 30% above 2023 loads. The gap between summer and winter peak loads is projected to decline throughout the next decade, with a change to a winter-peaking system as early as 2029.[52]

Capacity Market Requirements

The Net Installed Capacity Requirement (Net ICR) is the amount of capacity needed to meet the region's 1-in-10 year reliability standard.[53] The Net ICR value is used to anchor the administrative system demand curve for the FCA and is a significant determinant of auction clearing prices.

Trends in system capacity requirements (Net ICR, peak load forecast) and system capacity procurement (system capacity, capacity surplus) are shown in Figure 1-11 below. The Net ICR,

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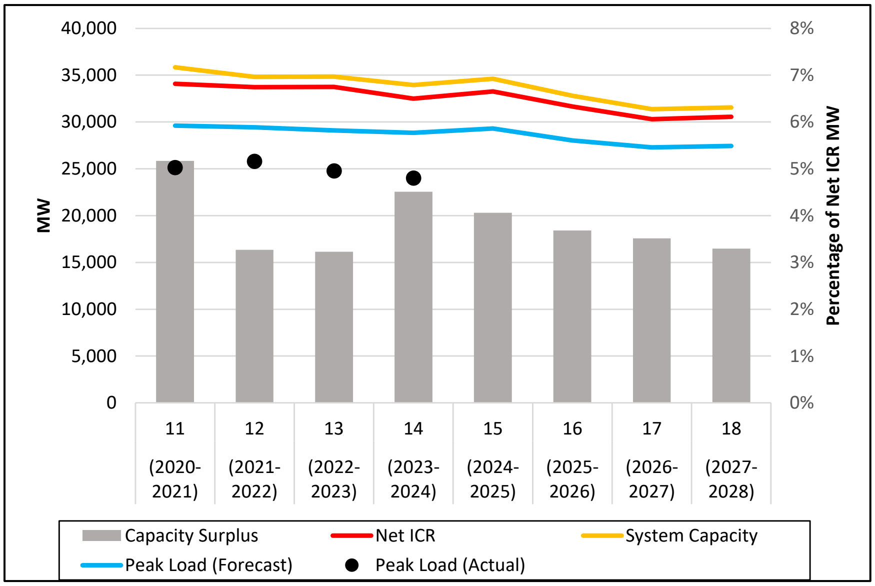
[51] Load data is only available to the IMM back to the year 2000. In 2000, load averaged 13,300 per hour.

[52] To see load projections, see the Analysis Group's *Pathways Study, Evaluation of Pathways to a Future Grid* (April 2022), available at https://www.iso-ne.com/static-assets/documents/2022/04/schatzki-et-al-pathways-final.pdf

[53] The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than one day every ten years. When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a combination of variables such as anticipated demand of local consumers and anticipated supply from neighboring control areas.

peak load forecast, and System Capacity are represented as line series aligned with the left axis. Capacity surplus as a percentage of Net ICR is represented as a bar series aligned with the right axis.

Figure 1-11: NICR, Peak Load Forecast, and Capacity MW for FCA 11-18



Net ICR and peak load forecast have steadily declined since FCA 11, with minimal change for the two most recent auctions.[54] This is generally reflective of stagnant peak load growth as well as methodological improvements in determining key inputs such as load forecasting. Actual peak loads have trailed the forecast for commitment periods associated with FCAs 11-14. Similar to average load projections discussed previously, peak loads are projected to increase by over 2,400 MW from 2023 to 2032 and will drive higher capacity requirements for future auctions.[55]

1.5 The Evolving Demand Landscape in New England

The New England states continue to invest heavily in the power sector as a key means of meeting their decarbonization goals, including in energy efficiency measures (EE), storage and renewable supply, at both the wholesale market and retail level (behind-the-meter or BTM generation). In particular, there has been notable growth in solar generation, while offshore wind and energy storage capacity are also expected to increase over the coming years. Below we provide an overview of the impacts of these efforts on the level and profile of wholesale electricity demand over a five-year period, and discuss impacts on wholesale market outcomes.

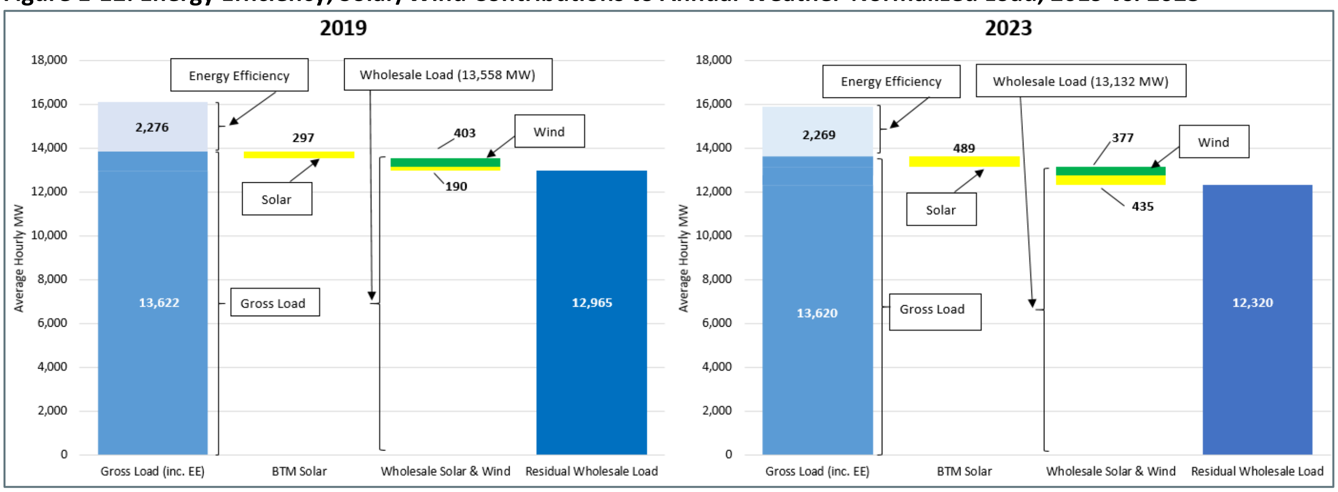
[54] For Net ICR amounts and related values for all auctions see *ISO New England Forward Capacity Market - Summary of ICR and Related Values*, available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx. The 50-50 Summer Peak Load forecast appears in the above figure.

[55] See the ISO's *2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 1, 2023), section 1.5.2, available at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

> ***Key Takeaways***
>
> The wholesale demand "duck curve" has become demonstrably more pronounced over the last five years in New England, and with solar capacity projected to double over the next 10 years, will increasingly pose challenges and opportunities for markets and system operations.
>
> Over the past five years, the growth in solar generation has changed both the level and profile of wholesale demand and energy prices, but has not led to over-supply conditions or flexibility issues in the context of lower mid-day loads and steeper evening demand ramps.

Figure 1-12 below shows the impact of EE measures and the increasing contributions of BTM and wholesale solar and wind generation to meeting the region's demand (load), by comparing 2019 to 2023.[56, 57, 58]

Figure 1-12: Energy Efficiency, Solar/Wind Contributions to Annual Weather-Normalized Load, 2019 vs. 2023



Energy efficiency has made a significant contribution to reducing load, but its growth has stalled in recent years due to rising costs of eligible EE measures and the associated EE baselines used to calculate claimable savings. While estimated gross load is also unchanged, the contribution of BTM solar has doubled in five years, from 2% to 4% of gross load, driving lower

[56] Demand is weather-normalized to allow for a clearer comparison. Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[57] Energy Efficiency is based on aggregated performance of installed measures on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment. Energy Efficiency and Demand Response Distributed Generation (DG) measures are aggregated to On-Peak and Seasonal-Peak resources. Performance of DG accounts for only 5% of energy efficiency performance.

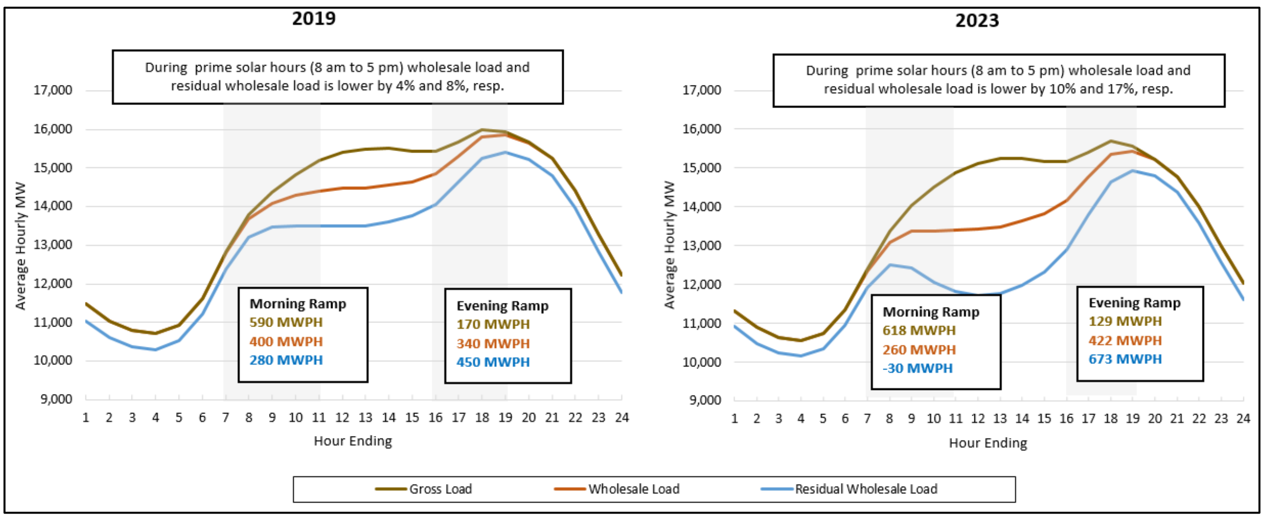
[58] Behind-the-meter solar production and energy efficiency estimates are provided by ISO New England's system planning department.

wholesale demand. Combined, wholesale solar and wind generation has also increased on a percentage basis, from 6% to 8%. However, the contribution of wind has largely remained the same throughout the past five years, at about 400 MW. Finally, demand met by remaining supply technologies, termed “Residual Wholesale Load” here, has seen an approximate 800 MW decline.[59]

Time of Day Load Profile and Peak Loads

While the overall impact of additional wind and solar has been relatively small at an annual average level, the time-of-day impacts are demonstrably more pronounced. Figure 1-13 below compares the hourly load profiles for 2019 and 2023, with emphasis on the morning (7am to 11am) and evening ramps (4pm to 7pm) periods.

Figure 1-13: Solar and Wind Impacts on Average Load Profiles, 2019 vs. 2023



There is a substantial change in the hourly load profiles, with BTM solar moderating wholesale load ramps in the morning and increasing evening load ramps. In particular, the impact on morning and evening ramps has grown; for example, the ramp in “residual wholesale load” during the evening hours has increased from 440 MW per hours to 673 MW per hour between 2019 and 2023.

The lowest demand has commonly occurred during the early morning hours, but there has been a notable increase in the frequency of minimum residual wholesale load occurring later - between 8am and 3pm. The frequency has increased from 0.3% in 2019 to 24% in 2023 with most occurrences during the shoulder seasons of spring and fall (78%). Further, with lower wholesale prices tracking lower mid-day load, we have observed changes in flexible demand[60] shifting consumption from overnight to mid-day hours, albeit with a quite moderate load impact on an annual basis.

[59] Wholesale generation that contributes to “Residual Wholesale Load” includes other forms of renewable supply including biomass and solar, and various forms of “must-run” or “price-taking” generation. However, the intent here is to segment demand contributions into new emerging technologies (typically sponsored policy resources) and existing technologies.

[60] The charging or demand assets of pumped and battery storage resources.

While less visible in the Figure 1-13 above, the impact of BTM solar has also impacted peak wholesale demand; on average the estimated reduction in the peak is up from 1.2% (200 MW) in 2019 to 2.3% (365 MW) in 2023. Moreover, when considering both wholesale solar and wind, residual wholesale peaks were lower by 4.2% (677 MW) and 5.4% (862 MW) in 2019 and 2023, respectively. The peak hour has also shifted to later in the evening between 6pm to 8pm; 90% of the daily peak load occurs during this time period compared to just 56% in 2019.

The annual peak demand hour over the past 5 years, Table 1-1 below provides estimated gross and "residual" wholesale demand and a breakdown of the drivers of peak demand reductions (solar, wind, usage). The "usage" contribution in this context captures the fact that peak load is shifting to later in the evening when load is lower. This concept is captured in Figure 1-14, which shows the profile for the peak load day (September 9, 2023).

Figure 1-14: Peak Demand Impacts, 2023

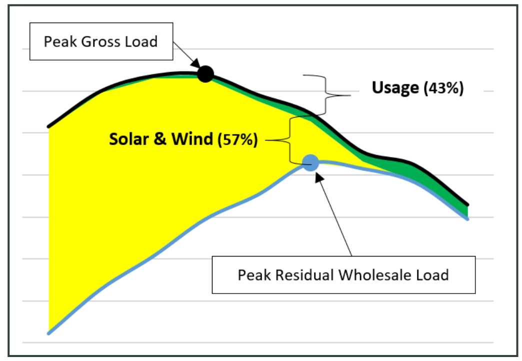


Table 1-1: Annual Peak Demand and the Impact of Solar and Wind Generation

Year	Gross		Residual Wholesale		Reduction		Contribution to Reduction		
	Peak (MW)	HE	Peak (MW)	HE	MW	%	Solar	Wind	Usage
2019	25,420	15	23,079	18	1,741	6.8%	42%	20%	38%
2020	26,288	14	24,447	18	1,841	7.0%	56%	12%	32%
2021	27,377	15	24,876	19	2,501	9.1%	19%	8%	72%
2022	26,503	15	24,045	19	2,457	9.3%	30%	7%	63%
2023	25,391	16	23,283	18	2,108	8.3%	48%	9%	43%

Solar generation on the peak load day contributed between approximately 500 MW to 1,000 MW of energy, or upwards of 50% of the difference between the gross peak and residual wholesale peak. The shift in timing of the residual wholesale peak hour to a time when load was traditionally less than the peak ("usage") explains much of the remainder of lower residual wholesale peak demand.

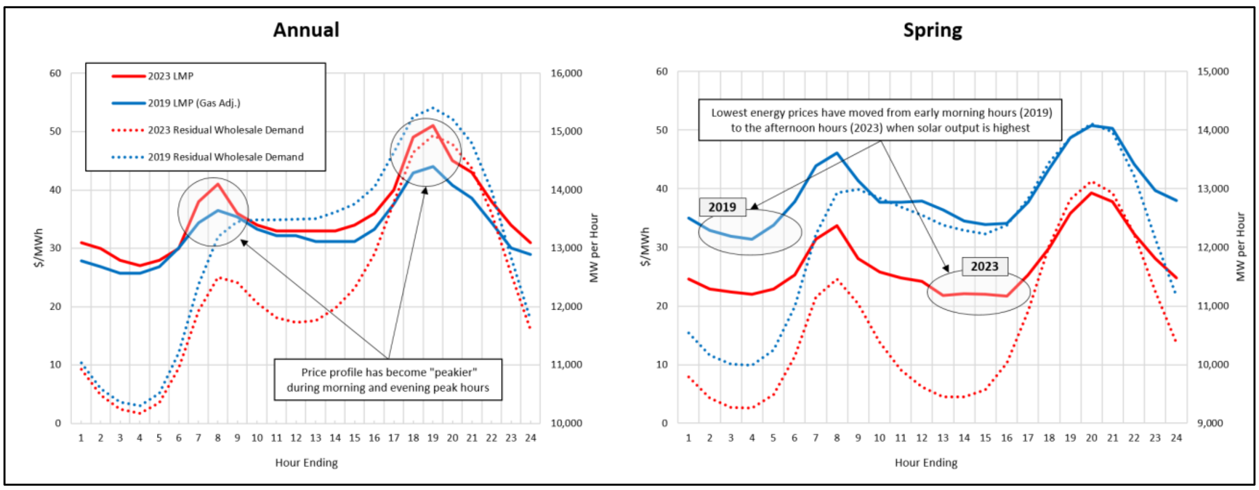
The marginal impact of solar (both BTM and wholesale generation) in reducing the peak will decline as solar installed capacity grows – eventually reducing to zero. As the daily peak load has shifted to the evening when solar generation is lower or zero, the *average* contribution of solar generation to the reduction in daily peaks has decreased from 62% in 2019 to 48% in

2023 in the case of wholesale peak demand and from 24% in 2019 to 19% in 2023 in the case of residual wholesale peak demand.[61]

Market Interactions

The changing demand landscape has discernable impacts on both the load profile as well as the level of wholesale energy prices. We do not attempt to quantify the impacts on pricing levels here, but rather focus on the time-of-day pricing impacts. However, to allow for a more direct comparison between the two bookend years in this report section, we adjust 2019 prices to account for difference in average natural gas prices (with the important caveat that other supply and demand factors also impact energy prices).[62] [63] Figure 1-15 illustrates the correlation between hourly average real-time prices (solid lines) and real-time load (residual wholesale load, dashed lines); the annual average is shown on the left, while the right panel shows the spring season (March – May), during which solar output as a share of energy demand is highest.

Figure 1-15: Hourly Average Real-Time LMP and Demand Profiles, 2019 vs. 2023



Annual: Real-time prices increase early in the morning and dip in the middle of the morning, as solar production increases and reduces load. Energy prices have become peakier during the morning ramp, and to a greater extent during the steeper evening ramp, when more expensive supply is dispatched to meet load.

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[61] To illustrate the calculation of the contribution of solar, wind and usage to the peaks, we use the 2023 annual peak: Gross peak (4pm) = 25,391 MW. Net wholesale Peak load (6pm) = 23,283 MW Gross peak (6pm) = 24,475 MW.

The reduction = 25,394 MW – 23,283 MW = 2,108 MW. At 6.00 pm, BTM = 432 MW, wholesale solar = 570 MW and wind = 190 MW.

Solar contribution to reduction = 1,002 MW (48%) and wind contribution = 190 MW (9%). The remaining reduction = 916 MW (43%) = 25,394 MW - 24,475 MW. This is the difference in electric usage between 4pm and 6pm on the same day.

[62] Average 2019 energy prices are divided by 1.35, based on natural gas prices of \$3.04/MMBtu (2019) and \$2.24/MMBtu (2023).

[63] For example, factors such as changes in the supply mix (imports, generator outages) and CO_2 costs can significantly impact LMPs, and the latter in particular was a more significant driver of 2023 LMPs compared to 2019.

Spring: Of particular note in spring, the lowest energy prices have shifted from the overnight to the early afternoon hours when solar generation output is highest.

The wholesale demand "duck curve" has become demonstrably more pronounced over the last five years, and with solar capacity projected to double over the next 10 years[64], will increasingly present both challenges and opportunities for markets and system operations. To date, we have not observed over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators curtailing supply and negative energy prices. While impacting the load ramp, solar generation has not increased the frequency with which the system is ramp-constrained; the number of ramp-constrained intervals has remained very low in the past five years. Furthermore, low energy prices in the early afternoon hours create opportunities for energy storage resources to charge, or fill their reservoirs, in anticipation of higher prices during the evening load ramp thereby smoothing out wholesale load and price changes.

1.6 Generator Profitability

The profitability metrics presented here examine whether the revenue available to proxy new generators from the suite of ISO-NE wholesale markets and other relevant markets (e.g., Renewable Energy Certificates (REC) markets), is sufficient to support the entry of certain types of new generation (gas-fired, solar and wind resources).

Key Takeaways

Following a sharp increase in profitability metrics last year due to record high energy prices, in 2023 market-based revenues were not sufficient to cover the going-forward costs of new entrant gas-fired generators. The profitability of wind and solar units in the region is intricately linked with state policies, with both technologies generally relying on additional revenue streams to those in the wholesale markets to be economically viable.

Gas-fired Generators

We present estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the revenue required from the capacity market to build a new generator, the section also highlights the incremental revenue that could be earned from dual-fuel capability and evaluates participation in the Forward Reserve Market (FRM) for a combustion turbine generator.

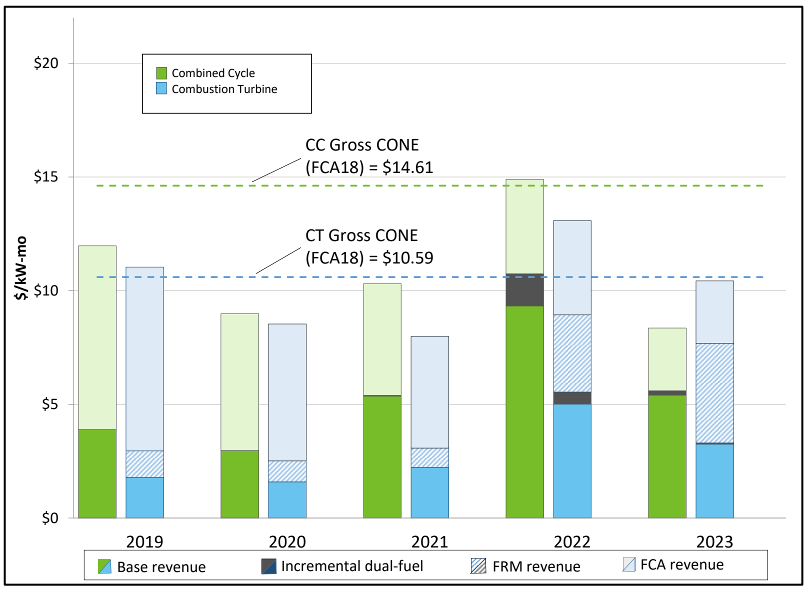
The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down

[64] See ISO New England's *Final 2023 Photovoltaic (PV) Forecast* (April 10, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/04/2_final_2023_pv_forecast.pdf

times, and economic limits.[65] The simulation model also includes a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO_2 emitted.[66]

Figure 1-16 shows the result of the simulations. Each stacked bar represents revenue components for a generator type and year. The simulation produces baseline revenue (energy and ancillary services (AS)) and incremental dual-fuel revenue numbers for 2019-2023.[67] The FCA revenue numbers shown are calculated using the actual payment rates applied to calendar years. For reference, the most recent Gross Cost of New Entry (Gross CONE) values for CC and CT generators in the Forward Capacity Auction for the 2027-2028 Capacity Commitment Period (FCA 18) are also shown in Figure 1-16. [68] The remainder of this section discusses estimated base revenues, incremental dual-fuel revenues, and FRM revenues, before comparing the total estimated revenues to Gross CONE benchmarks.

Figure 1-16: Estimated Net Revenue for New Gas-fired Generators



First, gas-fired generators' estimated base net energy and ancillary services revenues decreased significantly in 2023 when compared with 2022. Specifically, the simulation results show base revenues decreased by approximately 46% for the combined cycle generator and

[65] The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new generator).

[66] In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year. For RGGI auction data, see RGGI's *Allowance Prices and Volumes* data, available at https://www.rggi.org/auctions/auction-results/prices-volumes.

[67] Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.

[68] The Gross CONE values for the CC and CT gas-fired generators reflect Net CONE values of $10.50/kW-month and $6.33/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

approximately 40% for the combustion turbine. These large year-over-year decreases were driven partly by lower spark spreads, which decreased by 13% from the prior year.[69]

Second, unlike the prior year, dual-fuel capability did not add significant revenue to either technology type, with the stylized CT generator earning an additional $0.07/kW-month and the CC generator adding $0.20/kW-month to net revenue this year. These incremental dual-fuel capability benefits declined by nearly 90%, consistent with the reduced opportunities for oil generation due to the milder winter temperatures in 2023.[70]

Third, a CT generator can also participate in the FRM, which procures off-line reserves prior to the reserve season.[71] FRM auction for reserve seasons in the 2023 calendar year yield an additional $4.37/kW-month to the CT generator's net revenues, a 29% increase over the previous year's contribution. Note that the unusually large FRM revenue contributions in the past two calendar years are explained by the significantly higher FRM clearing prices discussed in Section 7.2.[72]

For reference, the most recent CONE revisions approved by FERC for FCA 18 establish net revenue components of $4.12/kW-month and $4.27/kW-month for combined cycle and combustion turbine generators respectively.[73,74] When compared with these benchmark estimates, the simulations suggest that estimated revenues for both the CC generator and the CT generator that participates in the FRM would be sufficient to meet these expectations.

However, these estimated revenues are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator. In recent years, capacity prices have remained low reflecting a system that is long on capacity. Consequently, total revenues from the energy and capacity markets appear insufficient to incent either type of gas-fired generator to enter the region's energy market.

Wind and Solar Units

We estimate the profitability of wind and solar power investments within the ISO-New England (ISO-NE) power market. We describe the economic viability of wind and solar projects in the

[69] Section 3.2.1 of this report discusses spark spreads in more detail.

[70] See Section 3.3 of this report for more detail.

[71] A forward reserve resource receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is very high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. Note that FRM-based revenues will no longer be available after the FRM is retired at the end of the 2024-2025 Winter period.

[72] The IMM has previously recommended reviews and updates to the forward reserve offer cap.

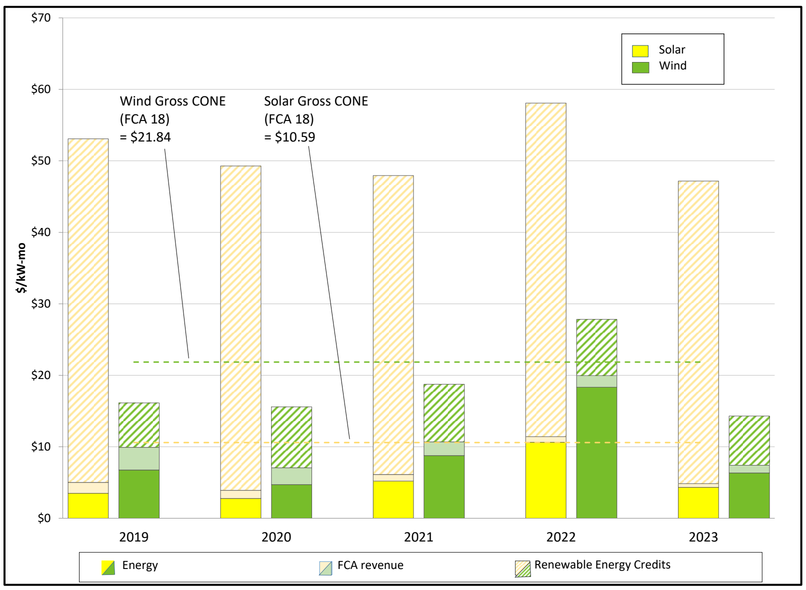
[73] These revenue components include "Pay-for-Performance" (PFP) revenue which this study does not.

[74] Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

region, analyzing how state policies and market conditions interact to affect the profitability of these renewable resources.

We assume an onshore wind unit generating power consistent with the typical profile of wind generators in New England, and a solar unit matching the profile of solar units across the region. Both units offer 53% of their generation into the day-ahead energy market at their short-run marginal costs.[75] Although solar and wind resources have approximately zero marginal costs, which would imply economic offers at $0/MWh, such resources typically have out-of-market arrangements that provide revenues when they generate energy, and thus have an incentive to offer their energy into wholesale markets at negative prices.[76] We assume that the units offer into the day-ahead and real-time energy markets at a price equal to negative one times the annual average Renewable Energy Certificates (REC) price, and clear the market whenever the LMP at the Hub exceeds their offers. The units do not provide ancillary services. The units also earn FCA revenues in proportion to the qualified capacities assumed in recent offer review trigger price (ORTP) analyses.[77] Figure 1-17 summarizes the findings.

Figure 1-17: Estimated Net Revenue for Solar- and Wind-Powered Units



The profitability of wind and solar units in the region is intricately linked with state policies, with both resource types generally relying on additional revenue streams to those in the wholesale markets to be economically viable. Between 2021 and 2023, the solar unit would have earned 80% to 90% of its revenues from the sale of renewable energy credits; similarly, 30% to 50% of the wind unit's revenue would have been attributable to RECs. While these

[75] See ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward (December 2020), p. 88, available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

[76] This analysis does not account for revenue streams from Power Purchase Agreements (PPAs), focusing instead on Renewable Energy Certificates (RECs). For each unit of energy generated in real-time in a given year, the solar unit earns the average Massachusetts Solar I REC Index price in that year, while the wind unit earns the average Massachusetts Class I REC Index price in that year.

[77] Solar and wind units earn 18.9% and 39.3% respectively of the $/kW-month FCA revenue for each kW capacity.

policies help to meet the region's clean energy targets, their economic impact on market prices and their operational strategies require careful consideration to maintain market efficiency and reliability.[78]

[78] For example, energy market prices may be distorted, with negative clearing prices prevailing whenever solar or wind units benefiting from these policies are marginal.

Section 2
Market Structure and Competitiveness Assessment

In this section, we assess the level of competition in the wholesale electricity markets. Competition ensures that the prices consumers pay and that producers receive are the result of competitive forces, and are not unduly influenced by market power. If electricity markets are unable to achieve competitive outcomes, market power mitigation controls may be necessary. The IMM performs reviews across various ISO electricity markets to identify these situations and limits their impact through the market power mitigation process.[79]

The section is structured as follows:

- Energy Market (2.1) followed by energy market mitigation (2.2),
- Forward Capacity Market (2.3) and associated mitigation (2.4),
- Financial Transmission Rights market (2.5), and
- Ancillary Services Markets, encompassing the Forward Reserve Market and the Regulation Market (2.6).

[79] Importantly, the IMM does not have defined mitigation authority for certain markets, including the regulation and Forward Reserve Markets.

2.1 Energy Market Competitiveness

A number of metrics are utilized to assess the structure and competitiveness of the energy markets; specifically:

- the high-level market concentration measures for the supply side (2.1.1) and demand side (2.1.2) of the real-time market,
- supply-side structural market power tests in the real-time market (2.1.3): pivotal supplier test (PST) and the residual supply index (RSI),
- supply offer cost mark-up metrics in the day-ahead (2.1.4) and real-time markets, and
- the level of capacity economically withheld in the real-time market (2.1.5).

Key Takeaways

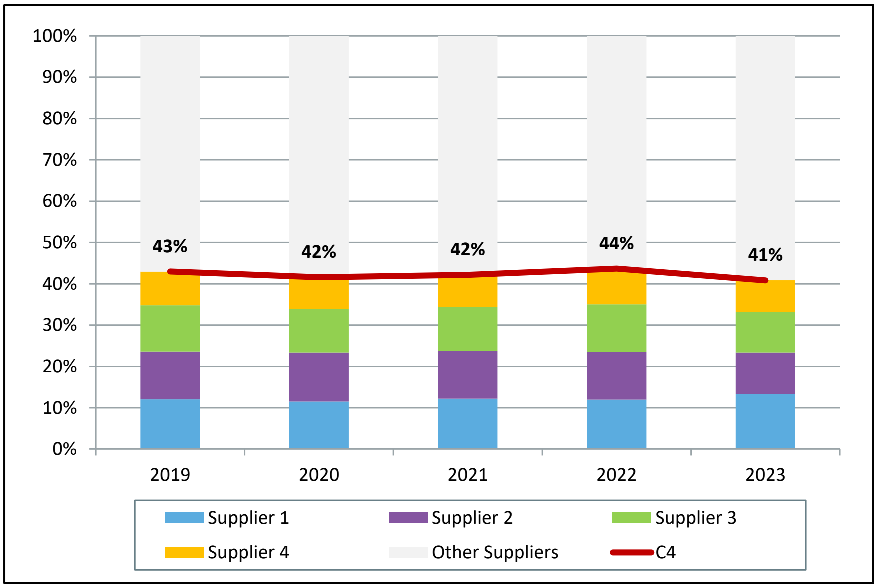
Outcomes were competitive and the exercise of market power was generally not a concern despite more instances when the market was not structurally competitive in the real-time market. The competitiveness metrics show the following:

- The share controlled by the largest 4 firms (the “C4” metric) was in line with the past five years; 41% on the supply side and 52% on the demand side in the real-time market, with shares not highly concentrated in any one firm.
- Operating reserve margins remained relatively high overall (2,768 MW above the requirement), but there were more instances of pivotal suppliers (37% vs 25% of hours in 2022) and a slight drop in the Residual Supply Index (103.5 vs 104.6 in 2022), due to generator scheduled outages (in Q4).
- Results of economic withholding analyses and metrics were in line with prior years and indicated that the:
  - impact of supply offer markups on day-ahead and real-time prices (the “price-cost mark-up” metric) was close to zero or negative; and
  - level of withheld economic capacity was relatively low (the “output gap” metric was below ~ 2%).

2.1.1 C4 Concentration Ratio for Generation

Supplier market concentration among the four largest firms controlling generation and scheduled import transactions is termed the "C4" in the real-time energy market. The measure, is useful in understanding the general trend in supply concentration as companies enter, exit, or consolidate control of supply serving the New England region over time.[80, 81] As shown in Figure 2-1 below, the C4 values have a narrow range and decreased slightly in on-peak hours in 2023.[82]

Figure 2-1: Real-time System-wide Supply Shares of the Four Largest Firms



The metric is indicative of low levels of system-wide market concentration, particularly because the market shares are not highly concentrated in any one company. In 2023, the total on-peak supply of generation and imports was about 15,230 per hour on average; about 6,226 MW per hour (41%) came from the four largest suppliers.

[80] The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in on-peak hours of the year and accounts for affiliate relationships among suppliers.

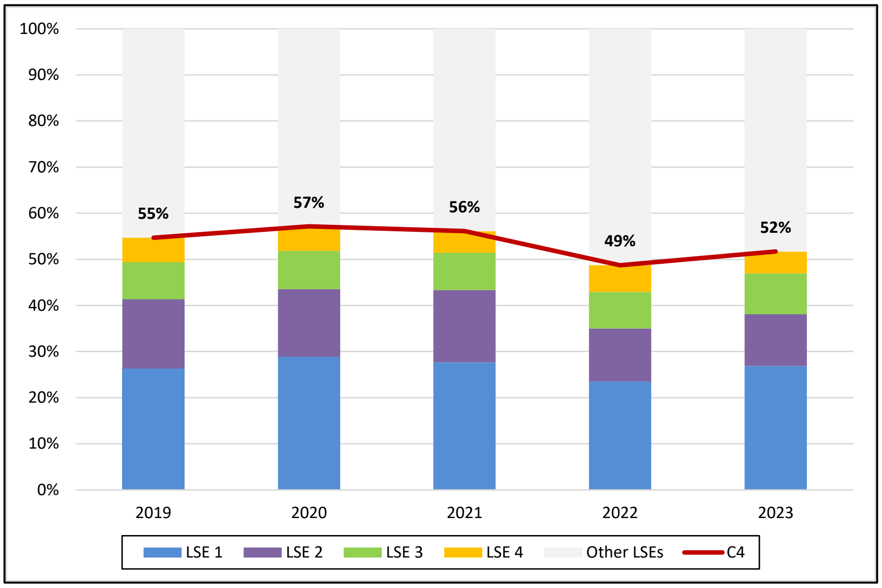
[81] The C4 analyses for both supply and demand do not account for market participants with both load and generation positions. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to raise prices to benefit their generation would come at a cost to their load position. Any actions that would suppress prices to benefit their load would come at a cost to their generation position.

[82] On-peak hours last from hour-ending (HE) 8 to HE 23 on nonholiday weekdays.

2.1.2 C4 Concentration Ratio for Load

The C4 for load measures the market concentration among the four largest load-serving entities (LSEs) in the real-time energy market, and is presented in Figure 2-2 below.[83]

Figure 2-2: Real-time System-wide Demand Shares of the Four Largest Firms[84]



In 2023, the on-peak real-time load obligation (RTLO), or the amount of electricity purchased during peak hours, averaged 15,399 MW per hour.[85] The four largest LSEs served 52% (7,958 MW) of total on-peak, real-time load obligation, up from 49% in 2022. Observed C4 values remain below five-year averages, indicating relatively low levels of system-wide market concentration.[86] Evidence does not suggest that LSEs exhibited energy market bidding behavior that would suppress prices. Over 100% of demand clears on average in the day-ahead market and the aggregate demand curve is relatively price-insensitive around expected LMPs (see Section 3.3.2 on Demand Bidding).

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[83]The C4 load metric accounts for affiliations among different LSEs and includes on-peak hours only.

[84] The firms labeled “LSE 1”, “LSE 2” and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

[85] Real-time load obligation is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between this number and the real-time generation obligation should equate to energy losses.

[86] The Load C4 ratio fell significantly in 2022 after one participant divested a large share of its generation and load into an independent company.

2.1.3 Residual Supply Index and the Pivotal Supplier Test

We apply two widely-used structural market power tests to indicate opportunities for participants to exercise market power in the real-time market: the pivotal supplier test (PST)[87] and the residual supply index (RSI).[88]

The average RSI for all five-minute real-time pricing intervals and the percentage of five-minute intervals with pivotal suppliers are presented in Table 2-1 below. Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 2-3. The figure shows the percent of hours when the RSI was above or below 100 for each year, indicating the presence of at least one pivotal supplier.

Table 2-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

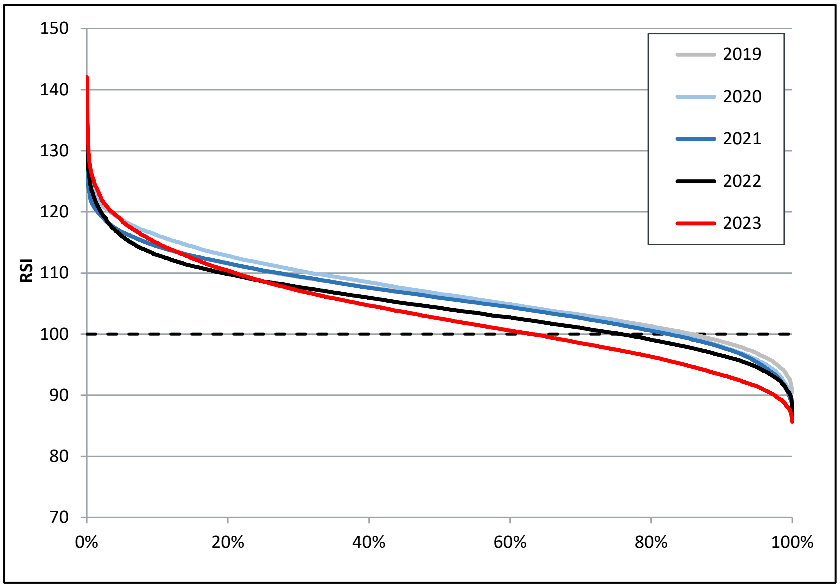
Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2019	14.7%	106.4
2020	16.6%	106.9
2021	18.0%	106.0
2022	24.9%	104.6
2023	37.3%	103.5

[87] Pivotal suppliers are identified for every five-minute pricing interval by comparing the real-time supply margin to the sum of each participant's total supply that is available within 30 minutes. When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each year to obtain the percentage of intervals with pivotal suppliers.

[88] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier is needed to meet demand, and could potentially exercise market power (if permitted). Further, if the RSI is less than 100, there is at least one pivotal supplier. Conversely, when the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market. The data used to calculate the RSI come from the ISO's real-time market software (the Unit Dispatch System, or UDS). Based on these data, the RSI for an interval *t* is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

Figure 2-3: System-wide Residual Supply Index Duration Curves



There were more five-minute intervals with pivotal suppliers in 2023 than in any other year in the reporting period. This indicates that suppliers faced relatively less competition in 2023 than during the four previous years. The increase in the number of intervals with at least one pivotal supplier was driven by lower reserve margins, particularly during Q4 2023. If we exclude Q4 from the calculation, the pivotal supplier frequency is almost identical to that of 2022. The RSI was above 100 in 63% of real-time pricing intervals in 2023, which was lower than the 2022 result (75%). Of the lowest 25% of hourly RSI values in 2023, more than half occurred during Q4.

Reserve margins have fluctuated throughout the reporting period for several reasons, including generator outages, resource additions or retirements, and changes in the reserve requirement. When reserve margins (i.e., surplus available supply) are lower, there is an increased likelihood that the largest supplier is needed to meet load and the reserve requirement. The average margin for the total reserve requirement was 2,768 MW in 2023, down 120 MW from 2022 and the lowest value of the reporting period. During Q4, the average margin for the total reserve requirement was just 1,959 MW, significantly lower than in the other quarters. This was due to multiple long-term planned outages at pumped-storage facilities, which typically provide large volumes of reserves.

2.1.4 Day-Ahead and Real-Time Price-Cost Markups

In a perfectly competitive market, all market participants' energy supply offers would equal their marginal costs. The energy component of the LMP would then be set by the supply offer or demand bid on the margin. However, in practice, participants can raise their supply offers above marginal costs. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitment decisions, leading to inefficient market outcomes. Though the IMM administers mitigation rules in the energy market to prevent the exercise of market power, participants are allowed to increase their offers within a certain threshold before mitigation is applied.

The price-cost markup estimates the divergence of the observed market outcomes from the ideal scenario in which all energy supply is offered at marginal cost. The results provide insight on how uncompetitive offer behavior affects the energy markets. A larger price-cost markup means that a larger component of the LMP is the result of inflated supply offers. This analysis used different methods for the day-ahead and real-time price cost markup calculations. For the day-ahead metric, IMM simulated the market clearing using supply offer and marginal cost scenarios.[89] [90] The real-time analysis calculated (load-weighted) LMPs by creating supply curves for 1) available generation[91] by offer price and 2) available generation by marginal cost estimate, and then intersecting real-time demand with each.

The annual price-cost markup values from the day-ahead simulation and real-time analysis are shown in Table 2-2 below.

Table 2-2: Energy Market Price-Cost Markup, %

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2019	-2.4%	-7.4%
2020	0.9%	-3.1%
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%

In 2023, the price-cost markup for the day-ahead energy market remained low at -2.2%. This indicates that the average marginal resource offered below its marginal costs, and that offers deviating from marginal cost decreased the generation-weighted day-ahead energy market price by approximately 2.2%. This result is similar to that of prior years, and is consistent with normal year-to-year variation given modeling and estimation error.[92] In the real-time market, annual load-weighted markups were also close to zero or negative during all years of the reporting period. These results indicates that competition among suppliers in the day-ahead

[89] To calculate the day-ahead price-cost markup, the IMM used the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model to simulate the day-ahead market clearing using two scenarios: The offer case uses actual day-ahead energy market supply offers submitted by market participants. The marginal cost case assumes all market participants offered at an estimate of their short-run marginal cost. The price-cost markup is then calculated as the percentage difference between the annual generation-weighted LMPs for the offer case and the marginal cost case simulations.

[90] Prior to the 2022 Annual Markets Report, this metric used a different methodology to estimate marginal costs. This is why the values in this report are lower than values for the same years in previous reports.

[91] Available generation is equal to on-line generation plus generation capacity that can come on-line within 30 minutes. It comes from on-line generators (both long lead-time and fast-start) and off-line fast-start generators.

[92] Note that the IMM's estimates of marginal cost are an approximation of actual marginal costs, and the simulations used to calculate the price-cost markup are subject to modeling differences when compared to the market model the ISO runs for the day-ahead market.

and real-time markets limited their ability to inflate LMPs by submitting offers above marginal cost.[93]

In this assessment, we reviewed day-ahead price-cost markup values at an hourly level and compared the peak load hour price-cost markup with the forecasted supply margin at peak. Comparing these attributes provides insight into whether participants take advantage of tight system conditions, when market power tends to be more of a concern, by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2023, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present.

Gas-fired generator offer behavior had the largest impact on annual markup values in both markets. Gas-fired generators may offer at values lower than their estimated marginal costs for multiple reasons, including managing gas burn to nominations or offering lower output levels below their fuel price adjusted reference level.[94] Renewable generator offer behavior also tends to reduce markups, but to a lesser extent. Though it is common for renewable generators to offer below marginal cost, these generators are typically smaller and/or export-constrained.

2.1.5 Real-Time Economic Withholding

Economic withholding prevents some generation that would otherwise be economic from clearing, which in turn raises the market price. The capacity that does not clear as result of suppliers offering above cost is quantified using an output gap metric.[95]

Hourly economic withholding (as a percent of capacity) during on-peak hours in each of the past five years is summarized in Figure 2-4 below. Note the curves depict the distribution of hourly withholding, where the widest sections of each curve represent the most-frequently observed levels of withholding. Results are broken down for two groups: combined withholding by the top four generating companies (those with the largest share of generation) versus all others.

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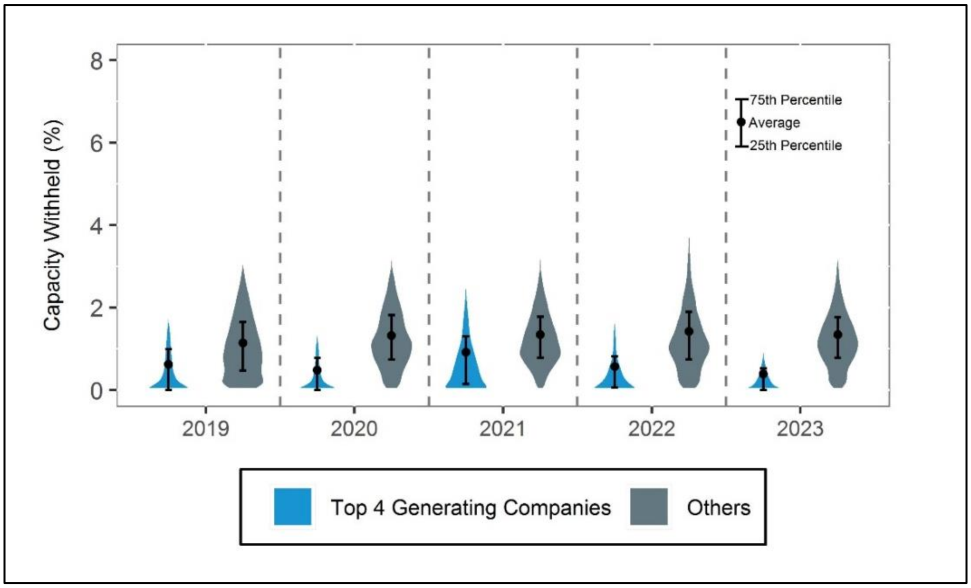
[93] Differences between the real-time and day-ahead price-cost markups values are due to several factors, including: 1) differences in the methodologies used to calculate the price-cost markup in each respective market; 2) modeling differences between the day-ahead and real-time energy markets; and 3) real-time events that the day-ahead market did not anticipate.

[94] The most extreme negative markup values occurred during the winter months, when generators are more likely to have fuel price adjustments (FPAs) in place. FPAs are applied to the entire output curve and replace the default gas index value, but gas-fired generators often use FPAs to reflect the price of incremental gas needed at higher output levels, which might be higher than the market value of liquidating gas that they have already purchased.

[95] We estimate the economically withheld capacity for each generator in every real-time interval as the difference between: a) the quantity that was economic (i.e., the sum of MWs where marginal cost ≤ LMP) and, b) the actual quantity offered (i.e., the sum of MWs where offer price ≤ LMP). In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers only non-fast-start generators that are online and all fast-start generators (online or offline), and it does not assess potential withholding by offline, non-fast-start generators.

Figure 2-4: Hourly Real-time Economic Withholding During On-Peak Hours



In 2023, economic withholding was relatively low across both groups (generally below 2%) and generally in line with levels seen in past years. Although not presented in the figure, levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers were largely unable or did not attempt to take advantage of tight system conditions by economically withholding.

2.2 Energy Market Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[96] Under certain conditions, the IMM will mitigate generator supply offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values.[97]

Here, we review the level and underlying drivers of the various forms of energy market mitigation in the day-ahead and real-time energy markets.

Key Takeaways

Supply offer mitigation remained low, and saw a reduction on prior years, at just 460 asset hours of mitigation, compared to 1.4 million asset hours subject to potential mitigation. This outcome is consistent with the system-level competitiveness metrics above, as well as there being few instances of localized market power (import constrained areas or local reliability commitments).

We continue to emphasize the importance of reviewing and improving mitigation rules to ensure their robustness under changing competitive conditions. To that end we have issued a number of recommendations in prior reports, which can be categorized as follows:

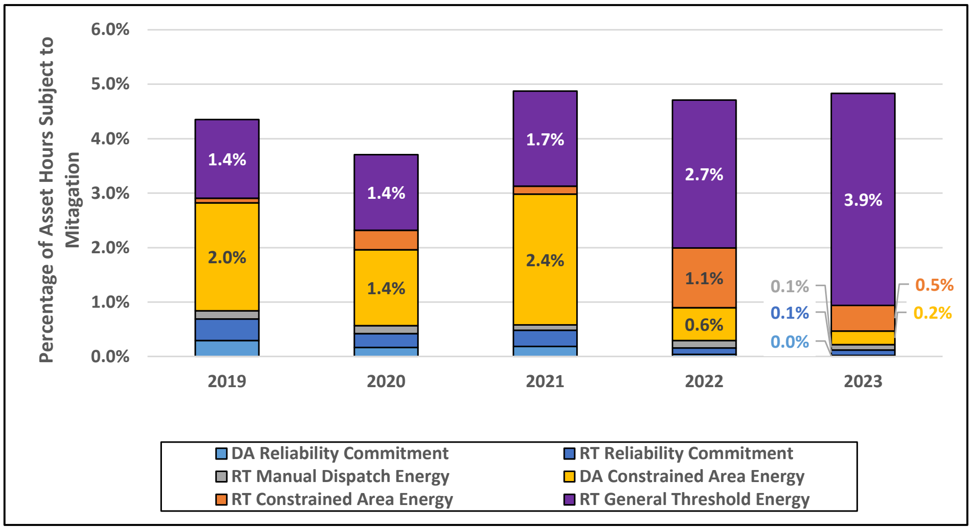
- Review of conduct and impact tests and thresholds, and the day-ahead mitigation exemption for non-capacity resources.
- Improved indicators of structural market power at a system level (accounting for company affiliations, generator ramping) as well as for local market power (export-constrained areas).
- Improvements to the accuracy of reference level calculations, such as prioritizing reliance on cost-based reference levels. We also support the ISO's current proposal to introduce MW-dependent Fuel Price Adjustments, which will reflect that natural gas costs can vary by quantity.

[96] This review of supply offers is automated (along with the offer mitigation process), and occurs within the ISO's energy market software.

[97] The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs. Seven mitigation types utilize mitigation tests and are used in ex-ante supply offer mitigation. An eighth mitigation type for dual-fuel generators is performed after-the-fact, when a dual-fuel generator burns a low-priced fuel but submits supply offers based on a higher-cost fuel.

A structural test failure serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours with a structural test failure from 2019 to 2023 is shown below in Figure 2-5.[98]

Figure 2-5: Energy Market Mitigation Structural Test Failures



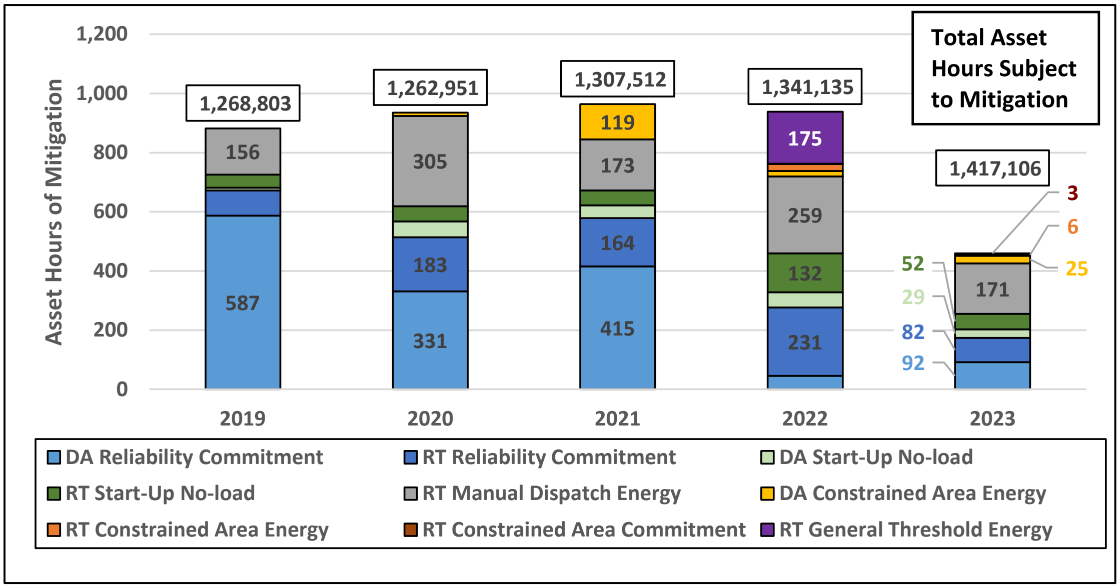
In 2023, the total asset hours subject to mitigation reached 1.4 million asset hours, in which approximately 68,000 asset hours (4.8%) failed structural tests.[99] The structural test for general threshold energy mitigation fails the most often and triggers any time a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 2-6 along with the total amount of asset hours subject to mitigation (white boxes).

[98] A structural test failure depends on the type of mitigation analyzed. The definitions of the structural test applied in general threshold and constrained area mitigation can be found in *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.2, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. The conditions to pursue manual dispatch energy and reliability commitment mitigation are found in Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

[99] The asset hours subject to mitigation are estimated as a committed generator with an economic dispatchable range at or above its economic minimum (eco min). Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

Figure 2-6: Energy Market Mitigation Asset Hours



Total mitigation asset hours significantly decreased from 938 hours in 2022 to 460 hours in 2023. Day-ahead reliability commitment mitigation occurred more frequently in 2023 with 92 asset hours of mitigation sourcing from reliability commitments in Southeastern Massachusetts (62 asset hours), Rhode Island (16 asset hours), and Maine (14 asset hours). Manual dispatch energy (MDE) mitigation occurred the most frequently of all mitigation types in 2023 as the conduct test threshold for MDE mitigation is relatively tight, only allowing manual dispatch offers to be 10% higher than reference levels.[100]

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.[101] In 2023, reliability commitments reached 316 asset hours in the day-ahead and 1,365 asset hours in the real-time markets, in which the majority of asset hours (144 in day ahead, 1,110 in real time) occurred in the Southeastern Massachusetts load zone. Reliability commitment mitigations reached 174 asset hours in 2023, or 10% of reliability commitment asset hours.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[102] SUNL mitigations occur very infrequently and may reflect a participant's

[100] For more information on Energy Market Mitigation types and thresholds, see *An Overview of New England's Wholesale Electricity Markets: A Market Primer* (June 2023), Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

[101] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. See *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[102] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters).

failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In 2023, only six participants were associated with the 81 asset hours of SUNL commitment mitigation.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. In 2023, structural test failures totaled 10,251 asset hours, in which transmission constraints in Connecticut accounted for nearly half of all structural test failures at 4,748 asset hours. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. Over the five-year reporting period, mitigation has occurred for only 174 asset hours in the day-ahead energy market and only 34 asset hours occurred in the real-time energy market.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs with the least frequency of all mitigation types. Across the reporting period, over 30,000 asset hours of pivotal supplier energy was subject to mitigation each year on average; mitigation has occurred for only 175 asset hours, all in 2022. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with five participants accounting for 83% of the structural test failures over the review period.

Manual dispatch energy (MDE) mitigation: The ISO will assign manual dispatch points to utilize flexible generation in addressing short-term issues on the transmission grid. As a result, gas or dual-fuel generators receive manual dispatches most often, accounting for 92% of the 1,387 asset hours of manual dispatch in 2023. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than any other mitigation type, reaching a total of 171 asset hours in 2023.

We continue to emphasize the importance of reviewing and improving mitigation rules to ensure their robustness under changing competitive conditions. To that end we have issued a number of recommendations in prior reports, which are summarized in the Executive Summary and can be categorized as follows:

- Review of conduct and impact tests and thresholds, and the day-ahead mitigation exemption for non-capacity resources.

- Improved indicators of structural market power at a system level (accounting for company affiliations, generator ramping) as well as for local market power (export-constrained areas).

- Improvements to the accuracy of reference level calculations, such as prioritizing reliance on cost-based reference levels. We also support the ISO's current proposal to introduce MW-dependent Fuel Price Adjustments, which will reflect that natural gas costs can vary by quantity.

2.3 Forward Capacity Market

Below, we review the structural competitiveness of the Forward Capacity Market (FCM) using the Residual Supply Index (RSI) and Pivotal Supplier Test (PST).

> ***Key Takeaways***
>
> The capacity market has been structurally competitive in recent auctions, as indicated by pivotal supplier test and RSI metrics. In FCA 18, a supplier needed a portfolio of over 3,300 MW to be pivotal, and the largest portfolio in FCA 18 with less than 3,100 MW.
>
> While there were pivotal suppliers in the Southeastern New England (SENE) import-constrained zone in prior auctions, in the two most recent auctions the zone was not separately modelled due to the increase in the import capability limit into the zone and a decrease in the zonal load forecast, thereby improving competitiveness.

Similar to the PST and RSI calculated for the energy market, we account for affiliations between suppliers to reflect all capacity under a supplier's control.[103,104] For each Forward Capacity Auction (FCA), we consider the qualified capacity of existing resources prior to the auction given the difficultly of predicting intra-auction new supply behavior. Both metrics are calculated for the import-constrained zone (Southeastern New England or SENE), in addition to the larger system.

For the purposes of market power mitigation, de-list bids from a pivotal supplier above the dynamic de-list bid threshold may be subject to mitigation.[105] This process ensures that suppliers do not withdraw capacity from the auction at uncompetitive prices to raise the FCA clearing price in a way that may benefit the remainder of their portfolio.

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[103] See *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.23.4, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. As defined in that section, for the purposes of this test, "the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)."

[104] The PST the RSI rely on the following inputs:

•Capacity requirements – both at the system level (Net Installed Capacity requirement, or Net ICR) and the import-constrained area level (Local Sourcing Requirement, or LSR). The Net ICR and LSR change from year to year.

•Capacity zone modelling – different capacity zones are modelled for different FCAs depending on the quantity of capacity in the zone and transmission constraints.

•The total quantity of existing capacity – a value driven by retirements from existing resources and additions from new resources (which become existing resources in subsequent years.

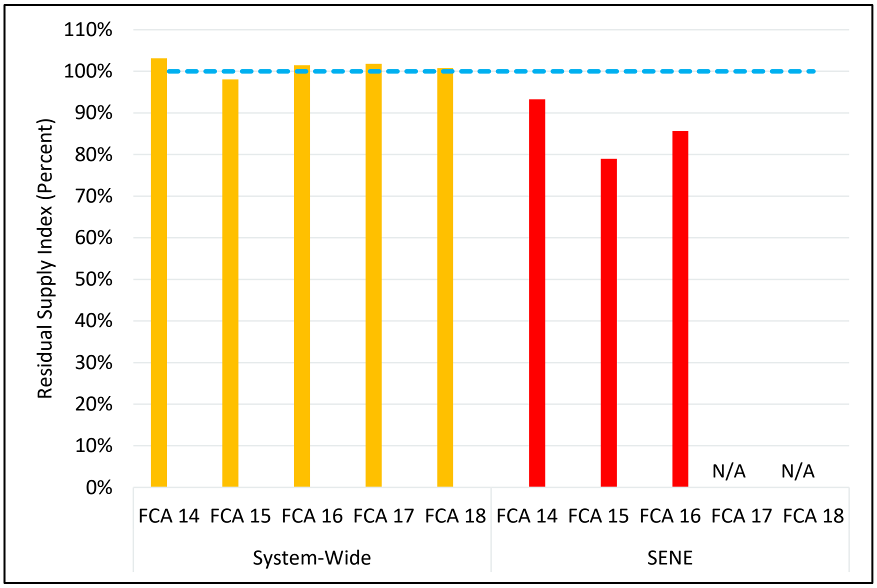
•Supplier-specific portfolios of existing capacity – values that can change year-over-year as a result of mergers, acquisitions, divestitures, affiliations, resource performance, etc. To avoid providing supplier-specific data, these are not described in any detail in this document, but should be taken into account when considering the analysis.

[105] Note that there are certain conditions under which capacity is treated as non-pivotal. For more on these conditions, see *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.23, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

Residual Supply Index Results

The RSIs for the system and for each import-constrained zone over the past five FCAs are shown in Figure 2-7 below.

Figure 2-7: Capacity Market Residual Supply Index, by FCA and Zone



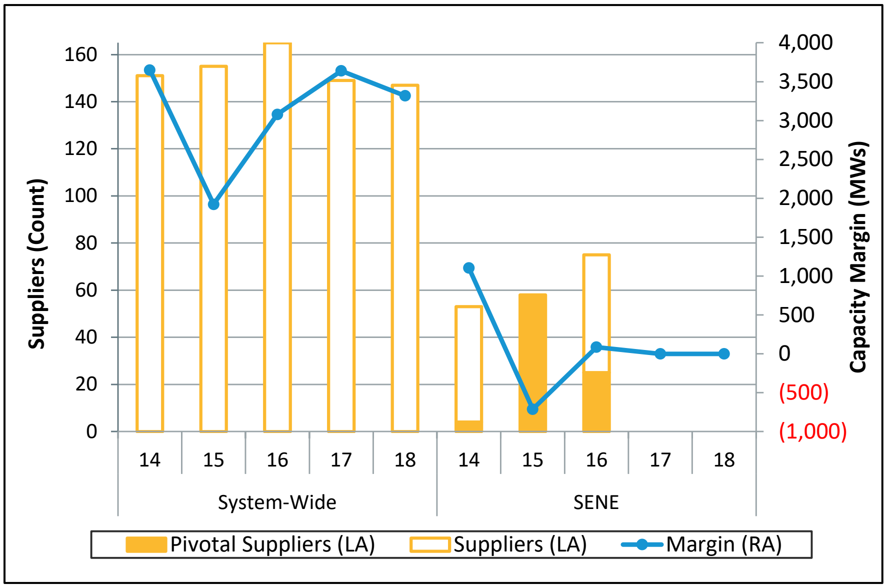
The primary takeaways from FCA 18 were: 1) the system-wide RSI was above 100% for the third auction in a row; and 2) the SENE zone was not modelled.

The RSI in FCA 17 was 102%, which indicates that Net Installed Capacity requirement (Net ICR) could still be satisfied without the largest supplier and no suppliers were pivotal at the system level. There were no zonal RSI values (red) in FCA 18. The Southeastern New England zone was removed in FCA 17 due to a decrease in the zonal load forecast and an increase in the import capability limit into the zone.

Pivotal Supplier Test Results

The number of suppliers and pivotal suppliers within each zone over the past five FCAs are presented in Figure 2-8 below. To provide additional insight into the approximate portfolio size needed to be pivotal, the figure also presents the margin by which capacity exceeded or fell below the relevant capacity requirement. For example, consider the SENE capacity zone in FCA 14. The amount of existing capacity exceeded the local sourcing requirement (LSR), resulting in a capacity margin of 1,105 MW (right axis – blue marker). Consequently, only suppliers with a portfolio greater than 1,105 MW in this zone were pivotal in FCA 14. Of the 53 suppliers in SENE in FCA 14 (left axis – yellow bar), only four (highlighted in yellow) were pivotal.

Figure 2-8: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



At the system level, the capacity margin remained high over the past five FCAs with no pivotal suppliers present. In FCA 18, a supplier needed a portfolio of over 3,300 MW to be pivotal, and the largest portfolio entered FCA 18 with less than 3,100 MW. In addition to no pivotal suppliers at the system level, the SENE capacity zone did not need to be modelled in FCA 18 as an import-constrained zone, which improved the overall structural competitiveness of the FCM.

2.4 Forward Capacity Market Mitigation

In this section, we provide a summary of the mitigation measures employed in the FCM between FCA 14 and FCA 18. The first subsection 2.4.1 looks at supplier-side mitigation for existing resources. The second subsection 2.4.2 covers buyer-side mitigation, namely the Minimum Offer Price Rules (MOPR) for new resources.[106]

Key Takeaways

Seller- and buyer-side costs reviews and instances where mitigation was applied remained low in FCA 18. All 2,400 MW of de-listed, existing resources exited the auction through accepted retirement bids or dynamic de-list bids priced below the mitigation threshold (the Dynamic De-list Bid Threshold).

FCA 18 was the last auction in which the Minimum Offer Price Rule and a limited Renewable Technology Resource (RTR) exemption applied. Buyer-side mitigation was also low due to the RTR exemption, low Offer Review Triggers Prices and limited new entry of non-sponsored policy resources.

[106] For more information on changes to the MOPR rule, see Section 9.

2.4.1 Supplier-Side Market Power

The IMM reviews certain de-list bids to determine if they are consistent with a resource's avoidable costs of a capacity supply obligation (CSO); i.e., its net going forward operating and capital costs, including expected capacity performance payments, risk premium, and opportunity costs. While there are a variety of de-list bid types, only a few require review by the IMM prior to the auction, including general static de-list bids, import and export bids, retirement de-list bids and permanent de-list bids.[107]

Retirement and permanent de-list bids

Retirements and permanent de-list bids are removed from the capacity market – permanently – when the FCA clearing price falls below the bid value. All bids for capacity exceeding 20 MW are subject to an IMM cost review and potential mitigation. In FCA 18, fourteen resources retired over 870 MW of capacity. Of the three retired resources above 20 MW, only one resource had their bid mitigated, but the participant elected to unconditionally retire the resource regardless of auction outcomes.

Static de-list bids

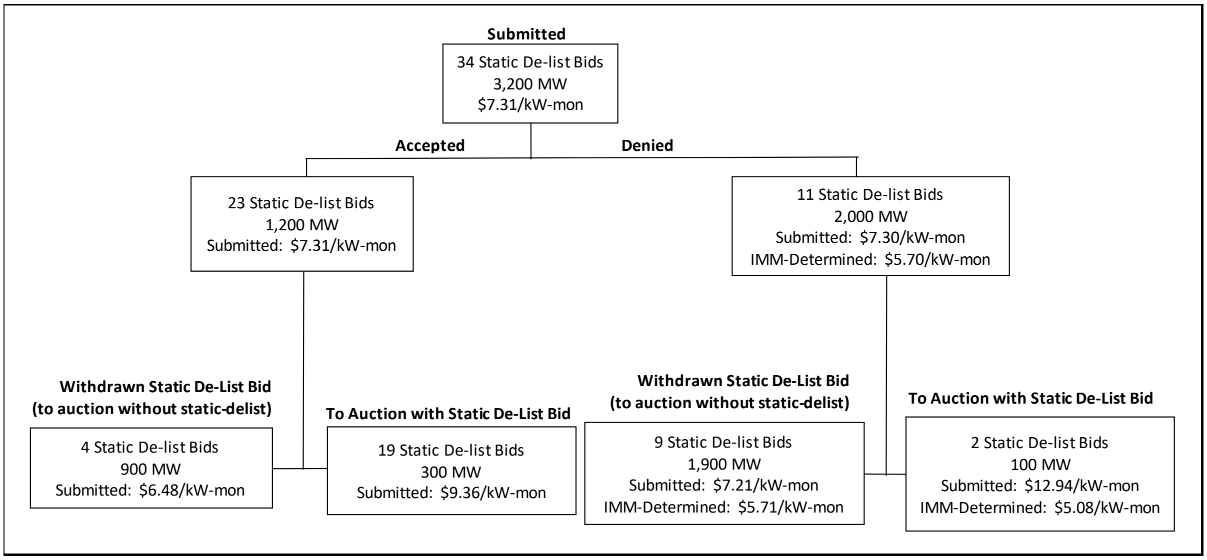
The IMM reviews all static de-list bids during the FCA qualification process, and issues a determination denying or accepting the bid value. Participants can take various actions after the IMM determination, including accepting the bid price, reducing or withdrawing the bid. Ultimately, only denied bids of pivotal suppliers are mitigated; the pivotal supplier test is performed closer to the auction date.

Summary statistics for static de-list bids from FCA 14 through FCA 18 as well as the path the bids took from the time of initial submittal to the auction are provided in Figure 2-9 below. Note that all de-list bid prices are megawatt-weighted averages.[108]

[107] The term "general" is used to differentiate between other types of static de-list bids, including ambient air static de-list bids and ISO low winter static de-list bids, which are not subject to IMM review.

[108] Price calculations are not presented for new import capacity resources because, depending on the circumstances, the direction of the price difference can vary for price-quantity pairs within the same supply offer. Consequently, the resulting price difference summary statistics are less meaningful.

Figure 2-9: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCAs 14 – 18)[109]



For FCAs 14 through FCA 18, the IMM reviewed 34 general static de-list bids from nine different lead participants, totaling roughly 3,200 MW of capacity.[110] The IMM denied 11 of the reviewed bids accounting for 61% of static de-list capacity, generally finding that the submitted bids were either inconsistent with the resource's net going forward costs or were not sufficiently supported.[111] For resources that were denied and went to the auction (box furthest to the right, third level), the weighted-average price of denied static de-list bids was $7.86/kW-month less than the market participant's originally submitted price. Only de-list bids belonging to pivotal suppliers are mitigated, but there were no pivotal suppliers in FCA 18. Therefore, no de-list bids were mitigated down to the IMM-determined de-list bid price.

2.4.2 Buyer-side Market Power (Minimum Offer Price Rule)

Summary statistics for resources requesting to offer below their respective offer review trigger price (ORTP) in FCAs 14 through 18 are provided in Figure 2-10 below.[112] Note that all offer prices are megawatt-weighted averages.

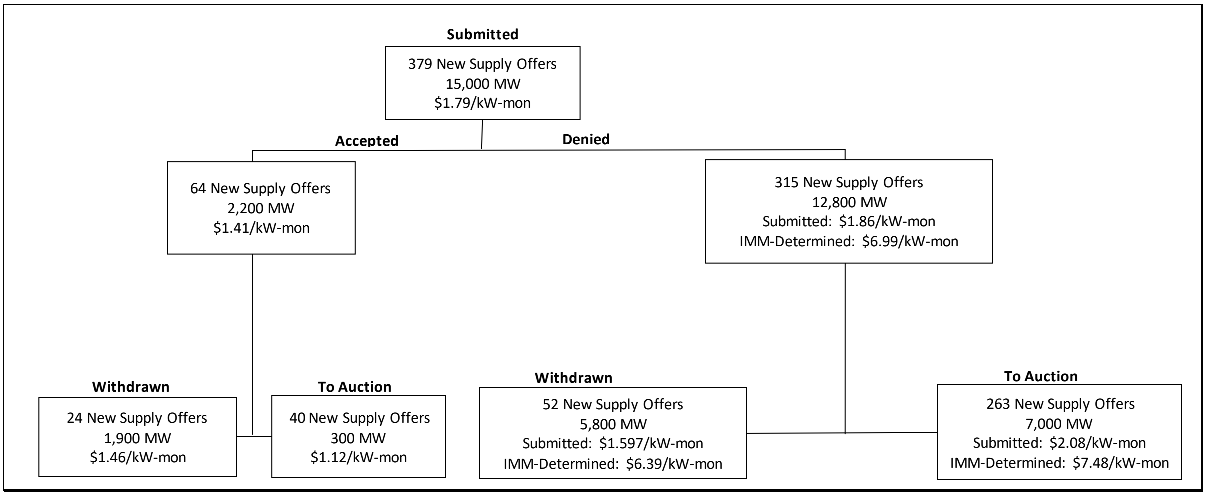
[109] All MW values are rounded to the nearest hundred.

[110] A resource with a static de-list bid in each of the three auctions would be counted three times in the MW total; however, the associated lead participant is only counted once.

[111] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted bid is entered. The mitigation only takes effect if the supplier is deemed pivotal, an evaluation that is done some months after the cost review process in completed.

[112] All MW values are rounded to the nearest hundred.

Figure 2-10: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCAs 14 – 18)



For FCAs 14 through 18, the IMM reviewed 379 new supply offers from 52 different participants requesting to offer below the ORTP.[113] The IMM denied 315 new supply offers accounting for 85% of all new capacity reviewed.[114] For resources that were denied and entered the auction (box furthest to the right, third level), the weighted average price of denied new supply bids was $5.40/kW-month higher than the participant's originally submitted price.

In FCA 18, some new resources elected to enter the auction through the renewable technology resource (RTR) exemption. Three resources qualified and entered FCA 18 through the RTR exemption, utilizing roughly 200 MW of the 592 MW allowance.[115]

2.5 Financial Transmission Rights Market

In this section, we look at the concentration of Financial Transmission Rights (FTRs). In this context, market concentration refers to the extent to which FTR MWs are concentrated among market participants.

Key Takeaways

Ownership of FTR paths continued to be relatively concentrated in 2023, with the top four participants holding over 60% of FTR capacity, and the number of unique participants ranging between 34-45 participants over the past five years. However, overall profit levels in the FTR market remained low, and in fact in 2023 there was a collective loss of $14.1 million.

[113] Note that this total does not include supply offers from new import capacity resources without transmission investments, which are discussed in the supplier-side market power section.

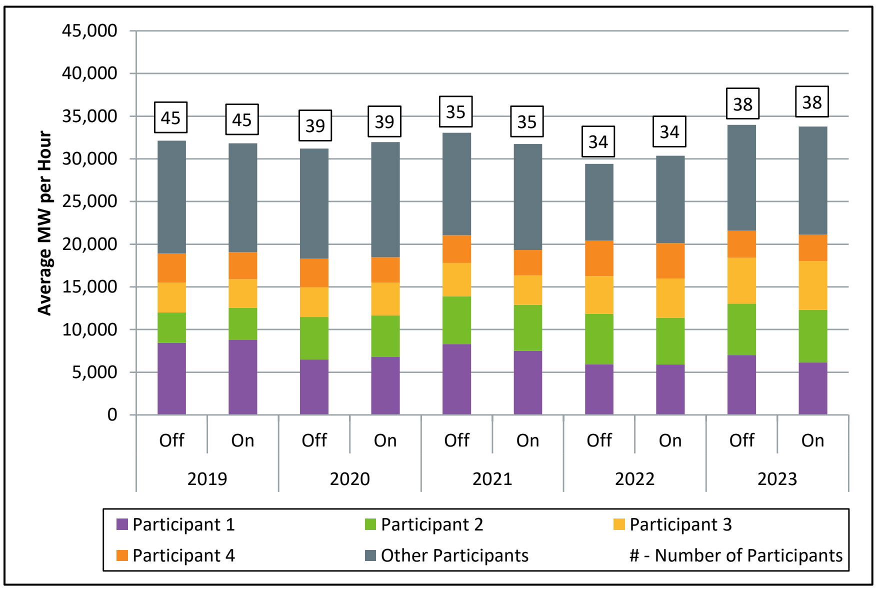
[114] A resource with a new supply offer in each of the three auctions would be counted three times in the MW total. In addition, where FCA qualified capacity does not exist for a resource (e.g., the proposal was withdrawn or denied), the summer capacity from the resource's show-of-interest is used instead. Consequently, the presented total overstates the actual capacity.

[115] For more information on historical RTR exemption allowances, see the ISO's *Forward Capacity Market Parameters* spreadsheet (March 31, 2023), available at https://www.iso-ne.com/static-assets/documents/2015/09/fca_parameters_final_table.xlsx.

Anticipating what a competitive level of FTR ownership looks like is complex as it is unlikely to match system-level load-serving or generation ownership percentages. This is because there are not clear commercial reasons for all market participants to hold FTR positions (e.g., participants that serve load or own generation in unconstrained areas). Even those participants that could benefit may have risk preferences that favor exposure to day-ahead congestion over managing that exposure with the purchase of a financial instrument. Further, FTR market design permits the purchase of FTRs for financial speculation, so many FTR holders have no load or generation position at all.

The concentration of FTR MWs among market participants in 2023 was similar to prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each year is shown in Figure 2-11 below.[116] This figure also shows the number of different participants that held FTRs each year (indicated by the number above each stacked column). This information is broken down separately for the on-peak and off-peak periods.

Figure 2-11: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



The top four participants held 63% of on-peak FTR MWs and 64% of off-peak FTR MWs in 2023. The concentration ratio of the top four FTR holders has stayed relatively stable over the reporting period, ranging between 58%-69%. However, the percentage of FTRs held by the largest FTR holder has trended downward over the reporting period. The largest FTR holder held 28% of on-peak FTR MWs and 26% of off-peak FTR MWs in 2019, but held only 18% and 21% of on-peak and off-peak FTR MWs in 2023. Meanwhile, the total number of unique FTR holders rose in 2023 with 38 unique participants in both the on-peak and off-peak periods. Over the last five years, the number of unique participants has ranged between 34-45 participants.

[116] The firms labeled "Participant 1," "Participant 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

2.6 Ancillary Services

Below, we review the competitiveness of the Forward Reserve Market (FRM) auctions and the Regulation market. The first subsection (2.6.1) provides RSI results for the last 10 FRM auctions. The second subsection (2.6.2) reviews available regulation capacity relative to the regulation requirement and indicates the RSI for 2023.

> ***Key Takeaways***
>
> The competitiveness assessment of the Regulation and Forward Reserve Markets (FRM) paints contrasting pictures.
>
> The regulation market continues to be structurally competitive, with available supply significantly exceeding the regulation requirement, with no supplier controlling enough supply to potentially have market power.
>
> The majority of recent FRM auctions were structurally uncompetitive for both ten-minute and thirty-minute offline reserves. While the FRM is soon to be sun-set with the implementation of the Day-Ahead Ancillary Services Initiative (DASI), the consistent lack of structural competitiveness along with elevated offers and clearing prices led us to recommend a review and update of the offer cap and offer publication policy in our Spring 2023 quarterly report. The ISO acted upon the recommendation with proposed Tariff changes, which were recently approved by FERC.[117]

2.6.1 Forward Reserve Market

The competitiveness of the FRM is assessed using the Residual Supply Index (RSI) and is based on FRM offer quantities by participant and the forward reserve requirements in each auction. The heat map provided in Table 2-3 below shows the offer RSI for the TMNSR requirement and the "total thirty-minute" reserve requirement at the system level.[118,119]

[117] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap ER24-1245-000* (April 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf

[118] The "total thirty-minute" reserve requirement considered in this section is the sum of the TMNSR and TMOR FRM requirements as discussed in Section 7. The RSI for TMNSR is based on the total quantity of TMNSR offers, excluding the largest TMNSR offer quantity by a single market participant. The RSI for the total thirty-minute requirement is computed similarly. Given that TMNSR can also satisfy the total thirty-minute requirement, the TMNSR offer quantity and the TMOR offer quantity are combined to determine this value.

[119] No zonal values are shown as there were no zonal reserve requirements during the reporting period.

Table 2-3: Offer RSI in the FRM for the TMNSR and the Total Thirty-Minute Requirements[120]

Procurement Period	TMNSR (System)	Total Thirty-Minute (System)
Summer 2019	90	97
Winter 2019-20	120	118
Summer 2020	84	97
Winter 2020-21	102	115
Summer 2021	92	108
Winter 2021-22	110	116
Summer 2022	78	90
Winter 2022-23	109	112
Summer 2023	81	86
Winter 2023-24	82	88

Structural market power has been observed in many of the recent FRM auctions. This trend has been especially pronounced for the summer procurement periods; each of the last five summer TMNSR RSI values and four of the last five summer total thirty-minute RSI values have been below structurally-competitive levels.[121] Additionally, structurally-uncompetitive levels were observed for both FRM requirements in the most recent winter auction. The lack of competition at the structural level was one of several factors that led the IMM to recommend that the forward reserve offer cap price be reviewed and updated.[122] This Tariff-specified cap is the only constraint for potentially uncompetitive supply offers in forward reserve auctions, as the IMM does not have the authority to perform cost-based reviews nor to mitigate uncompetitive offers.

2.6.2 Regulation Market

We reviewed the competitiveness of the regulation market by examining market structure and resource abundance. The abundance of regulation resources and the relatively unconcentrated control of that supply implies that market participants had little opportunity to engage in economic or physical withholding in 2023. For these reasons, we find that the regulation market was competitive in 2023. Figure 2-12 below indicates the regulation requirement relative to available supply.

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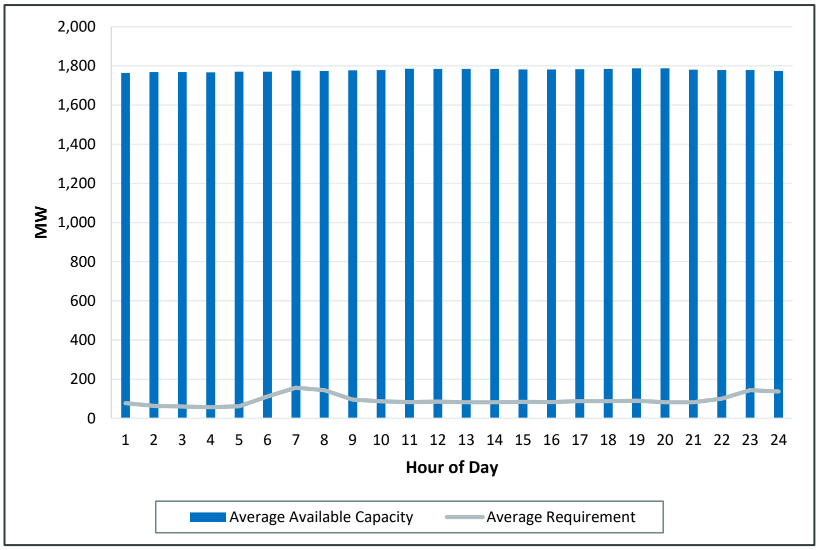
[120] The colors indicate the degree to which structural market power was present; red is associated with low RSIs, white with moderate RSIs, and green with high RSIs. Dark red indicates that structural market power was present, while dark green indicates that there was ample offered supply without the largest supplier.

[121] As mentioned in Section 2.1.3, RSI values below 100 indicate that the reserve requirement could not be satisfied without the offers from the largest supplier, and, consequently, that that supplier could potentially exercise market power (if permitted).

[122] For our recommendation related to the forward reserve offer cap, see our *Spring 2023 Quarterly Markets Report* (August 1, 2023), pp 47-51, available at https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

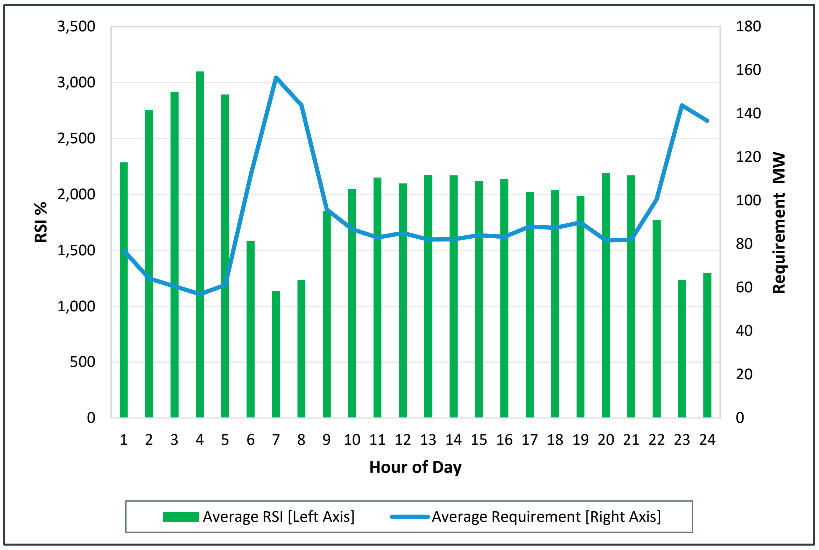
Figure 2-12: Average Regulation Market Requirement and Available Capacity, 2023



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an abundance of available supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The RSI provides a better indicator of the structural competitiveness of the regulation market. As shown in Figure 2-13, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 2-13: Average Regulation Requirement and Residual Supply Index



In 2023, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system had the capability to serve ten times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirements.

Section 3
Day-Ahead and Real-Time Energy Market

We examine key trends and drivers of energy market outcomes in this section, which is structured as follows:

- Day-ahead and real-time energy prices across a number of dimensions, including location, time-of-day, and convergence (3.1)
- Factors that influence supply and demand participation (3.2 & 3.3)
- Energy markets and system reliability interactions (3.4)
- Net commitment period compensation (NCPC) payments (3.5)
- Summary of system events in 2023 (3.6)[123]
- Demand response resource (DRR) participation in the energy markets (3.7)

Day-ahead and real-time energy prices decreased significantly from 2022 levels. This reflects a large decrease in underlying fuel prices, most notably natural gas. The average Hub price was $36.82/MWh in the day-ahead market, down 57% from $85.56/MWh in 2022. A decrease of similar magnitude occurred in the real-time market, which saw an average Hub price of $35.70/MWh in 2023. These decreases are consistent with lower natural gas prices in 2023, which fell by 67% relative to 2022.

In addition to generation costs, other factors played roles in determining the energy market outcomes in 2023. Noteworthy system events included a deficiency of operating reserves on July 5, 2023, which produced high energy and reserve prices and a 30-minute capacity scarcity condition. Transmission congestion and out-of-market actions taken to maintain system reliability only slightly impacted energy market outcomes in 2023, as incidence of both were relatively low. DRRs continued to be infrequently dispatched in 2023, because of high offer prices.

NCPC payments totaled $34.4 million in 2023, a decrease of $18.7 million (35%) compared to 2022. NCPC payments as a percentage of total energy payments remained low, and increased slightly from 0.5% in 2022 to 0.7% in 2023. This percentage increase was driven, in part, by commitment out-of-merit payments in late 2023, when costly fast-start oil-fired generators were frequently committed due to tight system conditions but did not set price. An outage taken by a large flexible generator during this period led to an increased frequency of these commitments.

[123] For a detailed assessment of system events, see our *Quarterly Markets Reports*, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor

3.1 Energy Prices

Below, we evaluate and discuss energy prices across a number of dimensions, including by energy market (i.e., day-ahead and real-time), time-of-day, and location. These dimensions provide useful context for understanding differences in energy prices (LMPs) over the review period. The first subsection (3.1.1) summarizes energy market pricing over a five-year period, reviews price separation across load zones, and examines load-weighted LMPs, which provide an indication of the effective prices that load-serving entities pay for energy. The second subsection (3.1.2) estimates the impacts of fast-start pricing rules on LMPs and other market outcomes. Finally, the third subsection (3.1.3) examines the extent to which prices converged across the day-ahead and real-time energy markets, which is a useful barometer of market efficiency.

Key Takeaways

Energy market prices decreased significantly in 2023, returning to pre-2022 levels. The price decrease reflected a lack of sustained cold weather during the winter months and a less constrained natural gas system, and the settling of international energy markets following the Russian invasion of Ukraine. Overall, prices were consistent with observed market conditions, including input fuel costs, load levels, and generator operations.

- The Hub price was $36.82/MWh in the day-ahead market (or $39.19/MWh in load weighted-terms), down 57% from $85.56/MWh ($91.36/MWh load-weighted) in 2022. A decrease of similar magnitude occurred in the real-time market, with a 2023 average Hub price of $35.70/MWh. This change was consistent with lower natural gas prices in 2023, which fell by 67% relative to 2022. Gas-fired generators set price for 84% of load in the real-time energy market.
- Day-ahead and real-time Hub prices were comparable on average, indicating that the day-ahead market performed reasonably well in predicting expected real-time outcomes; the day-ahead energy price at the Hub exceeded the real-time price by an average of $1.12/MWh in 2023.
- Zonal prices exhibited small degrees of separation reflecting low levels of both transmission losses and congestion. The Connecticut load zone had the lowest overall average prices, $0.78/MWh (2.1%) lower than the Hub price in the day-ahead market reflecting supply of relatively cheaper generation and areas of congestion that limit the export of that supply. Comparing Hub and zonal LMPs, the average absolute difference between the zonal and Hub prices was $0.31/MWh in both markets.

Fast-start pricing is generally meeting the design's key objective of improving real-time price formation by better reflecting the production costs of flexible, fast-start resources in energy prices and reducing uplift payments. There continued to be significant periods of non-zero pricing and payments during times when the reserve constraint was not impacting the physical dispatch of resources and there was a physical surplus of reserves. We continue to recommend that the ISO assess this issue.

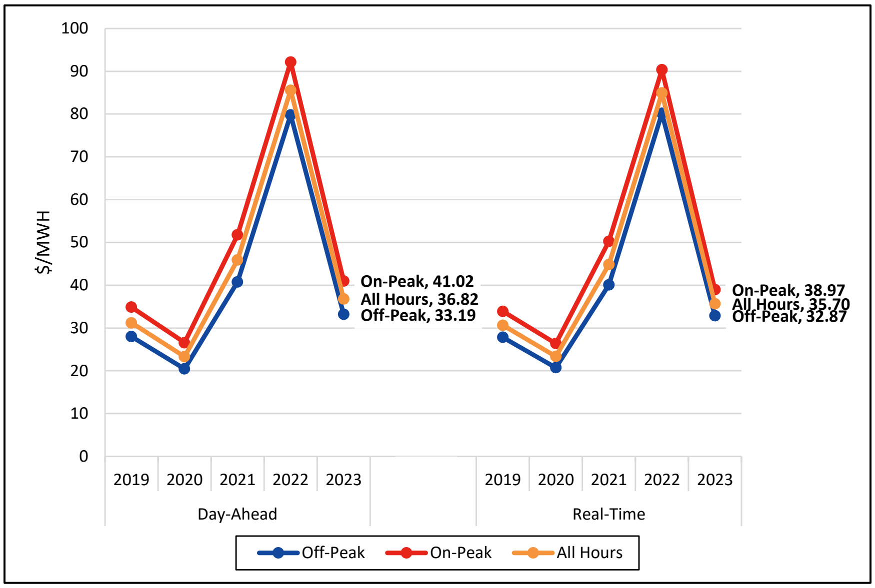
3.1.1 Day-Ahead and Real-Time Energy Price

Day-ahead and real-time energy prices at the Hub and the eight New England load zones are presented below. These prices are evaluated across a number of dimensions: time-of-use (e.g., peak, off-peak hours), location, and load-weighting.

Hub prices by time-of-use and market

First, Figure 3-1 shows simple average Hub prices in the day-ahead and real-time markets for three time tranches: all hours, peak, and off-peak hours.[124]

Figure 3-1: Annual Simple Average Hub Price



Average Hub prices in 2023 declined significantly from their 2022 levels. In 2023, the simple annual average Hub price (in *all hours*) was $36.82/MWh in the day-ahead market and $35.70/MWh in the real-time market; down 57% in the day-ahead market and 58% in the real-time market.

These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Natural gas prices, which are the primary driver of energy prices, decreased by 67% on average in 2023 and gas generators set price for 84% of load in the real-time energy market.

Pricing by time-of-day (i.e., *on-peak and off-peak*) in 2023 exhibited the same trend; average on-peak prices decreased by 55% in the day-ahead market and 57% in the real-time market, while average off-peak prices decreased by 58% in the day-ahead market and 59% in the real-time market, respectively.

Day-ahead and real-time Hub prices were comparable on average, indicating that the day-ahead market performed reasonably well in reflecting expected real-time outcomes. Differences in

[124] On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC) holidays); the off-peak period encompasses all other hours.

average prices ranged from $0.32/MWh (1%) for the off-peak period to $2.04/MWh (5%) for the on-peak period.

Prices by load zone and market

At the *zonal* level, price differences were small in 2023 in both the day-ahead and real-time energy markets. Load zone prices were quite close to the Hub price, with an absolute average price difference between the Hub and zones of $0.31/MWh in each market, reflective of a system that is generally uncongested.

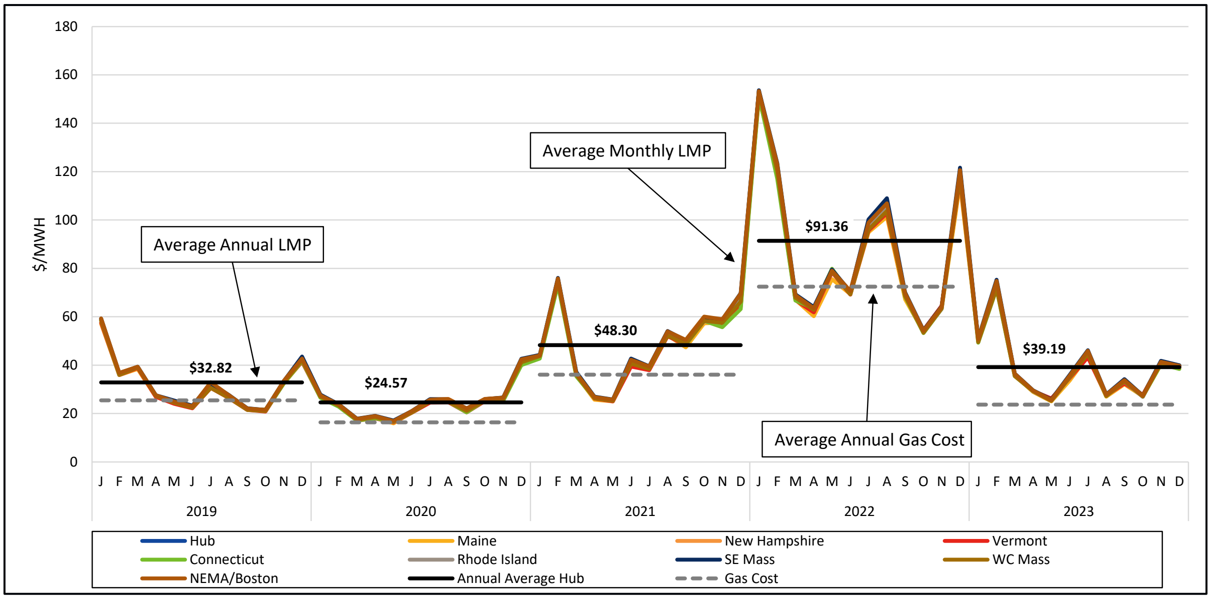
The Connecticut load zone had the lowest overall average prices in the region in 2023. Connecticut's prices averaged $0.78/MWh (2.1%) lower than the Hub price in the day-ahead market and $0.64/MWh (1.8%) lower than the Hub price in the real-time market. This pricing outcome reflects surplus supply conditions with relatively cheaper generation in that state, as well as areas of congestion that limit the export of that supply. Conversely, the Northeastern Massachusetts (NEMA) load zone had the highest average prices in the day-ahead and real-time markets. NEMA's average day-ahead and real-time prices were slightly higher than the Hub, by $0.30/MWh in each market. In each case, losses accounted for the majority of the difference between the zone and Hub price.

Consumer prices: load-weighted prices

Compared to the simple-average prices presented above, load-weighted prices are a better indicator of average prices that load-serving entities (LSEs) pay for energy.[125] The amount of energy consumed in the markets can vary significantly by hour. Load-weighted prices reflect the increasing cost of satisfying demand during peak consumption periods when higher demand necessitates the commitment and dispatch of more expensive generators. Because of this, load-weighted prices tend to be higher than simple average prices. The average load-weighted prices were $39.19 and $38.25/MWh in the day-ahead and real-time markets in 2023, respectively. Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-2 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility.

[125] While a simple-average price weights each energy market price equally across the day, load-weighting reflects the proportion of energy consumed in each hour: load-weighted prices give greater weight to high-load consumption hours than to low-load consumption hours, with each hour being weighted in proportion to total consumption for the entire day.

Figure 3-2: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2019 to 2023 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Winter periods with high fuel prices and summer months with elevated load variability typically have the highest load-weighted prices; a similar trend applies to the real-time market. The effect of natural gas prices in 2023 is evident in the figure above, with day-ahead LMPs decreasing from their high 2022 values in line with the lower cost of natural gas.

3.1.2 Fast-Start Pricing: Impact on Real-Time Outcomes

The fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs. The purpose of fast-start pricing rules is to improve energy price formation when fast-start units are operating. Fast-start pricing rules allow LMPs to better-reflect the marginal cost of fast-start resource deployment and, therefore, send more transparent short- and long-term market signals about the cost to operate the system.

We find that fast-start pricing is generally meeting the design's key objective of improving real-time price formation by better reflecting the production costs of flexible, fast-start resources in energy prices.[126] In 2023, fast-start pricing impacts were similar to prior years. There continued to be significant periods of non-zero pricing (and payments) during times when the reserve constraint was not impacting the physical dispatch of resources and there was a physical surplus of reserves. We recommended that the ISO assess this issue in our 2022 Annual Report.[127]

The following table compares a number of actual and estimated counterfactual market outcomes. The column labeled *Fast-Start Pricing* details actual pricing and settlement outcomes.

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[126] For more detail on fast-start pricing, see our *Summer 2017 Quarterly Markets report* (December 20, 2017), Section 5.5, available at https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

[127] A summary of this and other recommendations can be found in the executive summary of this report.

The column labeled *Non-Fast-Start Pricing* provides estimates of counter-factual outcomes if fast-start pricing had not been implemented.

Table 3-1: Fast-Start Pricing Outcome Summary, 2023

Market Outcome	Fast-Start Pricing (Actual Outcomes)	Non Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP ($/MWh)[128]	$35.55	$32.79	**$2.76 (8%)**
Real-Time Energy Payments ($, Millions)[129]	$69.3	$56.0	**$13.2 (24%)**
NCPC Payments ($, Millions)[130]	$23.9	$33.5	**-$9.7 (-29%)**
Reserve Prices ($/MWh)[131]	$1.35	$0.48	**$0.86 (179%)**
Real-Time Reserve Payments ($, Millions)[132]	$17.4	$4.0	**$13.3 (333%)**
Percent of Intervals with Reserve Pricing (%)	8.1%	4.7%	**3.4% (74%)**
Intervals Fast-Start Resource Marginal[133]	23.0%	10.2%	**12.8% (126%)**

To summarize the key takeaways, the fast-start pricing mechanics:

- resulted in a higher frequency of fast-start resources setting price,
- increased the average annual system LMP by 8% and increased real-time energy payments by 24%,
- decreased real-time NCPC paid to generators and asset-related demand (ARDs) by 29%[134], and
- had a substantial impact on reserve pricing and payments, with non-zero pricing occurring in 74% more intervals. Overall, average reserve prices were 179% higher in the fast-start-pricing case than in the non-fast-start-pricing case and payments were 333% higher.

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[128] The system LMP shown here is the energy component of the LMP in each interval.

[129] This value is different than the real-time payments value reported in the wholesale cost section of the report because, here, real-time load deviations are only considered for locations and customers with physical load (i.e., exports and day-ahead demand that does not correspond to physical load are excluded).

[130] NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments for generators and asset-related demand resources (ARDs). Due to data limitations, counterfactual LMPs were not available in every interval so estimated payments are slightly less than actual payments. Actual payments (i.e., not based on IMM estimates like the data shown in the table) in 2023 were $24.0 million.

[131] These reserve prices represent the average reserve price in every interval – including $0/MWh reserve price intervals.

[132] The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments. For more information on the impact of fast-start pricing on reserves, see Section3.1.2.

[133] This metric represents the percentage of intervals in which at least one fast-start generator that was marginal (i.e., set price).

[134] Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit and dispatch-out-of-merit NCPC to generators that did not recover their costs when following ISO dispatch instructions by 41%. The decrease was offset by an increase in Rapid Response Pricing Opportunity Cost (RRPOC) NCPC.

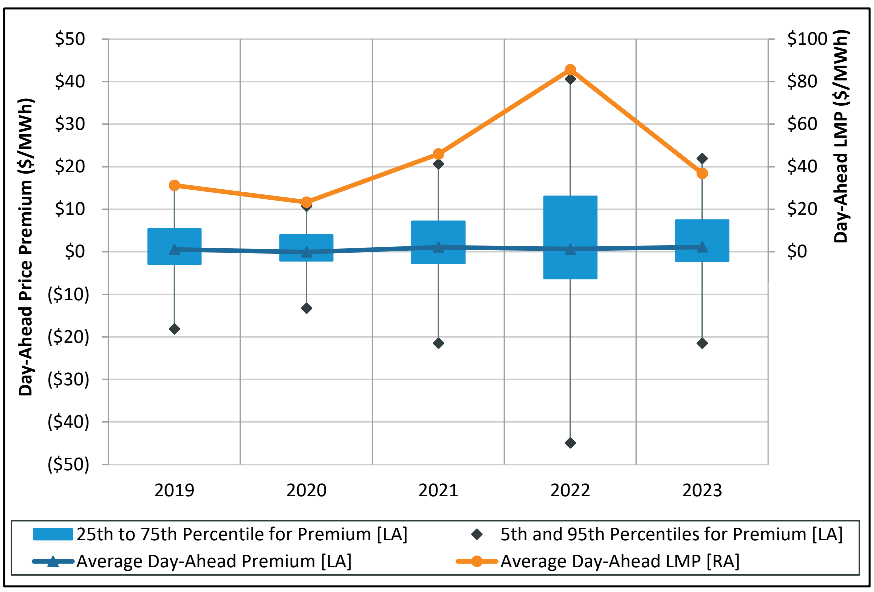
3.1.3 Energy Price Convergence

Price convergence refers to the extent to which prices equate across the day-ahead and real-time energy markets. Price convergence serves as a metric for market efficiency – which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. One way to assess price convergence is to look at the difference between day-ahead and real-time prices (i.e., the day-ahead price premium).[135] In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices. While day-ahead prices will almost never perfectly match real-time prices in any given hour (because real-time conditions will usually differ from expectations), one might expect to see similar average prices between the two markets over time.

Convergence across all hours

The average day-ahead price premium at the Hub in 2023 remained in line with recent historical values. This can be seen in Figure 3-3, which shows the distribution of the day-ahead price premium at the Hub between 2019 and 2023 using a box-and-whiskers diagram.[136] This figure also shows the average annual day-ahead Hub LMP (orange line).

Figure 3-3: Average Annual Day-Ahead Price Premium at the Hub and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $1.12/MWh in 2023, a moderate increase from 2022 when the premium was $0.64/MWh. Notably, in March 2023, over-clearing of demand in the day-ahead market led to the highest average day-ahead premium of the year ($4.25/MWh), due to an increase in average cleared virtual demand. In percentage terms (as a percentage of the day-ahead LMP), the 2023 price premium (3.0%) was the highest in the reporting period. Between 2019 and 2023, the average price premium ranged from as low as -$0.06/MWh (in 2020) up to the high seen this year. A decreased amount of variability in the day-ahead price premium in 2023 is also evident in Figure 3-3. While the narrowing price ranges might suggest

[135] The day-ahead price premium is defined as the day-ahead energy price *minus* the real-time energy price.

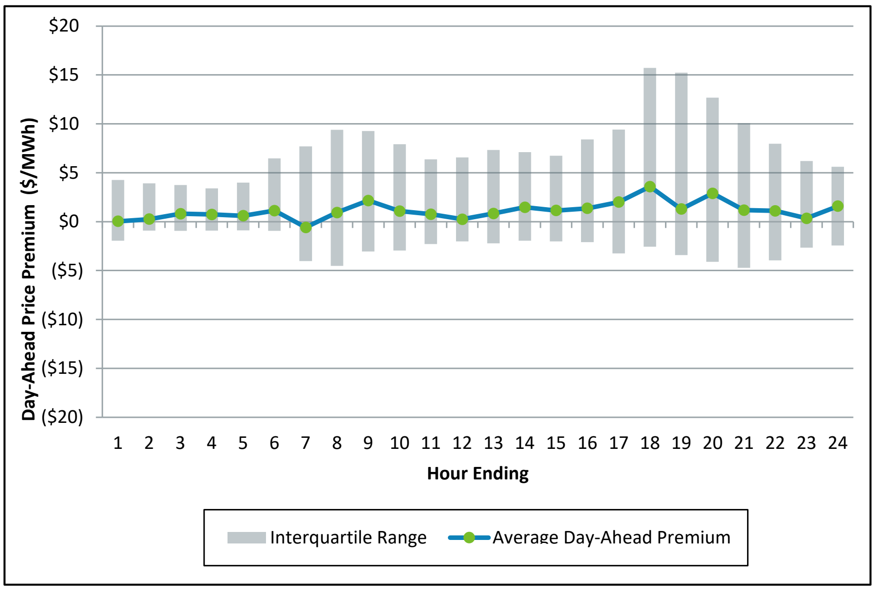
[136] The day-ahead price premium is measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

improving price convergence, it is important to note that, over time, these percentiles generally track the average day-ahead Hub LMP (orange series, right axis).

Convergence by time of day

While average day-ahead price premiums were reasonably consistent through the day, there was more variability in certain hours. Figure 3-4 below shows, by hour, the average day-ahead price premium at the Hub (blue line). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead price premium.

Figure 3-4: Average Hourly Day-Ahead to Real-Time Hub Price Differences, 2023



The average day-ahead price at the Hub exceeded the average real-time price during all but one hour in 2023 (HE 7). The day-ahead price premium ranged from -$0.59/MWh (HE 7) to $3.58/MWh (HE 18). Increased virtual supply potentially helped improve day-ahead and real-time price convergence during the middle of the day in 2023 (see Section 5).

3.2 Supply-side Factors

This section examines the key factors influencing supply in our markets, starting with generation costs and specifically focusing on fuel and emissions. Following this, it examines utilization rates of different generator technologies, marginal or price-setting resources, and concludes with an assessment of supply offer behavior.

Key Takeaways

Natural gas is one of the most important factors in explaining outcomes and trends in New England's energy markets. This is due in large part to the frequency with which gas-fired generation is the marginal (i.e., price setting) resource type; in 2023, natural gas was the marginal fuel for 40% of load in the day-ahead market in 2023 and 84% in the real-time market.

Regional Greenhouse Gas Initiative (RGGI) carbon dioxide emissions costs rose to their highest level in 2023, and are a significant driver of energy prices, especially in the context of lower input fuel costs; these costs represented an estimated $6.19/MWh (26% of production costs) for the typical natural gas-fired generator.

Nuclear generation experienced a significant decrease in capacity factor due to prolonged outages. This resulted in less fixed supply on the system, which was replaced by more expensive gas-fired generation. Oil generation also saw lower utilization, driven by the significant year-over-year drop in natural gas prices and a lack of sustained cold periods.

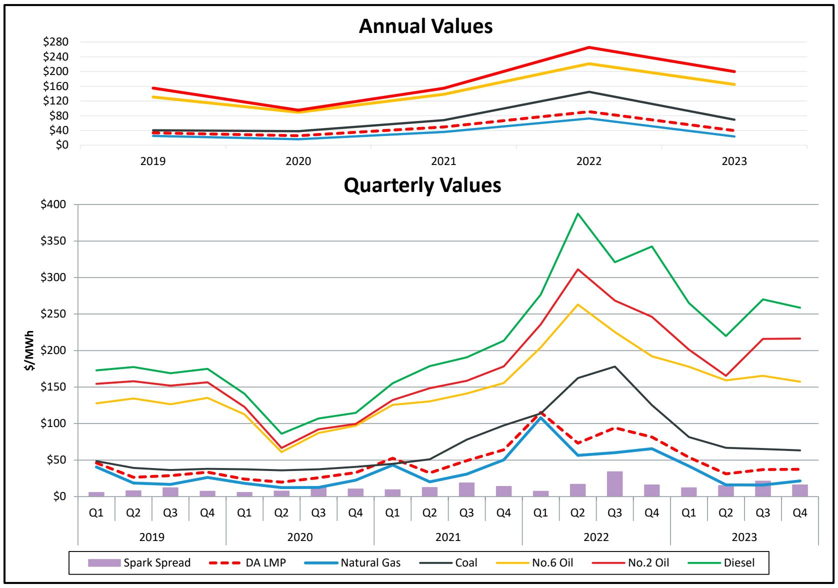
Non-price-setting supply accounted for 68% of total supply in both day-ahead and real-time markets, consistent with previous years. The presence of large volumes of non-price-setting supply can lead to low or negative prices, although the frequency of such occurrences remained relatively low in 2023. We generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand.

3.2.1 Generation Costs

Day-ahead and real-time electricity prices remain closely correlated with the estimated cost of operating a natural gas-fired generator. In 2023, natural gas-fired generators continued to be the dominant price setters and supplied over 55% of native generation. The relationship between electricity prices and generation fuel costs is shown in Figure 3-5 below, alongside the estimated spark spread (gross margin) of a natural gas-fired generator.[137]

[137] Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the day-ahead on-peak LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8.

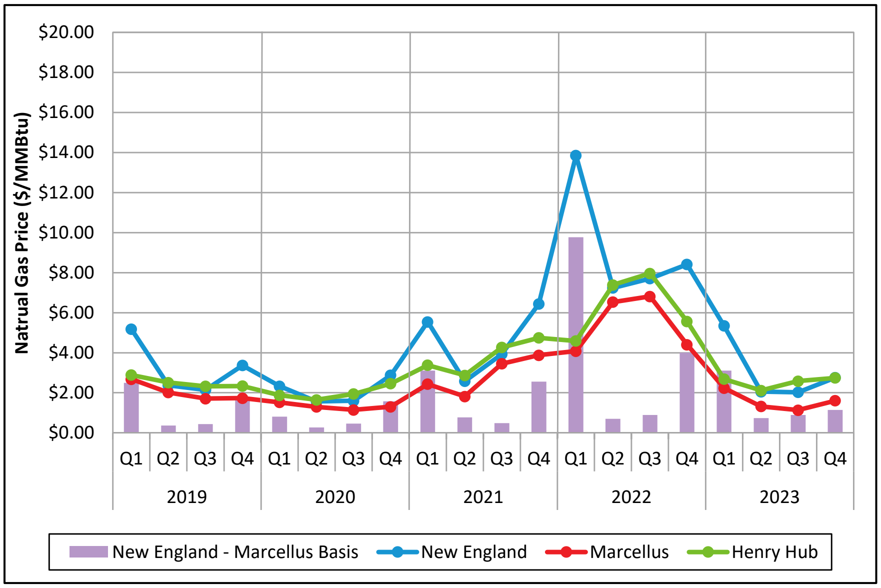
Figure 3-5: Estimated Generation Costs and On-Peak LMPs



Estimated natural gas generation costs averaged $23.68/MWh in 2023, down 67% from 2022. Generation costs fell from elevated levels driven by global market uncertainty and severe weather in 2022 as discussed in Section 1.2, returning to levels roughly in line with prior years. Spark spreads averaged $16.07/MWh, down 13% from 2022 as LMPs and natural gas declined in 2023. However, estimated spark spreads remained above 2019-2021 averages, indicating relatively profitable conditions for typical gas-fired generation. Generation costs were highest in Q1 during winter weather, averaging $41.72/MWh as relatively high natural gas prices reduced generator profits. Estimated spark spreads peaked in Q3 at $21.21/MWh, when higher demand driven by high air conditioning coupled with low natural gas prices created profitable conditions for efficient gas generators.

The relationship between New England gas prices and Henry Hub and Marcellus prices is shown in Figure 3-6 below.

Figure 3-6: New England vs. Henry Hub and Marcellus Natural Gas Prices



New England natural gas prices fell 67% in 2023 relative to 2022, in line with year-over-year decreases at Henry Hub and Marcellus. During constrained winter periods, the New England natural gas price can diverge significantly from national hub prices due to residential heating demand, as shown by the basis between New England and Marcellus hub prices reaching $4.01/MMBtu in Q1 2022. While spreads between Q1 2023 New England and hub prices primarily reflect temporary price spikes during brief periods of freezing weather, Q1 basis fell 68% from 2022 and remained comparable to spreads in Q1 2021.[138] Spreads in Q4 2023 remained low during relatively mild weather conditions.

Industry-standard profitability metrics

Industry-standard profitability metrics for gas-fired generators include implied heat rates and spark spreads. Implied heat rates reflect the efficiency of a hypothetical generator that would break even at given LMPs and gas prices. Spark spreads reflect the gross profit margin between LMPs and gas prices for generators of a given heat rate. Notable reference heat rates include 7,800 Btu/kWh, the estimated average heat rate for a New England gas generator, and 6,451 Btu/kWh, the standard efficiency of a new entrant combined cycle gas-fired generator.[139] Implied heat rates and spark spreads across several reference heat rates for 2019-2023 are shown in Table 3-2.

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[138] For example, temperatures reached -10°F on February 3, and gas prices soared to $76.42/MMBtu before falling to more typical levels the next day.

[139] The IMM uses 7,800 Btu/kWh to represent the average heat rate of New England natural gas generators. The estimated new entrant combined cycle heat rate is provided in the ISO-NE Net Cone and ORTP Analysis performed by Concentric Energy Advisors, Inc. and cited in ISO filings to the Federal Energy Regulatory Commission for FCA 16. The analysis estimates that a new entrant combined-cycle unit would have a heat rate of 6,394 Btu/kWh in shoulder seasons, 6,573 Btu/kWh in summer, and 6,429 Btu/kWh in winter. Weighting these estimates by the number of days in a year yields an average heat rate of 6,451 Btu/kWh. See *ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward* (December 2020), p. 35, available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

Table 3-2: Annual Average On-Peak Implied Heat Rates and Spark Spreads

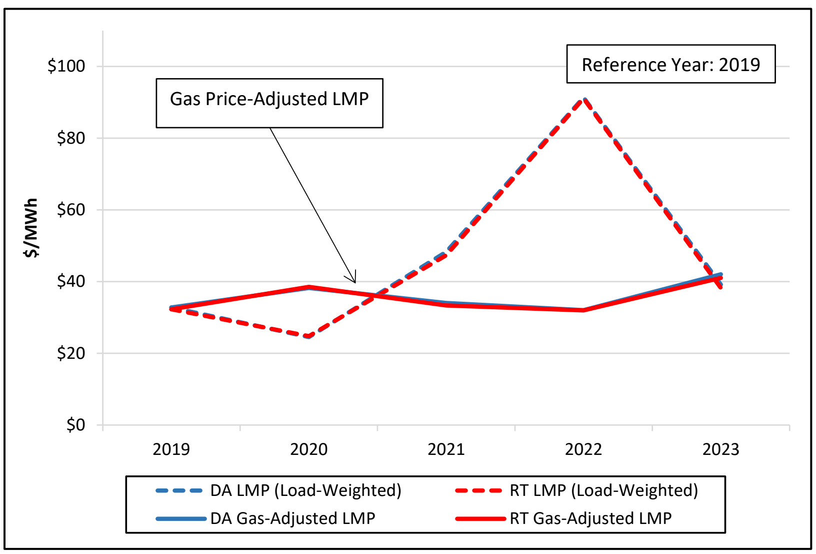
Year	Day-Ahead On-Peak LMP ($/MWh)	Gas Price ($/MMBtu)	Implied Heat Rate (Btu/kWh)	Spread ($/MWh) corresponding to Heat Rate (Btu/kWh)					
				6,451	7,000	7,800	8,000	9,000	10,000
2019	34.89	3.26	10,710	13.88	12.09	9.48	8.83	5.57	2.31
2020	26.57	2.09	12,686	13.06	11.91	10.24	9.82	7.72	5.63
2021	51.77	4.62	11,193	21.93	19.39	15.69	14.77	10.14	5.52
2022	92.17	9.28	9,927	32.27	27.18	19.75	17.89	8.61	(0.68)
2023	41.02	3.04	13,512	21.43	19.77	17.34	16.73	13.70	10.66

Both gas prices and peak LMPs decreased in 2023 relative to 2022. Implied heat rates rose 36% to 13,512 Btu/kWh in 2023 as gas-fired generation increased as a share of total generation. Spark spreads for average existing gas-fired generators ($17.34/MWh) and new entrant combined cycle gas-fired generators ($21.43/MWh) both fell from 2022 but remain above averages from 2019-2021, indicating profitable conditions for efficient gas-fired generators throughout the year.[140]

Natural Gas Price-Adjusted LMP

Although there is a significant positive correlation between changes in LMPs and changes in natural gas prices, LMPs are also influenced by other factors such as shifts in the energy supply mix, system demand, and unforeseen events such as unplanned equipment outages. The gas price-adjusted LMP is a high level metric used to estimate the impact of these non-gas price factors on the energy price and is shown in in the Figure 3-7 below.[141]

Figure 3-7: Annual Average Natural Gas Price-Adjusted LMPs



With the exception of 2020 and 2023, the day-ahead and real-time gas price-adjusted LMPs were within a relatively narrow band ($29-$34/MWh) on average. This indicates that the

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140 Note that these estimated spark spreads do not include any emissions costs. See below for a detailed discussion of New England emission programs and their impacts on generation costs.

141 The gas price-adjusted LMP is derived by dividing the reference year natural gas price (2019) by the current year natural gas price, then multiplying by the load-weighted LMP.

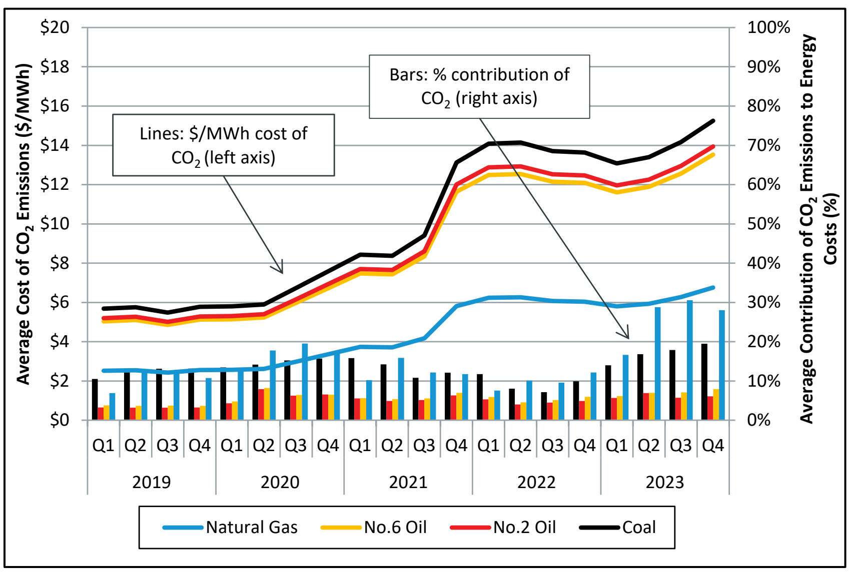
changes in gas prices explained nearly all of the change in the LMP. In 2023, on a gas price-adjusted basis, day-ahead and real-time prices increased by 31% (from $32.06 to $42.06/MWh) and 28% (from $31.98 to $41.05/MWh), respectively. This outcome was largely due to increased nuclear outages and a decrease in net imports during the second and third quarters. This resulted in less fixed supply on the system, which was replaced by more expensive gas-fired generation, reflecting similar market conditions to 2020.

Regional Greenhouse Gas Initiative (RGGI) Prices

The key driver of emissions costs for generators in New England is RGGI, a marketplace for CO_2 credits in the Northeast and Mid-Atlantic regions; it covers all six New England states. RGGI operates as a cap-and-trade system, where fossil fuel-fired generators must purchase emission allowances equal to their level of CO_2 emitted over a specific compliance period.[142]

The average estimated dollar per MWh costs of CO_2 emissions and their percent contribution to total variable production costs are shown in Figure 3-8 below.[143] The line series illustrate the average estimated cost of emissions allowances by fuel type for the past five years. The bar series show the proportion of the average energy production costs attributable to CO_2 emissions costs for each year.[144]

Figure 3-8: Estimated Average Cost of RGGI CO_2 Allowances and Contribution of Emissions to Energy Production Costs



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[142] See RGGI's *Elements of RGGI* page, available at https://www.rggi.org/program-overview-and-design/elements

[143] Only fuel and CO_2 emission costs are considered in calculating the variable cost of each generator. In practice, generators incur other variable operating and maintenance productions costs, but fuel comprises the vast majority of variable costs. CO_2 prices in $ per ton are converted to estimated $/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel. This figure shows the CO_2 costs associated with the RGGI program only. Generators in Massachusetts are subject to additional CO_2 costs from the Massachusetts EGEL program, which is covered further below.

[144] RGGI accounts for nearly all of emissions costs.

The estimated RGGI costs for generators of all fuel types increased slightly over the period. RGGI allowance prices increased by 0.7% in 2023 (from $13.48/short ton in 2022 to $13.57/short ton in 2023). For a typical natural gas-fired generator the average estimated CO_2 cost was $6.19/MWh in 2023, a modest increase of just $0.04/MWh from 2022.

The bars in Figure 3-8 show the relative contribution of emissions allowance costs to generator energy costs. This contribution increased for all fuel types in 2023, although the cost of CO_2 increased just 0.7%, on average, from the previous year. The contribution of higher CO_2 prices to generator costs was greater due to the 67% decrease in natural gas prices from 2022 to 2023. The average contribution of RGGI CO_2 emissions to energy costs for a standard natural gas generator increased from 10% in 2022 to 26% in 2023.

In 2023, the average RGGI allowance price remained around $13/short ton of CO_2, but secondary market prices reached over $15/short ton by the end of the year. There were several factors that potentially influenced the price of RGGI allowances:

- The Cost Containment Reserve (CCR), which sells additional allowances held in reserve if prices rise above an established price. This limits volatile upward price movements.[145]
- The Emission Containment Reserve (ECR), which withholds allowances from circulation to secure additional emissions reductions if prices fell below an established price. This limits volatile downward price movements.[146]
- The conclusion of the third RGGI program review in 2023, signaling potential further emission reductions similar to the second program review in 2017.[147]
- The number of allowances available at auction continues to decline.[148]

Massachusetts EGEL (310 CMR 7.74)

The Massachusetts CO_2 cap-and-trade program has been in place since 2018.[149] In addition to the RGGI program previously mentioned, Massachusetts generators must also comply with this program's additional requirements. Administered by the Massachusetts Department of Environmental Protection (MassDEP), the program places an annual cap on aggregate CO_2

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[145] In the last auction of 2023, prices exceeded the Cost Containment Reserve (CCR) of $14.88/short ton resulting in a partial depletion of the CCR. See Potomac Economics' *Market Monitor Report for Auction 62* (December 9, 2023) p. 9, available at https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/62/Auction_62_Market_Monitor_Report.pdf

[146] In 2023, the ECR trigger price was $6.87/allowance, which will rise 7% each year through 2030. See Potomac Economics' *Secondary Market for RGGI CO_2 Allowances: Third Quarter 2023* report (November 2023), p. 12, available at https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2023_Q3.pdf

[147] See RGGI's *Program Review* page, available at https://www.rggi.org/program-overview-and-design/program-review

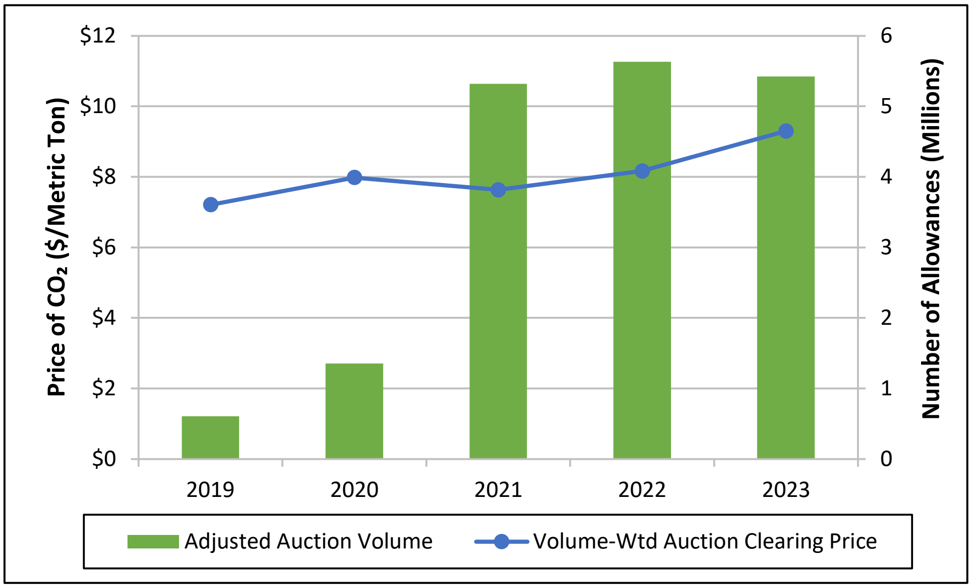
[148] The RGGI cap is set to decline 30% from its 2020 level by 2030. This is a reduction of about 2.3M tons of CO_2 per year. See *RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030* (August 23, 2017), available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf

[149] See the Massachusetts Department of Environmental Protection's page *Electricity Generator Emissions Limits (310 CMR 7.74),* available at https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

production for the majority of fossil fuel-fired generators within the state.[150] The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050.[151, 152]

The annual volume of CO_2 allowances sold at auction and the respective volume-weighted auction clearing prices for the MA EGEL program are shown in Figure 3-9 below.[153, 154]

Figure 3-9: Massachusetts EGEL Auction Results



The volume-weighted annual auction clearing prices increased about 14% to $9.30/metric ton of CO_2 in 2023 from the previous year. Although annual average prices increased, clearing prices at auction ranged from $3.00 to $14.20/metric ton of CO_2. This volatility may reflect market uncertainty regarding the underlying value of allowances and significantly lower

[150] Participating generators are fossil fuel-fired generators with a nameplate capacity of 25 MW or more. See Massachusetts Department of Environmental Protection's *310 CMR 7.00: Air Pollution Control* report, available at https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download

[151] The annual emissions cap for 310 CMR 7.74 will reduce by 223,876 metric tons in each subsequent year, eventually reaching 1,791,019 metric tons in 2050.

[152] The regulation requires fossil fuel-fired generators to hold an allowance for each metric ton of CO_2 they produce during a year. For the first two years, these allowances were primarily allocated based on historical emissions levels, but beginning in 2021, allowances were available for sale through auction only. The program also allows generators to trade emissions allowances to meet their compliance obligations. For more information on allowance allocations see Potomac Economics' *Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter 2021* (November 2021), available at https://www.mass.gov/doc/market-monitor-quarterly-report-2021-q3/download

[153] For the 2019 and 2020 compliance years, MassDEP directly allocated 75 and 50% of emissions cap. Beginning in 2021, MassDEP no longer distributed allowances through direct allocation and all allowances were offered at auction.

[154] There were fewer allowances at auction in 2021 compared to 2022 because there were more allowances banked going into that year. Emission caps are adjusted based on banked allowances. For example, to calculate the 2022 cap, you subtract the 2.7 million banked allowances minus 223,875 (because the number of banked allowances is over 223,875) from original cap of 8 million to get 5.6 million metric tons of CO_2 emissions.

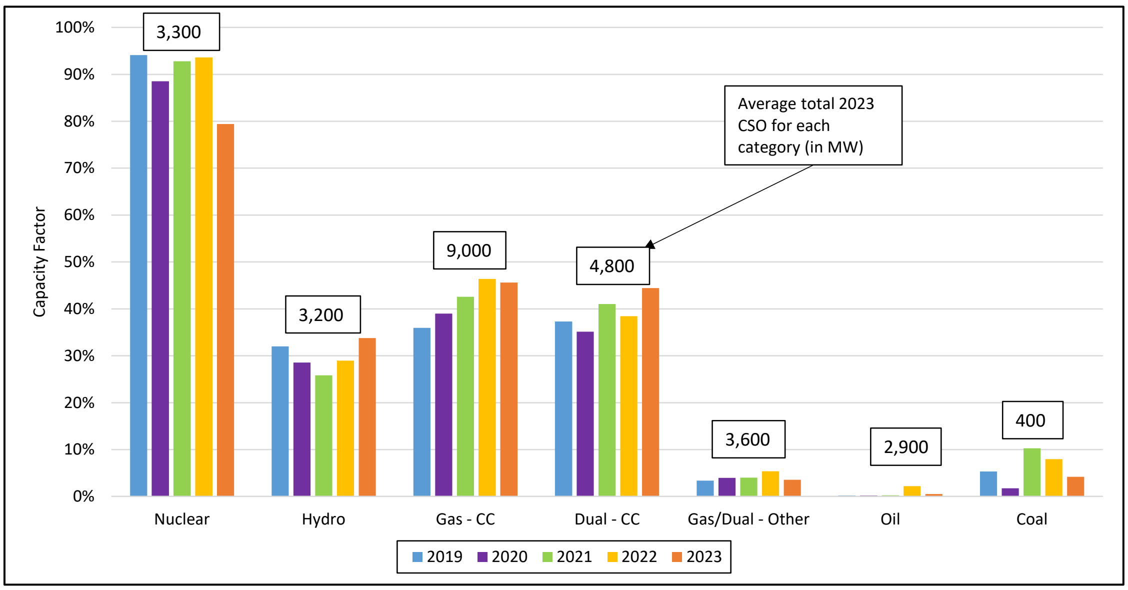
estimated emissions from program participants in comparison to the annual cap.[155] After a program review, 2023 was the first year that a limited number of future vintage allowances were sold at auction. The clearing prices for the 2024 vintage allowances ranged from $3.00-$6.53/metric ton of CO_2.

In general, generators continued to incorporate the cost of allowances into their energy market supply offers.[156] As the number of available allowances decreases, prices are expected to rise. If the volume of secondary market transactions remains low, participants may find it difficult to obtain additional allowances without paying significant premiums.[157]

3.2.2 Capacity Factors

Capacity factors provide a high-level view of the relative economics and physical capabilities of resources, and for the purposes of this report is measured as the ratio of a resource's average hourly output over their total capacity supply obligation (CSO). Low capacity factor resources tend to rely more on revenue from the capacity market, compared to energy and ancillary markets, to recover their going forward costs of operation. The individual capacity factors are aggregated by fuel type and shown in Figure 3-10 below.

Figure 3-10: Capacity Factor by Fuel Type



In 2023, nuclear generation saw the largest decrease in capacity factor due to prolonged outages resulting in a 500 MW decrease in average hourly generation compared to 2022. Hydro and dual-fuel combined cycle (CC) generators saw a modest increase in capacity factor in 2023, with hydro generation increasing by 200 MW (7%) due to higher precipitation levels, and dual-

[155] Estimated emissions for generators impacted by MA EGEL were about 5.4M metric tons of CO_2 in 2023. The cap is not scheduled to fall below this level until 2034.

[156] To incorporate the cost of these allowances into generator reference levels, the IMM uses an adder that values the allowances based on recent trades and auction results.

[157] See Potomac Economics' *Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter 2023* (November 2023), available at https://www.mass.gov/doc/market-monitor-quarterly-report-2023-q3/download

fuel CC generation increasing by 267 MW (14%) year-over-year. Combined cycle capacity utilization trended up as newer and more efficient CCs filled the gap left by reduced imports.

Oil and coal generation saw significantly lower capacity factors in 2023, albeit from a low baseline. Oil-fired generation utilization hinges on high-demand periods or prolonged cold spells that lead to spikes in gas prices. However, such opportunities have been scarce in recent years, evident in the low frequency of system events and prolonged cold spells. This low utilization of oil-fired generation highlights their reliance on capacity market revenues, particularly when compared to combined cycle generators.

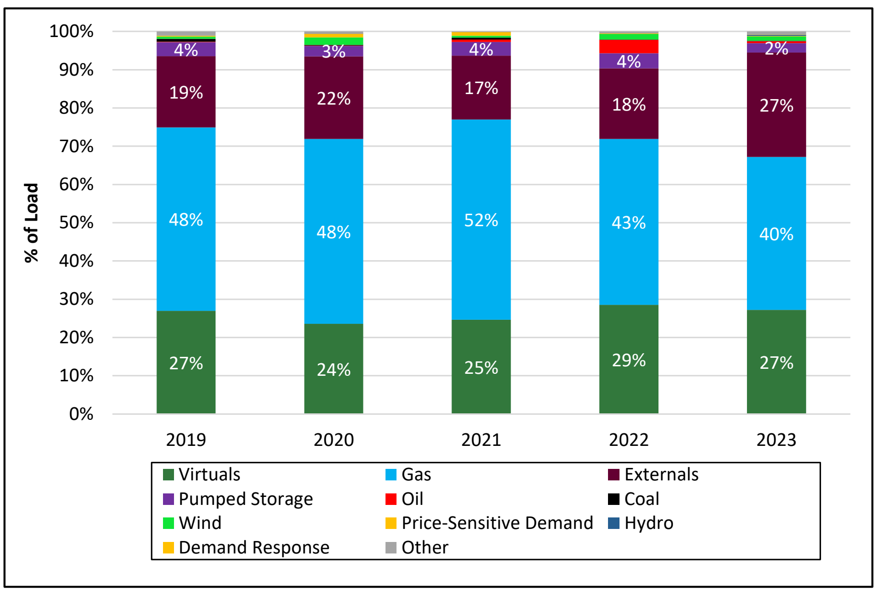
3.2.3 Marginal Resources

Below we present statistics on marginal, or price-setting, units by transaction and fuel type on a load-weighted basis in both the day-ahead and real-time energy markets.[158] Trends in marginal resources provide insights into the cost drivers of energy prices, which is particularly evident in high frequency of natural gas generators setting price.

Day-Ahead Energy Market

The percentage of load for which each transaction type was marginal in the day-ahead energy market over the last five years is illustrated in Figure 3-11 below.[159]

Figure 3-11: Day-Ahead Marginal Resource by Transaction Type



[158] When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area. It is important to note that, while this section falls within the supply-side section, both demand and supply can set price in the energy market.

[159] The "other" category contains energy storage, wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

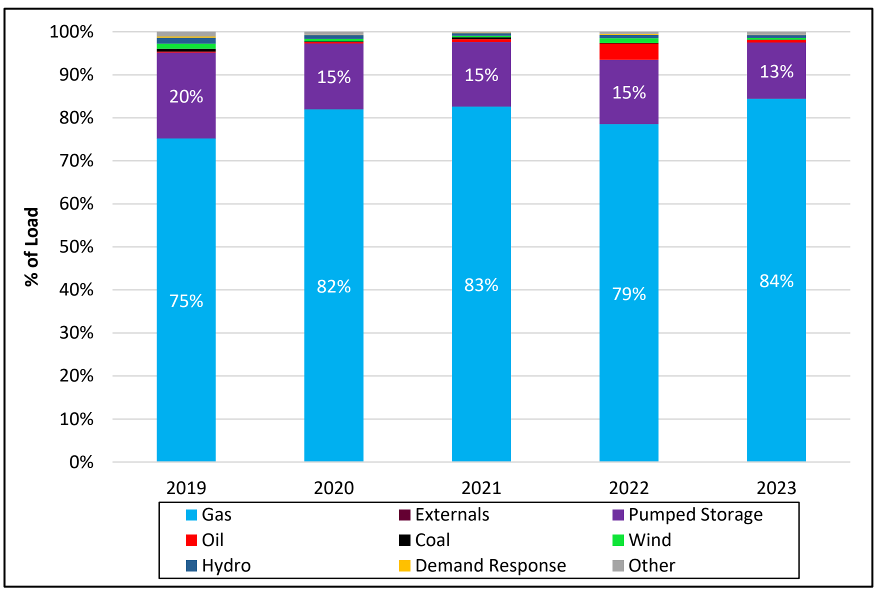
Collectively, gas generation, virtual transactions and external transactions set price for the vast majority of load in the day-ahead market in 2023 (95%). Gas-fired generation was the most common marginal resource type in 2023, setting price for 40% of total day-ahead load. However, this represented the smallest percentage of load for which gas was marginal over the last five years. One of the primary reasons for this was because external transactions grew to their largest value of the reporting period in 2023 (27%) as lower LMPs resulted in external offers being closer to the margin. Notably, external transactions over the Canadian interfaces were marginal for higher percentages of load, collectively increasing from 4.9% in 2022 to 13.2% in 2023.[160] Virtual transactions continued to set price frequently and at a comparable rate across the five years. Meanwhile, oil generation dipped from 3% in 2022 to close to 0% in 2023 as winter temperatures were generally higher, leading to fewer opportunities where oil generation was at or near the margin.

Demand, including price-sensitive demand, asset-related demand (ARDs), virtual demand, and export transactions, can set price in the day-ahead market. In 2023, these forms of demand collectively accounted for 22% of load in the day-ahead market while supply represented the other 78%.

Real-Time Energy Market

The percentage of load for which each transaction type was marginal in the real-time energy market over the last five years is illustrated in Figure 3-12 below.

Figure 3-12: Real-Time Marginal Resource by Transaction Type



As with prior years, natural gas-fired generators set price for the highest percentage of load in the real-time market in 2023 (84%).[161] Pumped-storage generation (9%) and demand (4%)

[160] The percentage of cleared external transactions from Canada that were priced (rather than fixed) grew between 2022 and 2023. The composition of these transactions is looked at in greater detail in Section 4.

[161] Unlike the day-ahead market where offers and bids that are *physical* or *financial* in nature can be marginal, in the real-time market only *physical* assets can set price. This means that the real-time price is typically set by generators, pumped-storage demand, and demand response resources.

was the second largest price-setter (13%). This represents the smallest share associated with pumped-storage facilities over the entire reporting period. One of the primary drivers for this reduction were planned outages for several of these units that extended over three months in the fall and winter. While wind generators are frequently marginal in real time, the load within the constrained areas where they set price tends to be quite small. In 2023 wind generators were the marginal fuel type for less than 1% of real-time load.

3.2.4 Supply-Side Participation

Some resources are willing to clear in the energy market at any price, while others offer supply at a specific price that determines whether or not the resource is committed. The volumes of price-setting vs. non-setting price supply on the system have important implications for price formation. For example, if most supply cannot set price, there is a higher likelihood of low or negative LMPs.

In 2023, non-price-setting-supply made up 68% of total supply in the energy market, a level similar to previous years. Non-price-setting supply consists of offers from suppliers that are willing to sell (i.e., clear) at any price, and offers that cannot set price. Market supply may be insensitive to price for a number of reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 32% of supply is considered priced-setting supply (i.e., it is willing to sell at a specified offer price or higher, and has the ability to set price).

There are three categories of *non-price-setting* supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are scheduled to flow power into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).[162]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is below EcoMin.[163]

There are two categories of *price-setting* supply: dispatchable native supply and priced imports.

- **Dispatchable native supply** is energy from generators, demand response resources (DRRs), and virtual transactions (day-ahead market only) that is dispatched economically (based on its offer price). For generators and DRRs, this is energy delivered at levels within the resource's dispatchable range, above EcoMin. This category of supply is able to participate in price formation.

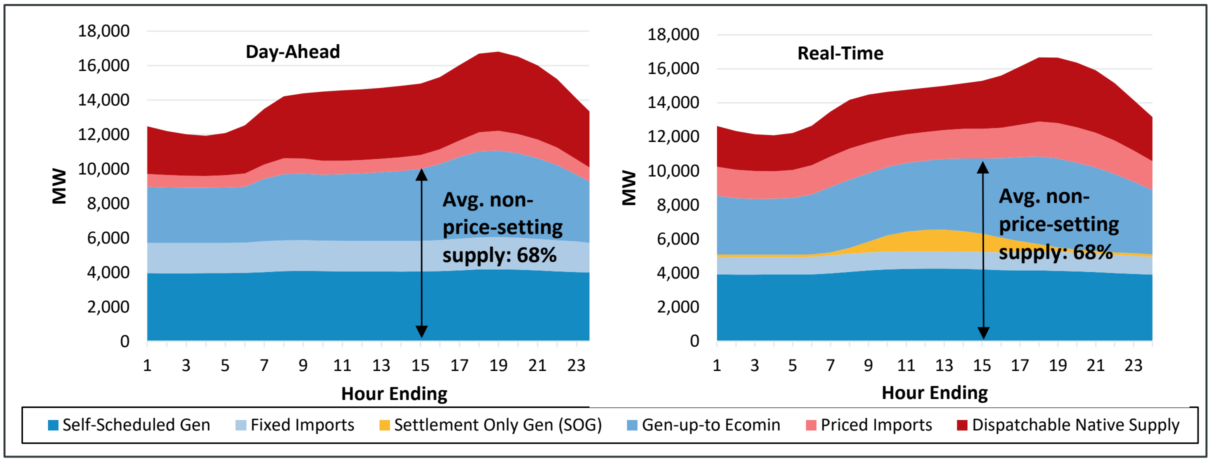
[162] The Economic Minimum (EcoMin) is the minimum MW output available from a generator for economic dispatch.

[163] For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is the portion below 100 MW. Generation-up-to EcoMin does not participate in price formation, as the market software cannot dispatch it up or down.

- **Priced imports** include price-sensitive imports and up-to-congestion transactions.[164, 165] This category of supply is able to participate in price formation.

An hourly average breakdown of price-setting and non-price-setting supply by category for the day-ahead and real-time markets in 2023 is provided in Figure 3-13 below.

Figure 3-13: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2023



On average, non-price-setting supply made up 68% of total supply in the day-ahead and real-time markets, a similar picture to prior few years. Price-setting supply averaged 32% of total supply over all hours in real time in 2023, with its share peaking in hours ending (HE) 18-22 at 35-36%.

In both markets, the daily ramp-ups in load are typically met by additional supply from *generation-up-to EcoMin* and *price-setting* supply. In the day-ahead market, the share of supply from *self-scheduled* generation (the largest component of unpriced supply) and *fixed imports* was reasonably stable over the course of a day. By contrast, in the real-time market, average hourly self-scheduled generation was higher during midday due to output from settlement-only solar generators (SOGs).[166] In 2023, hourly SOG output averaged 496 MW, or 11% of total real-time self-scheduled generation. These smaller generators do not clear in the day-ahead market because they are not modeled in the market nor centrally dispatched by the ISO control room.[167]

---

[164] Up-to-congestion (UTC) transactions are external contracts in the day-ahead energy market that do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are considered willing to pay congestion charges.

[165] There are some nuances to the priced imports category in terms of price-setting ability. While priced imports regularly set price in the day-ahead market, they rarely set price in real-time market. This is because the tie lines are scheduled in advance of the delivery interval in real time and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie lines far away from the scheduled amount determined by the transaction scheduling process.

[166] See Section 1.5 for a discussion on solar generation and changing demand.

[167] SOGs are passive participants in the real-time energy market only.

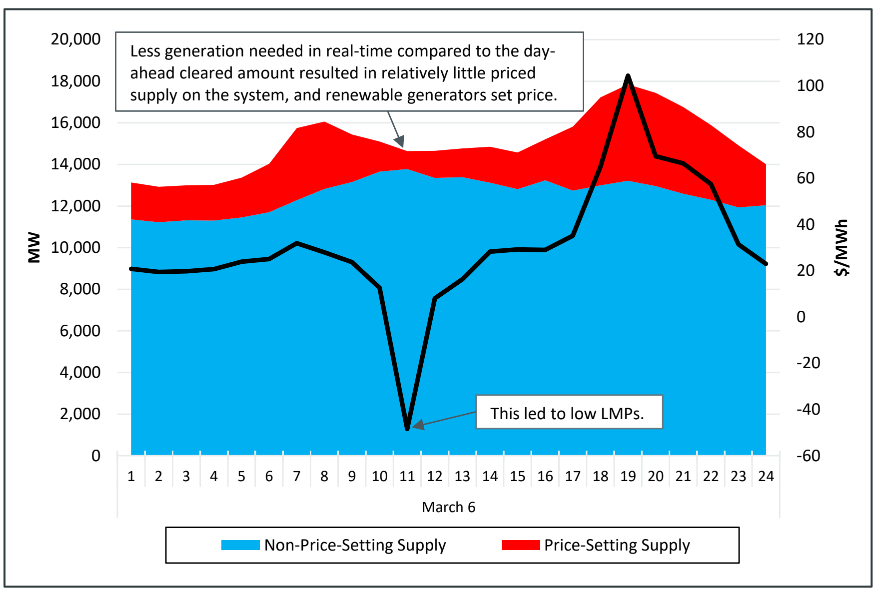
Unpriced Supply and Price Formation Implications

Large volumes of non-price-setting supply can increase the likelihood of low or negative prices. This will become more common when combined with significant amounts of additional capacity from renewable generation (e.g., wind and solar) with low marginal costs. However, we generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand. Further, as more low marginal cost generation participates in the wholesale market, one would expect to see a market response in terms of more price-responsive supply, as otherwise there is a higher risk of energy prices not covering short-run production costs.

The combination of lower loads and large amounts of non-price-setting generation can bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.3% of five-minute real-time pricing intervals in 2023, and in 0.5% of intervals in 2022. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the zonal price was negative in only 0.4% of five-minute real-time pricing intervals in 2023 and 0.5% of intervals in 2022.

The example shown in Figure 3-14 below illustrates negative pricing at a time when a significant amount of non-price-setting supply combined with negative energy supply offers to result in negative LMPs.[168]

Figure 3-14: Priced and Unpriced Supply vs. Real-Time LMP, March 6, 2023



In the midday hours of March 6, real-time loads were relatively low and came in about 700 MW under than the forecast. As a result, real-time generation needs were less than the amount that cleared in the day-ahead market, and the ISO only had to dispatch a small amount of price-setting generation. The small amount of economically dispatched generation offered into the market at negative values, resulting in negative prices. The five-minute Hub LMP ranged from -

[168] Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

$149.53 to -$0.09/MWh from 10:20am to 11:10am, and the hourly price averaged -$48.43/MWh during HE 11.

3.3 Demand-side Factors

The impact of weather and behind-the-meter solar generation on load levels, and the nature of demand-side participation are examined below.

> ***Key Takeaways***
>
> Average and peak load levels (13,096 MW and 24,016 MW, resp.) were the lowest in years, down by 4% and 3%, respectively, from 2022 levels, consistent with mild summer and winter weather. Load also fell on a weather-normalized basis due to growth in behind-the-meter (BTM) solar generation. BTM solar significantly impacted load curves and daily energy prices in all seasons of 2023.
>
> Average day-ahead cleared demand increased to 102.3% of real-time load, driven by a rise in virtual demand. Overall, physical bid-in demand continued to be insensitive to prices; fixed-priced bids remained the most significant category of demand bids. Virtual demand, exports and asset-related demand continue to provide important price-elasticity to the demand side.

3.3.1 Load and Weather Conditions

Net Energy for Load (NEL) averaged 13,096 MW per hour in 2023, 4% below 2022 average load and reaching five-year lows. New England's native load is shown in Table 3-3 below.[169, 170]

Table 3-3: Average, Peak and Weather-Normalized Load

Demand (MW)	2019	2020	2021	2022	2023	% Change '23 to '22	Sparkline
Load (avg. hourly)	13,611	13,305	13,560	13,576	13,096	-4%	
Weather-normalized load (avg. hourly)	13,558	13,242	13,419	13,514	13,132	-3%	
Peak load (MW)	24,361	25,121	25,801	24,780	24,016	-3%	

Observed loads were below weather-normalized levels in 2023, indicating mild weather conditions that decreased load throughout the year. Peak load occurred on September 7, 2023 at 24,016 MW during heat wave conditions, following relatively mild summer weather and setting the lowest peak load since 2017. Weather-normalized load declined in 2023, consistent with the long-term trend of declining loads due to increased energy efficiency and behind-the-meter solar generation. Average load is forecasted to increase within the next few years driven

[169] In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped-storage demand.

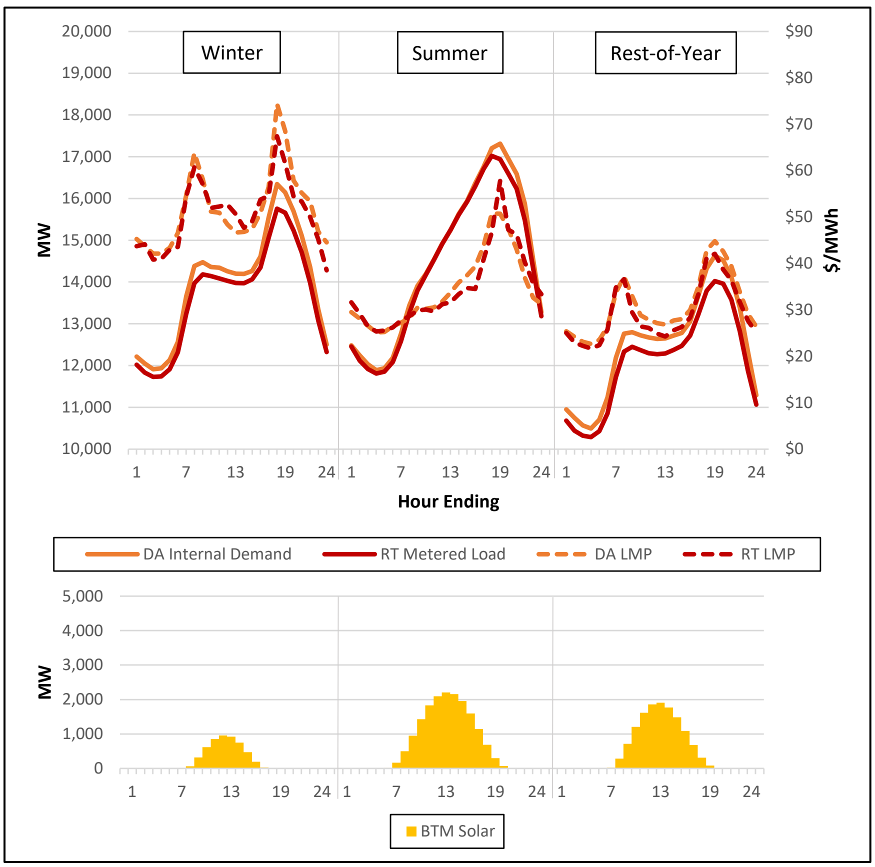
[170] Weather-normalized load estimates what load would be if monthly total heating degree days and cooling degree days were in line with historical averages. The estimate also factors in differences due to non-holiday weekdays and leap days.

by the electrification of heating and transportation, however load forecasting is challenging given the uncertain pace of adoption as well as retail solar growth.[171]

Demand Profiles and Energy Prices

The connection between energy prices and load is particularly evident over the course of the operating day. Figure 3-15 below depicts the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs, along with average hourly load reductions from behind-the-meter (BTM) solar generation. The figure is broken out into winter, summer, and rest of year averages by hour to illustrate seasonal differences in load curves, prices, and solar generation.[172]

Figure 3-15: Average Demand and LMP by Hour, 2023[173]



[171] For more information on electrification growth, see the ISO's *2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 1, 2023), available at https://www.iso-ne.com/system-planning/system-plans-studies/celt

[172] Winter seasons include December, January, and February; summer seasons include June, July, and August.

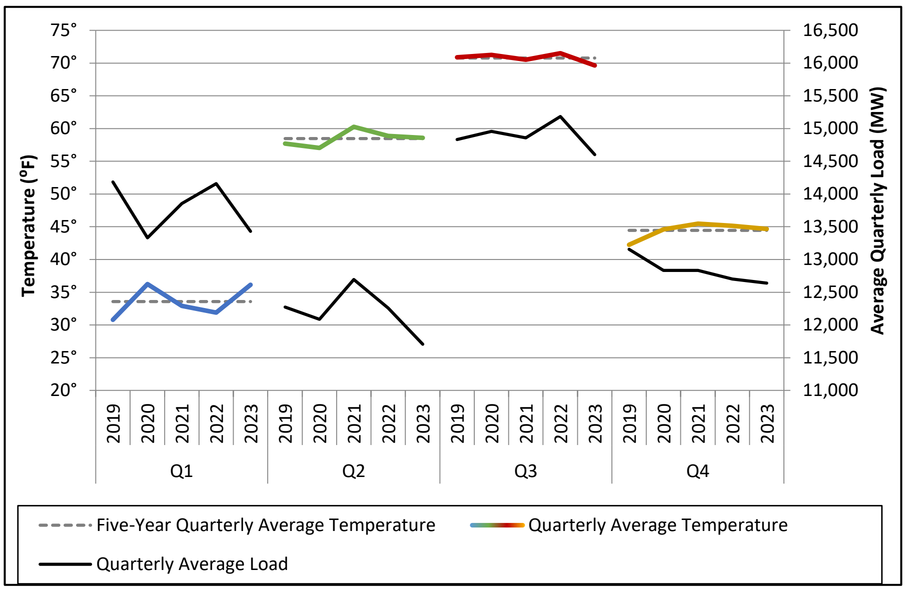
[173] Day-ahead internal demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped-storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

Winter load curves in 2023 typically declined slightly mid-day as solar generation peaked, with approximately 956 MW of BTM generation on average at noon.[174] The highest average day-ahead and real-time LMPs occurred in winter months during evening peak demand periods. Summer months saw the highest average loads, reaching 17,019 MW on average at peak. While summer load curves generally increase steeply throughout the day, solar generation played a significant role in reducing loads during morning ramps, with up to approximately 2,200 MW of BTM generation. Load curves during the rest of the year also exhibited slight mid-day declines as solar generation came online. In all seasons, day-ahead and real-time prices generally followed daily load profiles. Figure 3-15 also shows that day-ahead cleared demand typically exceeded real-time load in 2023 as discussed further in Section 3.3.2.

Impact of Weather

Weather is a significant driver of load in New England. Loads are driven by air conditioning demand in hot weather and electric heating demand in cold weather. Quarterly average and five-year average temperatures for 2019 through 2023 are illustrated in Figure 3-16 below.[175]

Figure 3-16: Seasonal vs. Five-Year Average Temperatures



Loads declined in all quarters of 2023 relative to 2022, driven by mild weather conditions in both winter (Q1) and summer (Q3) along with increased behind-the-meter solar generation. Q1 temperatures averaged 36^{0}F, and Q1 average loads (13,429 MW) fell 5% from 2022. Q3 temperatures averaged 70^{0}F, down from 72^{0}F in 2022. The reduction in air conditioning

[174] The ISO does not meter output from BTM solar installations or directly measure behind-the-meter capacity. For details on behind-the-meter estimation methods, See ISO-NE System Planning's *Load Forecast* page, available at https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Behind-the-Meter%20Photovoltaic%20Data%20Supporting%20Documents&document-type=Hourly%20Behind-the-Meter%20Photovoltaic%20Data

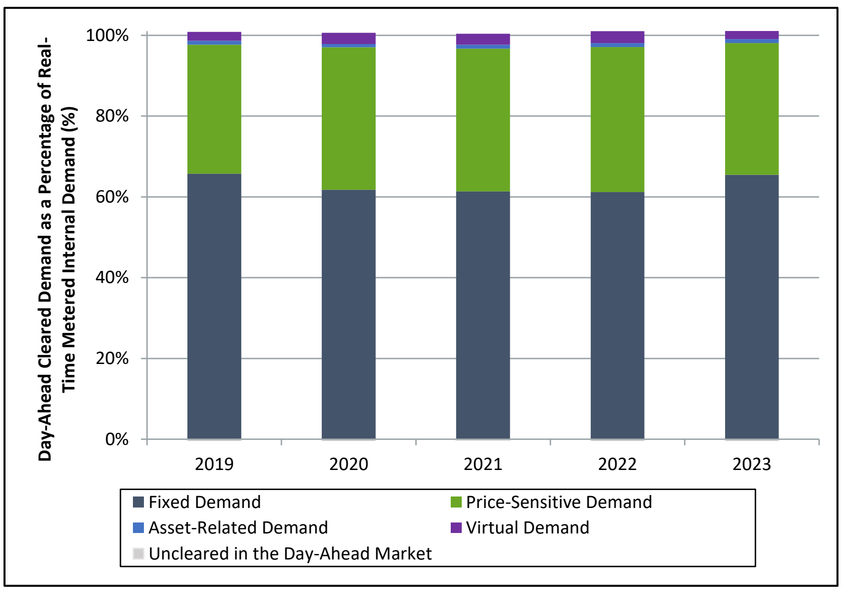
[175] As of July 27, 2023, the ISO calculates New England average temperatures based on new methodology and data collection that incorporates observations from 23 cities. See ISO Newswire's *ISO-NE weather forecast improvements aid grid operations* article (July 27, 2023), available at https://isonewswire.com/2023/07/27/iso-ne-weather-forecast-improvements-aid-grid-operations/

demand resulted in average loads of 14,601 MW, down 4% from 2022. While milder weather during peak seasons contributed to lower loads in 2023, loads fell even in shoulder seasons (Q2 and Q4) despite similar weather to prior years as a result of behind-the-meter solar and energy efficiency growth.

3.3.2 Demand Bidding

The quantity and pricing of bid-in demand in the day-ahead market has important price formation and operational implications. For example, generator commitments for the operating day are determined by the clearing process that matches supply and demand at least cost, which impacts the ISO's reserve adequacy analysis (RAA).[176] Furthermore, demand bids can also set price; demand set price for 22% of load in the day-ahead market (mainly comprising virtual demand and exports), and asset-related demand set price for 4% of load in the real-time market.[177] Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 3-17.[178]

Figure 3-17: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type



Participants cleared 102.3% of real-time load in the day-ahead market, up from 101.0% in 2022 and the highest over the reporting period. The increase in over-clearing in the day-ahead market is largely attributable to an increase in virtual demand, which rose to 3.3% of real-time load from 2.9% in 2022. Virtual demand increased as participants cleared more decrement bids at external nodes, as discussed in Section 5. Participants cleared 65.4% of real-time demand as fixed day-ahead bids, and 32.6% as priced day-ahead bids. Asset-related demand clearing, primarily composed of pumped-storage demand, remained constant year-over-year.

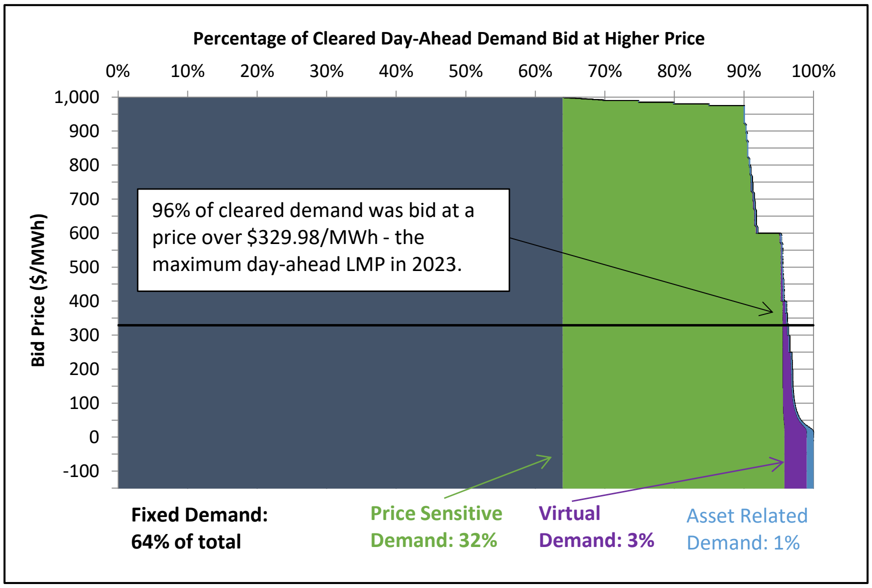
[176] The reserve adequacy analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available at least cost to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. For more information, see Section 3.4.

[177] See Section 3.3.2 for a discussion of marginal resources and price-setting load.

[178] Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.

Aggregating cleared demand components by price provides additional insight into bidding behavior and the price sensitivity of demand. Figure 3-18 aggregates annual cleared demand by bid price.

Figure 3-18: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Internal demand in New England continued to be primarily price insensitive. Nearly two-thirds of total day-ahead cleared demand was bid as fixed demand. Price-sensitive demand bids account for 32% of all day-ahead cleared demand, but frequently clear with bid prices well above expected LMPs. Virtual demand and price-sensitive pumped-storage demand bids often have lower bid prices and account for approximately 4% of cleared demand bids. In total, the aggregate internal demand curve is relatively price-insensitive around expected LMPs, limiting any concerns of monopsony market power through demand bidding.

3.4 System Reliability

The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[179] To meet reliability standard requirements, the ISO may commit additional resources required to meet the real-time operating plan, to supplement capacity availability in constrained areas, to provide voltage protection, and to support local distribution networks. The ISO also might manually constrain (posture) resources to maintain adequate operating reserves. This typically occurs through limiting output from fast-start, pumped-storage generators during prolonged, tight market conditions.

[179] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. More information on the NERC standards available at http://www.nerc.com/pa/stand/Pages/default.aspx. More information on the NPCC standards and criteria available at https://www.npcc.org/program-areas/standards-and-criteria. More information on the ISO's operating procedures available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

Key Takeaways

In 2023, the day-ahead market generally secured enough physical supply to meet the anticipated real-time load, resulting in reduced reliance, by the reserve adequacy analysis (RAA), on suppliers to exceed their day-ahead energy allocations. This trend corresponds with day-ahead demand findings, where, on average, load-serving entities in 2023 cleared more demand in the day-ahead market than was actually consumed in real time.

Overall, reliability commitment costs remain a very small proportion of overall energy costs, which is consistent with transmission grid investments in recent years that have lessened the need for local second contingency and voltage commitments. There has also been a significant decrease in reliability commitments and posturing over the past five years.

In 2023, load forecast error and volatility generally increased compared to 2022 because of relatively low loads combined with the challenges of forecasting increasing levels of behind-the-meter (BTM) solar. This has important implications for price convergence between the day-ahead and real-time markets; for example, lower real-time load due to higher than anticipated BTM solar output, leads to the most expensive generation been dispatched down, and lower real-time prices compared to day-ahead prices (and vice versa).

3.4.1 Reserve Adequacy Analysis and the Day-Ahead Energy Gap

The commitment, dispatch and pricing outcomes in the financial day-ahead market may not always reflect expected *physical* real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than will be needed in real time. When this happens, ISO-NE must ensure there is sufficient energy and reserve capability to meet forecasted real-time load and reserve requirements.

To that end, after the day-ahead market, the ISO performs the Reserve Adequacy Analysis (RAA) to evaluate day-ahead cleared supply against these forecasted energy and reserve requirements. If the day-ahead market did not clear enough *physical* supply to meet the ISO's forecasted demand and reserve requirements, the RAA may rely upon resources to operate at levels above their day-ahead schedules and, infrequently, may require additional generator commitments.[180]

We define the day-ahead energy gap as the difference between the amount of physical cleared generation (i.e., excluding virtual supply) in the day-ahead market and the expected real-time load. Statistics on the value of the energy gap for the last five years is shown as a box plot in Figure 3-19.[181, 182] The figure also includes the average energy quantity from physical suppliers

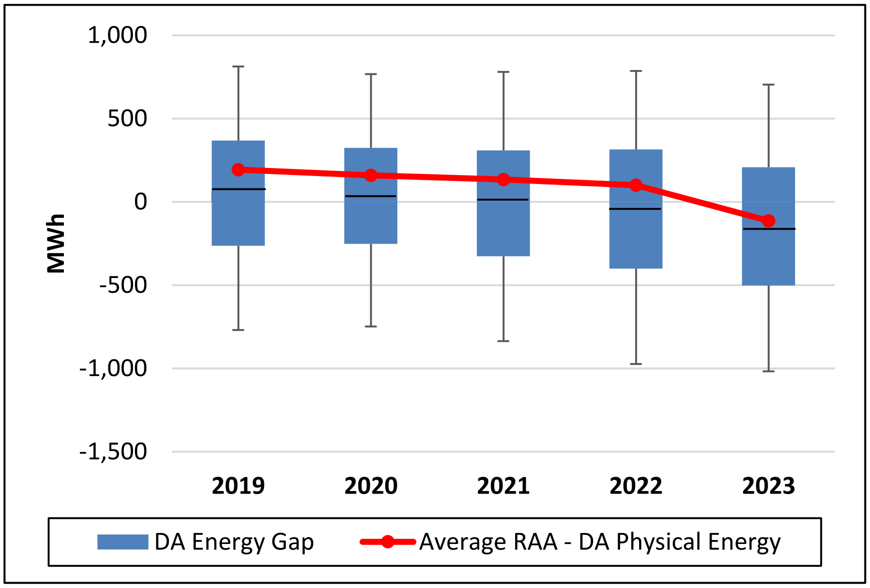
[180] One such commitment occurred in 2023. A ~340 MW resource was committed by the RAA process for a five-hour period on October 22, 2023.

[181] The box plot shows the 25th and 75th percentiles (interquartile range), the median (50th percentile), along with the more extreme observations at the 5th and 95th percentiles.

[182] The Day-Ahead Ancillary Services Initiative (see Section 9) proposes to incorporate the load forecast into the day-ahead market's commitment, clearing, and pricing processes, thereby resolving any non-negative day-ahead energy gaps through a market mechanism rather than the out-of-market RAA process.

relied upon by the RAA in excess of those suppliers' day-ahead energy awards.[183] For instance, suppose 12,000 MW of physical supply clears energy awards in the day-ahead market, and the RAA needs to satisfy a load forecast of 12,050 MW in that same hour. In this hour, the RAA relies upon 50 MW of physical supply to operate at levels above what cleared in the day-ahead market.

Figure 3-19: Day-Ahead Energy Gap and RAA Reliance on Supply above Day-Ahead Award



When the energy gap is greater than zero, the RAA process relies upon generation to operate above DA energy awards to meet expected real-time load. While the magnitude of the day-ahead energy gap can vary, the median value is close to zero and this value has decreased over time. As a result, the reliance of the RAA process on resources to operate at levels above their DA energy awards has also decreased. The negative value shown in 2023 (red line) indicates that in 2023 the day-ahead market typically procured sufficient physical supply to meet expected real-time load, and the RAA was therefore less frequently reliant on suppliers to operate above their day-ahead energy awards. This outcome aligns with observations on day-ahead demand participation; on average in 2023, load-serving entities cleared more demand in the day-ahead market than what they consumed in the real time.[184]

3.4.2 Reliability Commitments and Posturing

Out-of-market or unpriced reliability commitments or actions are not met through the markets, while often necessary, can have negative implications for market price formation and incentives.

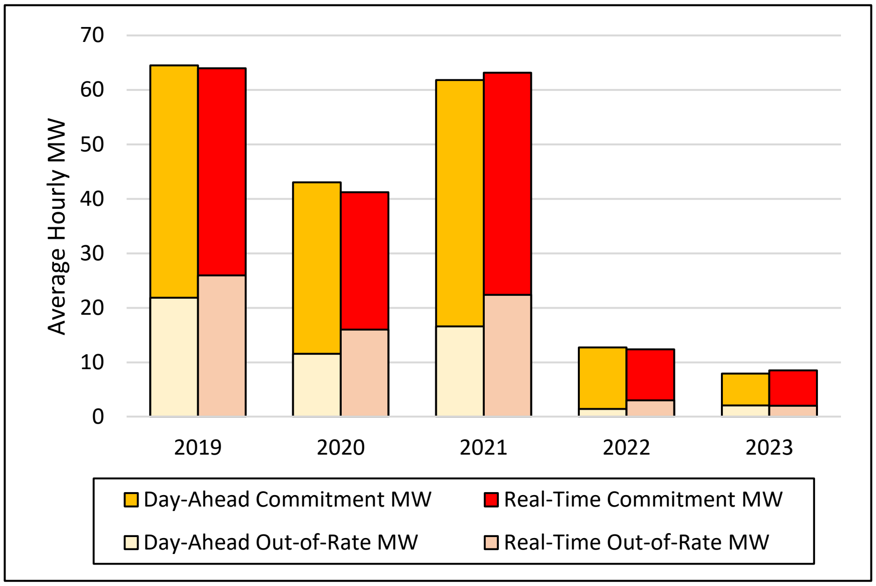
[183] In prior years, this figure has shown the quantity of supplemental commitments resulting from the RAA. We modified this figure to instead quantify the RAA's reliance upon suppliers to operate above day-ahead energy awards, because such reliance is commonplace, while RAA commitments are infrequent.

[184] See Section 3.3 for more information on high levels of demand clearing in the day-ahead market.

Reliability Commitments

Average hourly energy output (MW) from reliability commitments for 2019 through 2023 is shown in Figure 3-20 below.[185] The figure also specifies which portion of the output was out-of-rate, based on offer segments priced above the LMP.

Figure 3-20: Average Hourly Energy Output from Reliability Commitments



In 2023, generation associated with reliability commitments totaled roughly 8 MW of average hourly output in both day ahead and real time, with 2 MW being out-of-rate. Reliability commitments have decreased significantly over the past two years as transmission upgrades in Maine and Southeastern Massachusetts (SEMA) were completed. Overall, reliability commitment costs remain a very small proportion of overall energy costs, which is consistent with transmission grid investments in recent years that have lessened the need for local second contingency and voltage commitments.

Over the reporting period, the vast majority (96%) of day-ahead reliability commitments were made for local second contingency protection reliability (LSCPR), while the remaining commitments were for voltage support (3%) and first contingency reliability (1%).[186] In the real-time market, LSCPR commitments made up 92% of reliability commitments, while the remaining commitments were for special-constraint resources (3%), voltage support (3%), dual-fuel resource audits (2%), and first contingency reliability (1%).

[185] Reliability commitments include local first contingency, local second contingency, voltage, distribution, and dual-fuel auditing commitments. For more information on reliability commitments reviewed by the IMM, see *Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf

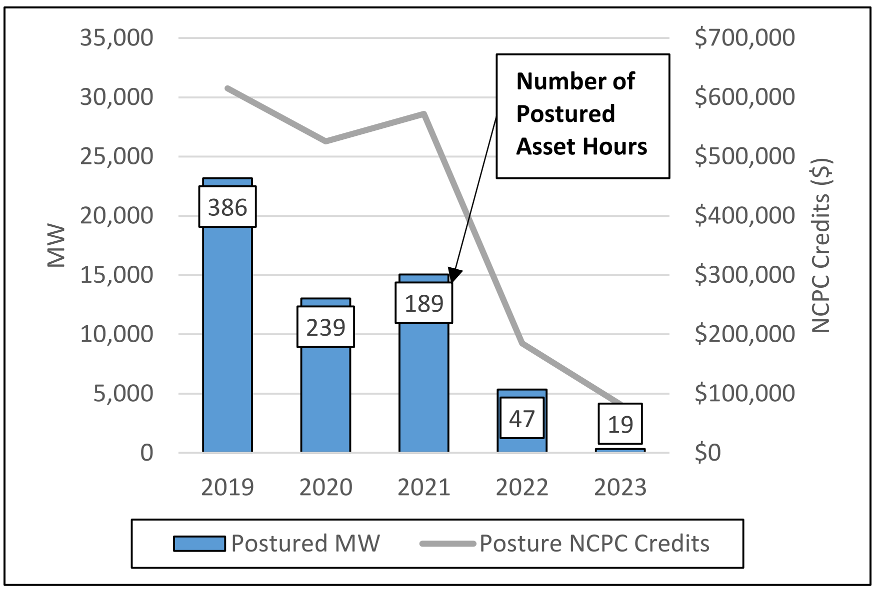
[186] Local second contingency protection reliability (LSCPR) commitments are made for import-constrained areas, if necessary, to ensure that the ISO can re-dispatch the system to withstand a second contingency loss within 30 minutes after the first contingency loss without exceeding transmission element operating limits.

Posturing Actions

Posturing generators results in the preservation of fuel for "limited energy" generators in the event of system contingencies. A generator may provide operating reserves while postured, but is only available for manual dispatch above the posturing level in the event of a system contingency. Postured generators are eligible to receive NCPC for any foregone profits that occurred during the posturing period.[187]

Postured energy (MWh) and NCPC payments from 2019 to 2023 are shown in Figure 3-21 below.[188] The blue bars (left axis) indicate the postured energy obtained (the amount of energy constrained down) from pumped-storage generators and the gray line (right axis) indicates the amount of NCPC credits paid to pumped-storage generators for foregone revenue.[189]

Figure 3-21: Annual Postured Energy and NCPC Payments



Pumped-storage generator posturing has decreased significantly over the reporting period. In 2023, only 19 asset hours of posturing occurred for a total 336 MW, marking the lowest totals in the reporting period. The decrease in posturing follows the same downward trend as reliability commitments, demonstrating a lesser need for ISO New England operators to rely on manual commitments to retain system-wide reliability.

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[187] See ISO's Market Rule 1, *Section III Market Rule I Appendix F Net Commitment Period Compensation*, Sections 2.3.8 and 2.3.9, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_f.pdf

[188] Postured energy is the amount of energy that is unavailable for economic dispatch. This value is used in the settlement compensation for the posturing action.

[189] Very infrequently, pumped-storage demand (or asset-related demand) is postured. These resources are postured on-line (in consumption mode) to increase operating reserves. The energy associated with these posturing activities is not depicted in the figure. Fossil fuel-fired generation can also be postured but this did not occur during the reporting period.

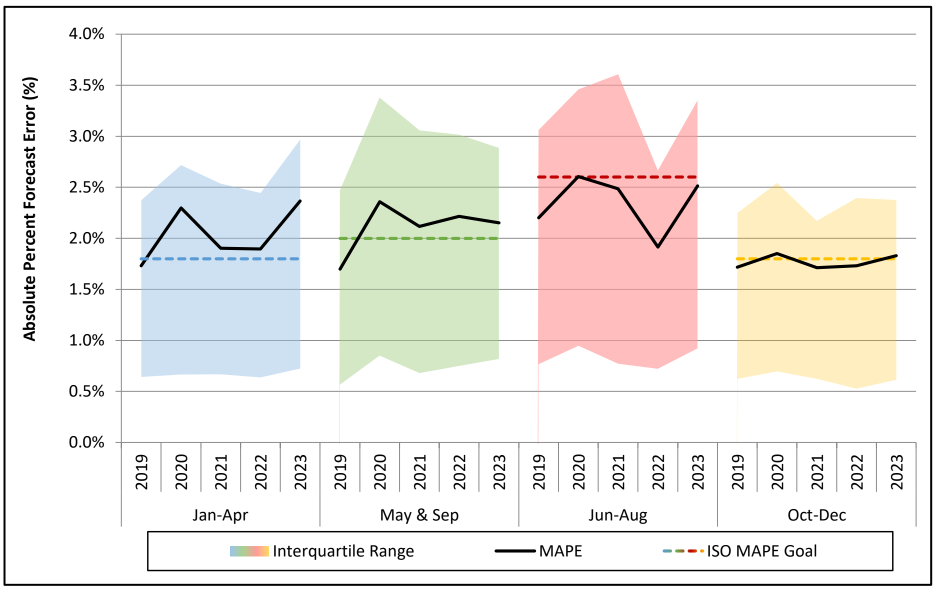
3.4.3 Load Forecast and Market Implications

The ISO publishes a day-ahead load forecast around 9:30AM as the last load projection prior to the close of the day-ahead market for the next operating day.[190] While the ISO forecast is not a direct input into the day-ahead market, its publication provides transparency into operational planning and is often referenced by participants submitting day-ahead demand bids.[191, 192] Load forecast error can influence day-ahead and real-time price deviations through guiding participant day-ahead clearing, as units might be committed or backed down in merit order to meet real-time load deviations.

Load Forecast Accuracy

Real-time conditions such as weather variations and behind-the-meter solar output can contribute to load forecast error.[193] The mean absolute percent error (MAPE) of the ISO's day-ahead load forecast by time of year is shown in Figure 3-22 below. Months are partitioned into four groups based on the ISO's monthly load forecast goal.[194]

Figure 3-22: ISO Day-Ahead Load Forecast Error by Time of Year



[190] Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. See ISO's *Three-Day System Demand Forecast* page, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast

[191] Load Serving Entities (LSEs) may also rely on their own in-house or third party forecasting tools to inform their day-ahead bidding strategy.

[192] Additionally, as mentioned in Section 3.4, the load forecast is used in the RAA process to finalize the ISO's next day operating plan.

[193] The ISO has revised load-forecasting goals to account for growing behind-the-meter solar generation, which increases load forecast error.

[194] The ISO's target MAPE goals during the year are 1.8% in January–April and October–December; 2.0% in May and September, and 2.6% in June–August.

Figure 3-22 shows that 2023 forecast error and volatility generally increased compared to 2022, with errors exceeding goals in three out of the four time periods. Probable causes of increased forecast error include relatively low loads combined with the challenges of forecasting the increasing levels of behind-the-meter solar as a share of load. This has important implications for price convergence between the day-ahead and real-time markets as illustrated below.

The growth in behind-the-meter[195] (BTM) solar generation in recent years adds to the challenge of forecasting load.[196] Figure 3-23 shows the relationship between daily average load forecast error and solar forecast error in blue on the left axis, along with the relationship between load forecast error and LMP deviations between day ahead and real time in orange on the right axis. The top-right quadrant captures scenarios where loads are higher than forecasted, BTM Solar is lower than forecasted, and real-time LMPs are higher than day-ahead LMPs, while the bottom-left quadrant captures the opposite scenario.

Figure 3-23: Impact of BTM Solar on Load Forecast Error

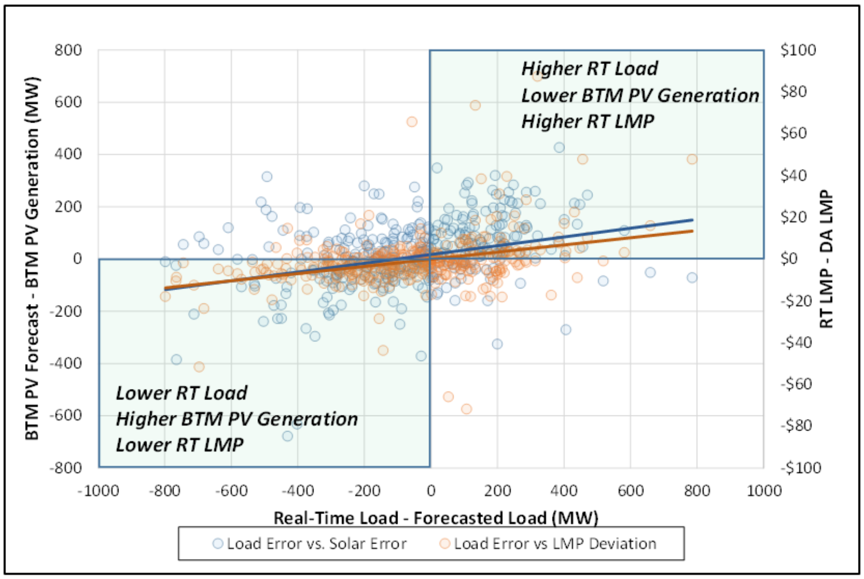


Figure 3-23 shows a statistically meaningful relationship between solar forecast error, load forecast error, and real-time price deviations. Load reductions from expected BTM solar are built into day-ahead load forecasts. If BTM solar generation is lower than forecast in real time, real-time loads are likely to be higher than forecast. Dispatching generation up to meet the higher real-time load frequently increases real-time LMPs relative to day-ahead LMPs. Therefore, BTM solar forecast error has a significant pass-through effect on LMP deviations through shifting real-time load.

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[195] With respect to forecasting, the ISO includes settlement-only solar generation or SOGs in the forecasted impact of BTM solar generation.

[196] In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see ESIG's article *Building data intelligence for short-term load forecasting with behind-the-meter PV,* by Jon Black, (March 27, 2019), available at https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/

3.5 Net Commitment Period Compensation (Uplift)

NCPC are make-whole payments made to generators, external transactions, and virtual transactions when they follow ISO dispatch instructions and experience revenue shortfalls or lost opportunity costs. NCPC payments can provide insight into unpriced energy costs, and higher levels of uplift may be symptomatic of price formation or missing product issues. In this section, we review NCPC in the context of total energy payments, provide a breakdown of payments by category, and show NCPC payments by generator type.

> ***Key Takeaways***
>
> NCPC totaled $34.4 million ($0.30/MWh of load) in 2023, down 35% from 2022 as energy market payments fell year-over-year. NCPC made up 0.7% of energy market payments, up slightly from 0.5% in 2022. The increase in NCPC as a share of energy market payments was driven by payments to fast-start out-of-merit generators in late 2023. This increased during prolonged scheduled outages of fast-start generation as relatively costly oil-fired generators were committed during tight system conditions.
>
> The vast majority of NCPC payments in 2023 (93%) were paid to cover the operating costs of resources committed in economic merit order to meet load and reserve requirements. Payments for local second contingency protection totaled $0.7 million, down 39% from 2022, consistent with the decline in output (36%) from local reliability commitments.

NCPC in the context of the energy market payments

Tracking NCPC payments relative to energy payments provides a high-level metric capturing reliance on compensation through side make-whole payments rather than uniform market clearing prices, as well as the level of costs borne by payers of uplift, which can be difficult to predict and hedge. Energy and NCPC payments are summarized in Table 3-4 below.

Table 3-4: Energy and Uplift Payments

	2019	2020	2021	2022	2023
Energy Payments ($ millions)	$4,105	$2,996	$6,099	$11,699	$4,847
NCPC Payments ($ millions)	$30.60	$25.95	$35.94	$53.08	$34.36
NCPC in $/MWh	$0.26	$0.22	$0.30	$0.45	$0.30

NCPC as % Energy Payments					
Day-Ahead NCPC	0.3%	0.3%	0.3%	0.1%	0.1%
Real-Time NCPC	0.4%	0.5%	0.3%	0.3%	0.6%
Total NCPC as % Energy Costs	**0.7%**	**0.9%**	**0.6%**	**0.5%**	**0.7%**

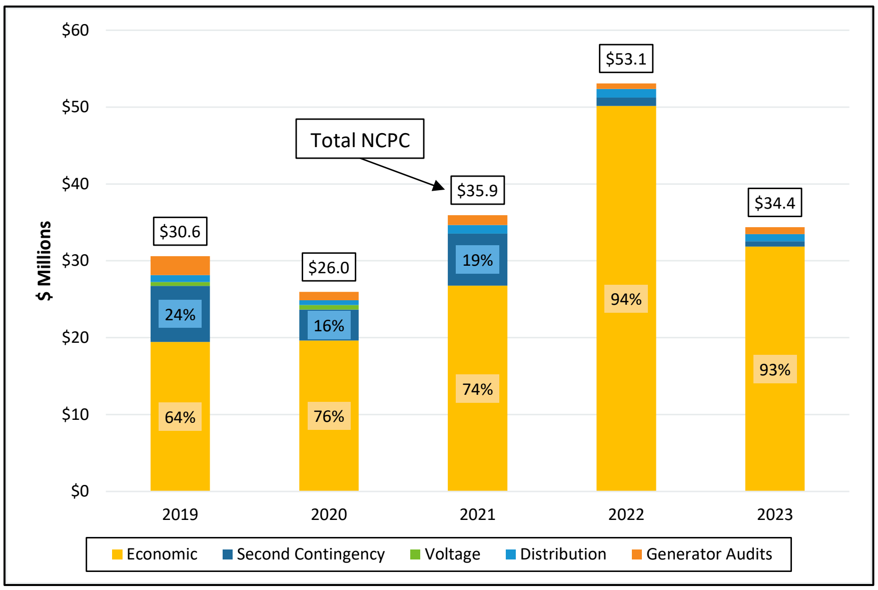
NCPC payments totaled $34.36 million in 2023, down 35% from 2022, consistent with a 59% year-over-year decline in energy market payments. While total NCPC and payments per MWh of load fell, NCPC as a share of energy market payments rose to 0.7%, reflecting significant uplift payments to fast-start resources in late 2023. Real-time uplift continued to comprise the majority of NCPC at 86% of payments.

It is also important to note that payments under the Mystic Cost Of Service (CoS) agreement are also a form of uplift payments to compensate generators outside of the capacity market for providing fuel security reliability services. These costs were more than ten times higher than energy uplift payments, at $460 million, or $4/MWh of load.

NCPC Payments by Category

NCPC payments are sorted into categories based on the underlying driver of the commitment or dispatch decision, including: meeting system-wide first-contingency requirements (economic NCPC), local second-contingency, distribution or voltage requirements, and dual-fuel auditing requirements. Annual NCPC by category is shown in Figure 3-24 below.

Figure 3-24: Total Uplift Payments by Year and Category

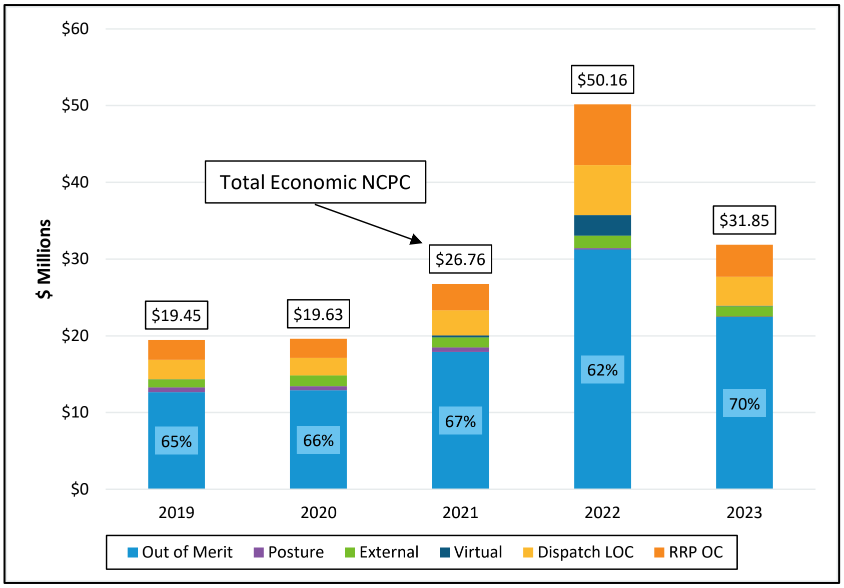


Economic (or First Contingency) NCPC comprised the largest share (93%) of annual NCPC payments at $31.85 million. Economic NCPC fell 36% from 2022 following a 59% decline in energy market payments. Second contingency (LSCPR) payments fell 39% to $0.7 million, following a proportional 36% decline in output associated with local second contingency commitments. The majority of LSCPR payments (86%) occurred in Q1, but overall LSCPR commitments and uplift declined significantly in 2023 as discussed in Section 3.4.2. All other NCPC categories remained similar to prior years.

Economic NCPC by Subtype

Economic NCPC payments contain sub-categories, including out-of-merit payments for unrecovered generation costs, posturing uplift, external transaction payments, and compensation for lost opportunity costs due to the dispatch or rapid-response pricing process. Economic NCPC by subtype is shown in Figure 3-25 below.

Figure 3-25: Economic Uplift by Sub-Category



Out of merit payments, which cover any revenue shortfalls of generators committed to meet load and reserve requirements, comprised the largest share of economic NCPC at $22.4 million. Out of merit payments fell 28% from 2022 ($31.2 million), but rose as a share of total economic NCPC (70%). An outsized share (46%) of out of merit payments occurred in Q4, when flexible fast-start pumped-storage generators were out of service and relatively expensive oil-fired fast-start generation was frequently committed out-of-merit for reliability needs.[197]

The two largest forms of opportunity cost payments (dispatch opportunity and rapid-response opportunity costs) declined by 45% (to $4.2 million) in line with lower energy prices, together comprising a similar share to prior years (25%). Payments to external transactions ($1.3 million) were in-line with prior years, while uplift to virtual transactions fell to the lowest level since 2019 in 2023.[198] There were few posturing uplift payments in 2023, continuing a downward trend since 2019 as the frequency of generator posturing declined.[199]

NCPC by Generator Type

NCPC can be disaggregated by generator type to illustrate typical out-of-market uplift for various generator classes. Average payments per MWh of generation illustrate the typical out-of-market costs of different generator types, and provide context for total NCPC payments. Figure 3-26 below shows total NCPC payments by year and fuel type for select generator categories, with an inset table showing NCPC payments per MWh of generation.[200]

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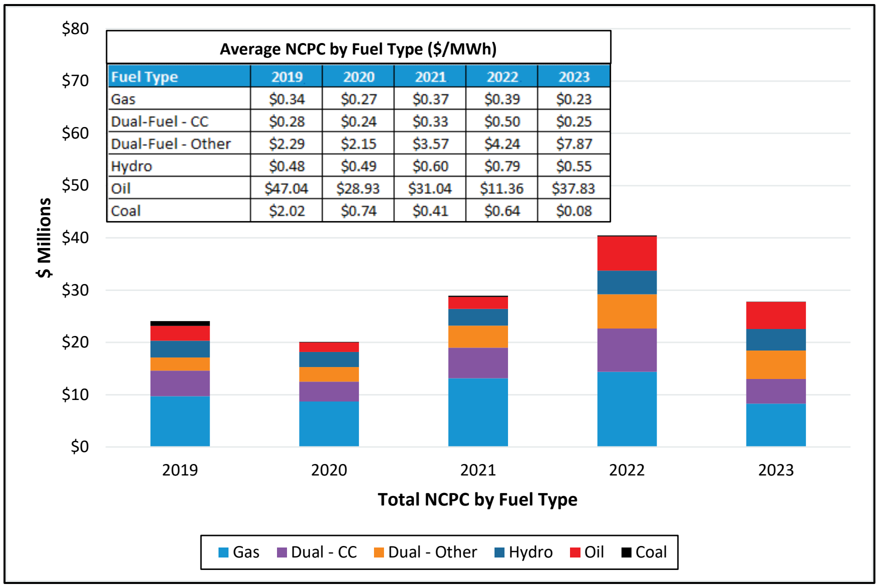
[197] For a detailed discussion of fast-start NCPC in late 2023, See our *Fall 2023 Quarterly Markets Report* (January 24, 2024), p.26, available at https://www.iso-ne.com/static-assets/documents/100007/2023-fall-quarterly-markets-report.pdf

[198] See Section 4.1.3 for an explanation of drivers of uplift to both external and virtual transactions.

[199] See Section 3.4.2 for a detailed discussion of posturing actions.

[200] Average NCPC by fuel type is calculated as the sum of annual NCPC payments to generators of a given fuel type divided by the total annual generation produced by generators of that fuel type.

Figure 3-26: NCPC by Generator Fuel Type



Average NCPC by Fuel Type ($/MWh)

Fuel Type	2019	2020	2021	2022	2023
Gas	$0.34	$0.27	$0.37	$0.39	$0.23
Dual-Fuel - CC	$0.28	$0.24	$0.33	$0.50	$0.25
Dual-Fuel - Other	$2.29	$2.15	$3.57	$4.24	$7.87
Hydro	$0.48	$0.49	$0.60	$0.79	$0.55
Oil	$47.04	$28.93	$31.04	$11.36	$37.83
Coal	$2.02	$0.74	$0.41	$0.64	$0.08

Single-fuel gas-fired generators received more NCPC than any other generator category in 2023 at $8.3 million, while uplift per MWh of gas generation remained low at $0.23/MWh. Dual-fuel combined-cycle generators similarly received $0.25/MWh of generation. Low payments per MWh of generation indicate that the operating costs of such units were frequently supported by LMPs. Payments to hydro resources remained low, while coal fell significantly in 2023 due to very infrequent coal generation.

Payments to dual-fuel generators (simple cycle gas and steam turbines) and oil (single fuel) generators received higher NCPC payments at $5.4 million ($7.87/MWh) and $5.2 million ($37.83/MWh), respectively. Such units were typically only committed in real time as fast-start generation, and received uplift when they were committed but not setting price or otherwise recovering operating costs through market prices.[201] The increase in total NCPC as a share of energy market value in 2023 is largely attributable to these payments, which increased in late 2023 as a result of prolonged pumped-storage generator maintenance and tight reserve margins.[202]

3.6 Summary of System Events During 2023

System events, such as tight system conditions resulting from generator outages or load forecast error, can have a significant impact on energy market outcomes. Two events occurred in 2023 that bear specific mention: the February 3-4 cold snap and the July 5 capacity deficiency (shortage event). This section details the frequency of system events and abnormal conditions over the past five years, and then provides a summary of the February 3-4 and July 5 events.

[201] Fast-start pricing mechanics are designed to reduce commitment uplift through reflecting commitment costs in offer prices for fast-start units. Under these mechanics, commitment payments have fallen during periods when fast-start units set price, but remain in periods where fast-start units do not set price and LMPs fail to cover their commitment costs.

[202] Pumped-storage generators typically fill system needs for fast-start resources, resulting in a shift to costly fast-start oil generation during these outages.

Key Takeaways

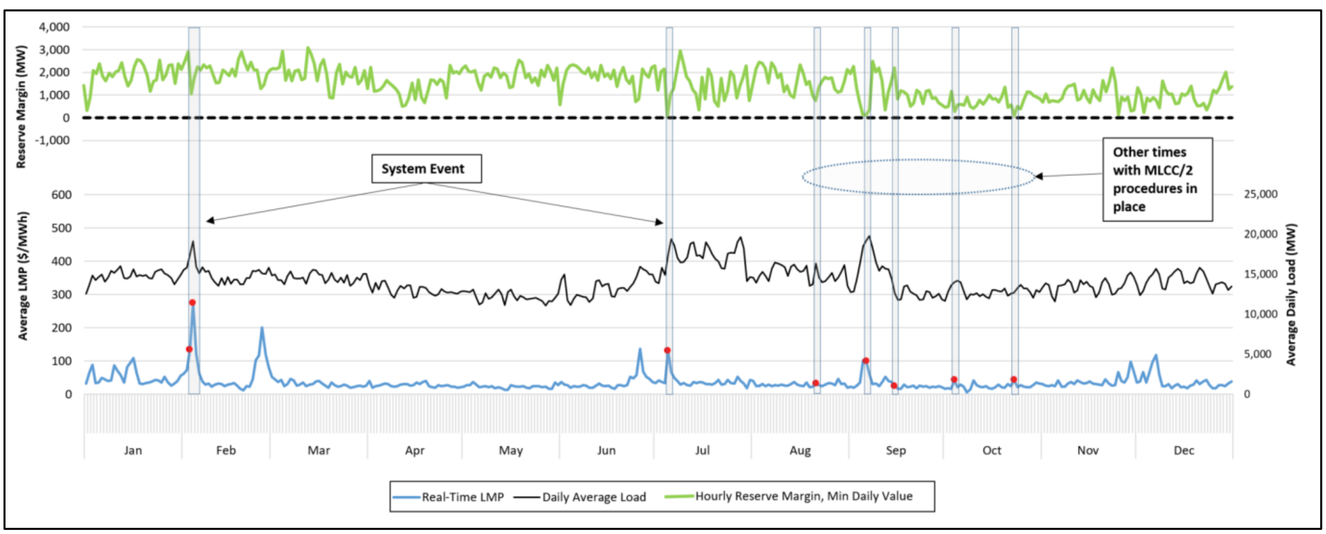
Weather and unplanned outages were the main drivers behind notable system events over the last several years. While there have been no sustained winter cold spells since Winter 2018, two notable days in February 2023 highlighted the impact of cold weather on natural gas and energy prices. Unplanned generator outages generally occurred due to mechanical issues rather than problems procuring fuel. The availability of Phase II, whether mechanical or weather related, also played a significant role in system events over the past few years.

One shortage event and six M/LCC 2 events occurred during 2023. The shortage event (i.e., capacity scarcity conditions) lasted just 30 minutes on July 5, when the Phase II interconnection with Quebec tripped and caused an unexpected reduction in net imports during the evening peak. Though there were no M/LCC 2 events during the winter months, a short cold snap led to high natural gas prices and LMPs on February 3 and 4. The highest hourly real-time Hub LMP in 2023 ($1,162/MWh) occurred during the July 5 shortage event.

Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years.

To provide context for the events covered in this section, the graph below overlays the timing of the two events discussed above and M/LCC2 events on a series of daily real-time LMPs and load levels. Also shown is the minimum total reserve margin (for an hour) for each day.

Figure 3-27: Pricing, Demand and the Reserve Margin during System Events in 2023



The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years:

- Number of OP-4 and M/LCC 2 Events
- Reserve Deficiency Events
- Frequency of Extreme Hub LMPs

OP-4 and M/LCC 2 Events

The ISO uses the following established procedures to address issues and alert participants during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)[203]
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)[204]

The number of instances for each type of event during the reporting period is shown in Table 3-5 below.

Table 3-5: OP-4 and M/LCC 2 Event Frequency

	2019	2020	2021	2022	2023
# of OP-4 Events	0	0	0	1	1
# of M/LCC 2 Events	0	3	6	6	6

The ISO implemented six M/LCC 2 events in 2023, the same amount as in 2022 and 2021. In our assessment of the system events, detailed in the quarterly reports, we generally found that the market performed well during these periods. The table at the end of this section summarizes the high-level causes and outcomes of each system event in 2023.

Reserve Deficiency Events

Reserve deficiency events (i.e., periods when there are negative reserve margins) are indicative of stressed system conditions. In these instances, the system generally does not have enough reserve capability to meet the requirements for reserves. As a result of such deficiencies, reserve product clearing prices and energy clearing prices typically reflect the relevant Reserve Constraint Penalty Factors (RCPFs). Below, Table 3-6 shows the number of hours during which each reserve margin was negative.

[203] M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability. See the ISO's *Master/Local Control Center Procedure No. 2 (M/LCC2) Abnormal Conditions Alert*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[204] OP-4 establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure that the ISO can invoke as system conditions worsen. See *ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

Table 3-6: Frequency of Negative Reserve Margins (System Level) [205]

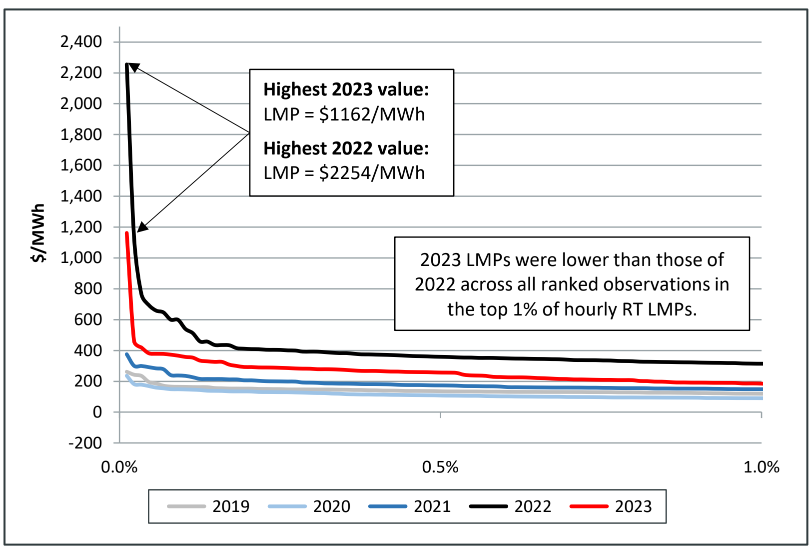
Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative 10 Minute Spinning Reserve Margins
2019	0.0	0.0	25.9
2020	0.0	0.0	14.5
2021	0.0	0.0	26.8
2022	1.4	0.1	48.1
2023	0.5	0.3	6.8

Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years. The Total30 and Total10 margins fell below zero in 2022 and 2023, when tight system conditions led to capacity scarcity events. No comparable events occurred during 2019-2021. Shortages of ten-minute spinning reserves (with an associated RCPF of $50/MWh) were less frequent in 2023 compared to the prior years due to a lower spinning reserve requirement as discussed in Section 7.1. The spinning reserve shortages occurred across 18 days throughout the year in 2023 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages.

Frequency of Extreme Hub LMPs

High real-time LMPs can also indicate stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure 3-28 below show the top 1% of hourly average real-time LMPs ranked from high to low over the past five years.

Figure 3-28: LMP Duration Curves for Top 1% of Real-Time Pricing Hours



[205] The calculations in this table come from the LMP calculation processes in the real-time market software. The "Hours of Negative Total30 Margins" column does not include instances where only the replacement reserve margin is negative, because those instances are not associated with the $1,000/MWh RCPF.

Lower real-time Hub LMPs in 2023 compared to 2022 reflected lower natural gas prices and fewer shortage event hours. The highest hourly price of the year ($1,162/MWh) occurred during HE 19 on July 5, when 30 minutes of capacity scarcity conditions resulted in the RCPFs for the total ten-minute reserve constraint ($1,500/MWh) and total thirty-minute reserve constraint ($1,000/MWh) being incorporated into LMPs for a portion of that hour. Of the top 1% of hourly average real-time Hub LMPs for 2023, 29% occurred on July 5 (shortage event) or February 3-4 (cold snap event). There was also a shortage event in December 2022 that resulted in high LMPs. No comparable events occurred in 2019-2021.

Specific days that saw notable market and system outcomes in 2023 are summarized in Table 3-7 below.

Table 3-7: System Events In 2023

Date	Event Type	Driver	Market and System Summary
Feb 3 – 4	High energy pricing	Cold snap resulting in very high natural gas prices	These two days saw the coldest temperatures (daily lows of -6°F and -10°F, respectively) and highest natural gas prices of the year ($37.47-49.68/MMBtu). Oil-fired generation was in merit and made up a significant portion of the supply stack, and there were fewer real-time imports compared to the day-ahead schedule due to high demand in Canadian provinces.
Jul 5	M/LCC2, OP4 (Actions 1,2), Capacity Shortage Event	Phase II trip due to Forest Fires	A 1,000 MW drop in imports compared to day ahead resulted in operator reliability actions (posturing, curtailing real-time only exports, and manually committing off-line fast-start units). Capacity scarcity conditions (PfP event) for 30 minutes, and 5-minute real-time LMPs peaked at $2,707/MWh.
Aug 21	M/LCC 2	Unplanned generator outages	Multiple unplanned generator outages caused by mechanical issues resulted in tight conditions during the evening peak and operator reliability actions (manually committing off-line fast-start units). Five-minute real-time Hub LMPs peaked at $115/MWh at 17:50.
Sep 6	M/LCC 2	High loads, generator outages, fewer net imports	Load peaked at 22,942 MW during HE 18 and 19, one of the highest loads of the year. Fewer real-time net imports than the day-ahead cleared amount due to high demand in neighboring areas. Additional oil-fired generation needed in real time. Five-minute real-time Hub LMPs peaked at $483/MWh

Date	Event Type	Driver	Market and System Summary
			at 17:55.
Sep 15-17	M/LCC 2	Severe weather	Tropical cyclone Lee resulted in customer outages, which peaked at just over 100,000 customers on Sep. 16. There were a few unplanned transmission outages caused by weather, but overall system impact was small. Real-time LMPs generally in-line with day-ahead LMPs.
Oct 4	M/LCC 2	Phase II trip and unplanned generator outages	Two generators tripped during the day and were unavailable during the evening peak. Pole 1 of Phase II came off-line at 17:00 when an issue required the facility's operators to reconfigure the system. Operators manually committed several off-line fast-start units, and five-minute real-time Hub LMPs peaked at $472/MWh at 18:00 and 18:05.
Oct 23	M/LCC 2	Unplanned generator outages	M/LCC 2 declared in the late afternoon due to an imminent capacity deficiency caused by multiple unplanned generator outages totaling 835 MW. Operators anticipated tight conditions at the start of the day due to load levels and a large volume of planned outages, and made multiple supplemental commitments for capacity in the morning. Conditions tightened further following a large generator trip at 15:25. Operators manually committed one additional generator after the trip. Five-minute real-time Hub LMPs peaked at $378/MWh at 18:20 and 18:25.

3.7 Demand Response Resources

The Price-Responsive Demand (PRD) program integrates Demand Response Resources (DRRs) into the day-ahead and real-time energy markets.[206] The first subsection (3.7.1) analyzes how DRRs participate in the day-ahead and real-time energy markets, and the second subsection (3.7.2) discusses capacity market participation. The third section (3.7.3) provides an assessment of DRR compensation across all markets.

Key Takeaways

In 2023, participation in the PRD program followed trends observed in past years. DRRs primarily served as capacity and operating reserve resources available for dispatch at very high offer prices; 88% of PRD capacity was offered at $1,000/MWh in 2023. Given these high offer prices, dispatch of these resources occurred infrequently and at low quantities, with an average reduction quantity across all intervals of just 1.25 MW in the real-time energy market in 2023. DRRs mostly provided operating reserves during real-time operations; about 200 MW of 30-min reserves and just 2 MW of 10-min reserves per hour on average in 2023.

The capacity market continues to provide DRRs with the majority of overall market revenues; in 2023, DRRs received $25 million in capacity payments, which comprised 92% of total market payments to DRRs. With low dispatch levels and infrequent thirty-minute reserve pricing in 2023, DRR energy and reserve revenues totaled just $2.2 million in 2023.

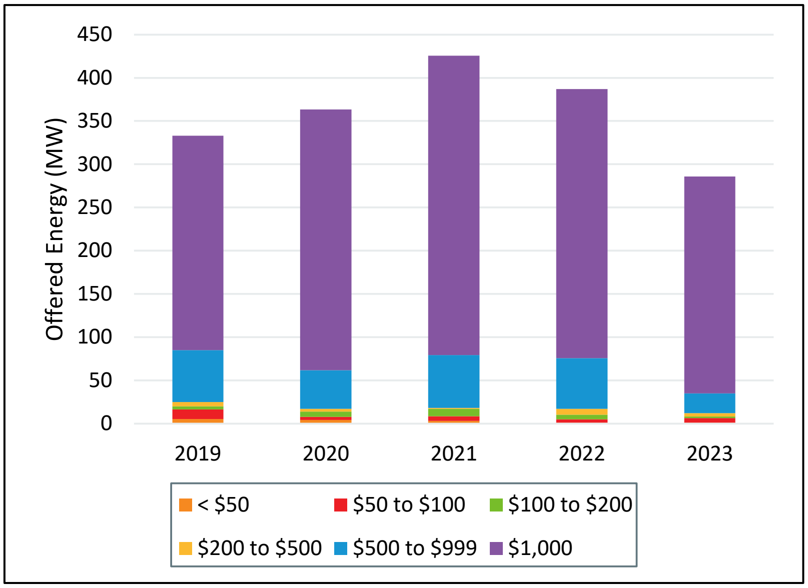
3.7.1 Energy Market Offers and Dispatch under PRD

By virtue of their high offer prices, most DRRs essentially function as reserve resources, providing energy in the real-time energy market only when prices are extremely high (~$1,000/MWh).[207] Figure 3-29 below indicates average hourly demand reduction offers in the real-time energy market, by year and by offer price category for energy offers for the past five years.

[206] This was done in order to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets). Prior to June 1, 2018, demand response resources participated in the ISO's energy markets (1) as emergency resources activated during OP-4 system conditions (i.e., a capacity deficiency) in the real-time market and (2) through the Transitional Price-Responsive Demand (TPRD) Program in the day-ahead market.

[207] Because these resources primarily function as a source of operating reserves and are dispatched at slightly higher levels (on average) in the real-time energy market, this section uses real-time offer and dispatch data to illustrate these resources' participation in the ISO's energy markets.

Figure 3-29: Demand Response Resource Offers in the Real-Time Energy Market



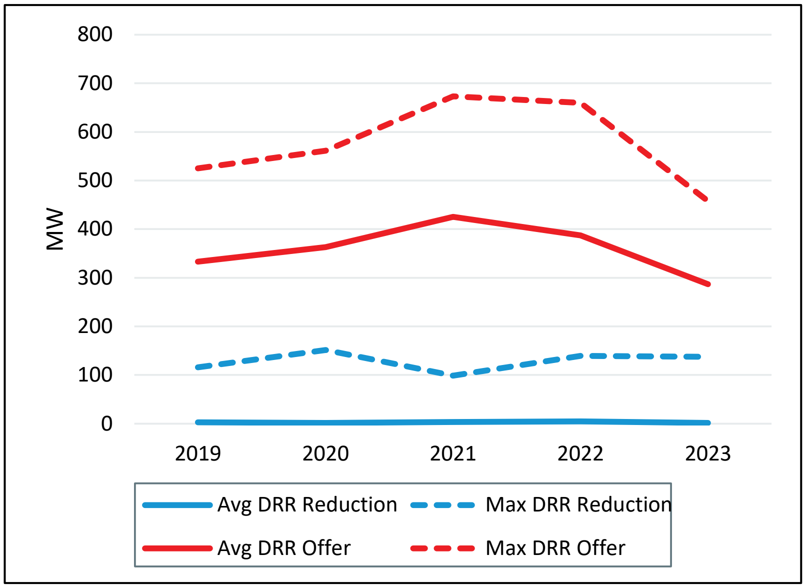
As indicated in the figure, most DRR offers continue to be priced at $1,000/MWh; 88% of offered capacity, on average, in 2023.[208] In most hours, only the lower-priced energy offers ($200/MWh or less) have a reasonable likelihood of being dispatched in the real-time energy market; these offers averaged just 3% of hourly offered DRR capacity in 2023.[209]

Given the pattern of offer prices for DRRs, the ISO dispatches relatively small quantities in the energy markets. Figure 3-30 below illustrates the reduction of DRRs in the real-time energy market relative to the resources' offered reductions over the past five years.

[208] Prior to the implementation of market rule changes associated with FERC Order 831 (Offer Caps in Energy Markets) on 3/1/2020, $1,000/MWh was the highest energy offer price that could be submitted to the ISO. That cap was eliminated with FERC Order 831, with the addition of the requirement that any offered costs greater than $1,000/MWh be supported quantitatively by the participant and verified by the ISO.

[209] Energy prices in the real-time market exceeded $200/MWh in just 1% of pricing intervals in 2023.

Figure 3-30: Demand Response Resource Reductions in the Real-Time Energy Market



The maximum reduction quantity of DRRs in the real-time energy market was 138 MW in 2023, in line with the maximum reduction quantities in prior years. However, DRRs reduced consumption far less frequently in the real-time market in 2023 – in just 13% of intervals, down from 47% of intervals in 2022. This decrease in the frequency of DRR reductions aligns with lower average energy prices observed throughout 2023. The average reduction quantity of DRRs was very small, averaging just 1.25 MW across all intervals in 2023. This reduction quantity is in line with the DRR dispatch observed in prior years, though, as noted, it occurred less frequently in 2023.

As noted earlier, DRRs also provide a source of operating reserves in the real-time energy market. DRRs are considered fast-start capable, if those capabilities have previously been demonstrated.[210] In 2023, DRRs provided only 1.9 MW, on average across all hours, of ten-minute operating reserves (similar to 2022),[211] but provided substantially more in thirty-minute operating reserves (TMOR), averaging 200 MW (down 28% from 2022).

3.7.2 Capacity Market Participation under PRD

For the Forward Capacity Market (FCM), DRRs had capacity supply obligations (CSOs) totaling approximately 436 MW in 2023, down by 104 MW (19%) compared to 2022.[212] These resources are called "Active Demand Capacity Resources" (ADCR) for capacity market purposes. All active demand resources with capacity market obligations are required to offer "physically available"

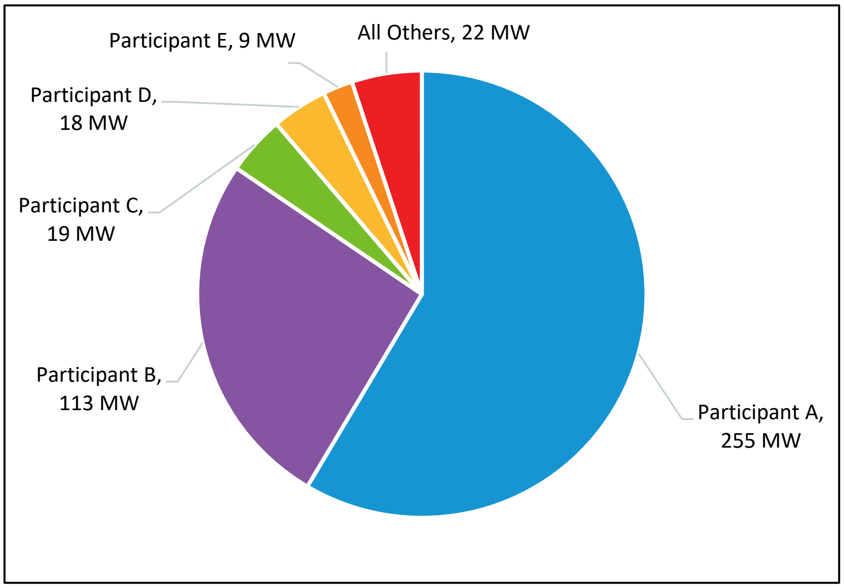
[210] To be designated during the operating day as providing thirty-minute fast-start reserves, a DRR must offer certain operating parameters consistent with fast-start operation. These operating parameters are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0 MW.

[211] While DRRs can provide ten-minute reserves, that service requires interval metering with granularity of one minute or less, to be able to provide either non-synchronized (TMNSR) or synchronized reserves (TMSR).

[212] The CSO estimate indicates the average capacity supply obligation for the calendar year.

capacity into the day-ahead and real-time energy markets.[213] Figure 3-31 indicates the CSO by participant for ADCRs.

Figure 3-31: CSO by Lead Participant for Active Demand Capacity Resources



Just nine participants had CSOs in calendar year 2023; the two largest participants accounted for approximately 85% of ADCR capacity supply obligations.

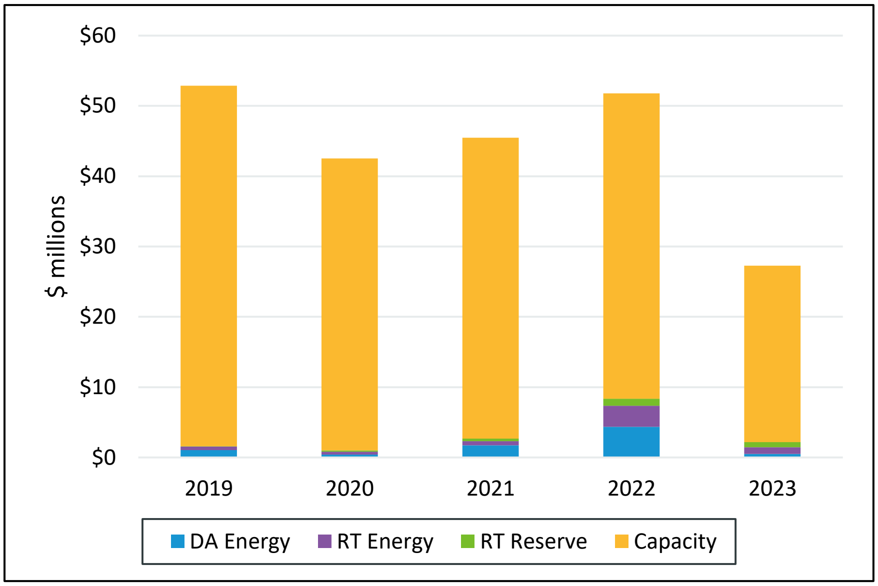
3.7.3 Wholesale Market Compensation under PRD

The capacity market continues to be the key driver of DRR compensation. DRRs have received relatively modest energy market compensation during the review period. This results from low dispatch rates in the energy market and infrequent TMOR pricing in the real-time energy market. When dispatched, DRRs are eligible to receive uplift payments. NCPC provides additional compensation to resources when energy market revenues are insufficient to cover as-offered operating costs in the day-ahead and real-time energy markets. Figure 3-32 provides a summary of capacity, energy, and reserve payments by month for the past five years.[214]

[213] The relationship between demand response resources (DRRs) and active demand capacity resources (ADCRs) is somewhat complicated. DRRs are mapped to ADCRs. More than one DRR can be mapped to an ADCR, which holds the capacity supply obligation. To satisfy the ADCR's capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR's capacity supply obligation.

[214] NCPC payments to DRRs are included within the DA and RT energy bars in this figure, and are not shown separately.

Figure 3-32: Wholesale Market Payments to Demand Response Resources



In 2023, capacity market payments to DRRs were $25 million, accounting for 92% of all DRR payments.[215] This reflects a decrease in capacity payments relative to prior years, as a result of both decreased DRR CSO and lower capacity prices. Payments for energy and reserves have remained relatively small. In 2023, total energy payments were $2.2 million, down 74% from $8.3 million in 2022. The decrease in total energy market payments to DRRs in 2023 is consistent with the lower day-ahead and real-time LMPs observed throughout 2023.[216]

[215] The FCM compensation estimate focuses just on the payments for the actual obligation on which these resources needed to deliver based upon the results of the primary FCA for the delivery period. It does not take into account any payment gains or losses that might have occurred from altering obligations through FCM bilateral and reconfiguration activities.

[216] Energy market payments to DRRs represent a very small component of overall energy market payments, which were $4.8 billion for all resources in 2023.

Section 4
External Transactions

External transactions are energy market transactions that allow market participants to transfer power between New England and its neighboring control areas, and represent an important part of the overall supply and demand picture.[217] Transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas, and provide reliability benefits to the interconnected systems.

This section reviews trends in external transactions in the day-ahead and real-time energy markets. The first section (4.1) provides an overview of external transactions across all external interfaces, while the second section (4.2) looks specifically at the performance of Coordinated Transaction Scheduling (CTS) with New York.

4.1 External Transactions

This section on outcomes, trends and drivers of import and export (external) transactions is organized in three subsections: (4.1.1) overall flows between New England and its neighboring control areas, with a breakdown across the six interfaces, (4.1.2) the pattern of fixed bidding versus price-sensitive bidding, and (4.1.3) the drivers of uplift (NCPC) payments to external transactions.

Key Takeaways

Real-time net imports averaged 1,724 MW each hour, meeting 13% of real-time load. This was the lowest level of net interchange since 2012, and down by 10% (or 190 MW) on 2022. Over 80% of total net interchange came from Canadian interfaces, a decrease from over 90% in 2022. Net imports from Canada declined by 20% (or 355 MW) from 2022 and were at the lowest levels since 2011. Lower reservoir levels in Québec led to less energy available to New England, resulting in a 20% decrease in average net interchange from Phase II, the largest interconnection with Canada.

Increased net interchange at New York North helped offset some of this decline, resulting in a 28% year-over-year increase in net interchange due to reduced congestion and relatively lower prices in New York. The reduced price premium between New York and New England in 2023 led to New England being a net importer of power over the largest interface, Roseton, 68% of the time compared to 51% in 2022.

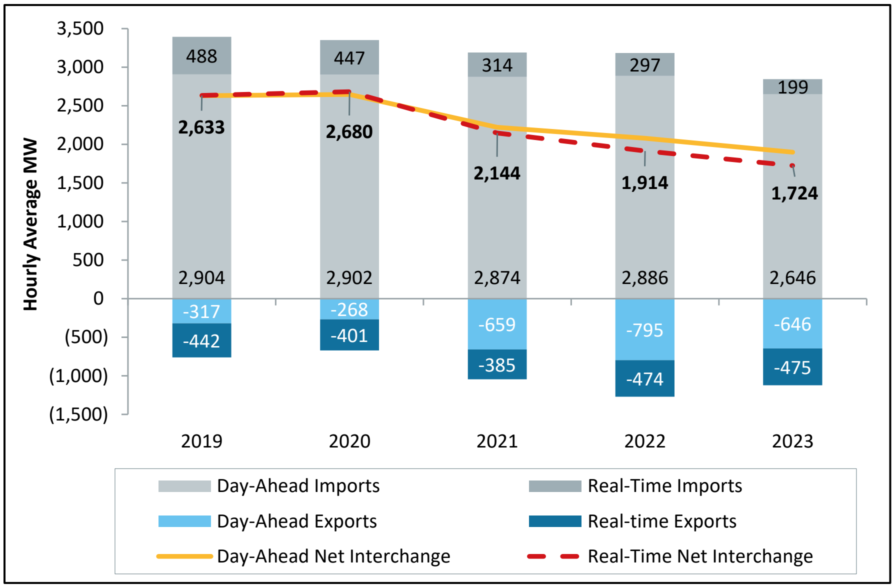
External transactions received far less uplift payments than in 2022 due to the reduction of payments to virtual transactions for relieving external congestion in the day-ahead market. In the real-time market, uplift payments increased slightly compared to 2022 due to increased forecast error at non-CTS interfaces leading to increased clearing of out-of-merit external transactions.

[217] A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

4.1.1 External Transaction Volumes

The average hourly system-wide net interchange from the day-ahead and real-time markets are shown in the line series of Figure 4-1 below. The bar series chart the hourly average imported volume (positive values) and exported volume (negative values), as well as the net interchange in both the day-ahead and real-time markets.[218]

Figure 4-1: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



Real-time net imports averaged 1,724 MW each hour, meeting 13% of real-time load. This was the lowest level of net interchange since 2012, and down by 10% (or 190 MW) on 2022. The year-over-year decline in net interchange from 2020 was mainly due to fewer import transactions over the Phase II interface. Overall, day-ahead and real-time imports fell by 240 MW and 98 MW on average, respectively.

The close proximity of the day-ahead net interchange (orange) and real-time net interchange (red) line series highlights that day-ahead market outcomes across the external nodes align well on average with real-time scheduled flows (historically within 2%).[219] However, average real-time net interchange was lower than day-ahead net interchange in 2023 by 9% (or 175 MW), which was similar to 2022 (164 MW). Additional real-time exports over the New York North interface and reductions of real-time imports at Highgate kept real-time net interchange below day-ahead cleared levels. When net real-time interchange is lower, New England must commit additional real-time native generation or import more expensive energy across other interfaces which can lead to higher real-time prices.

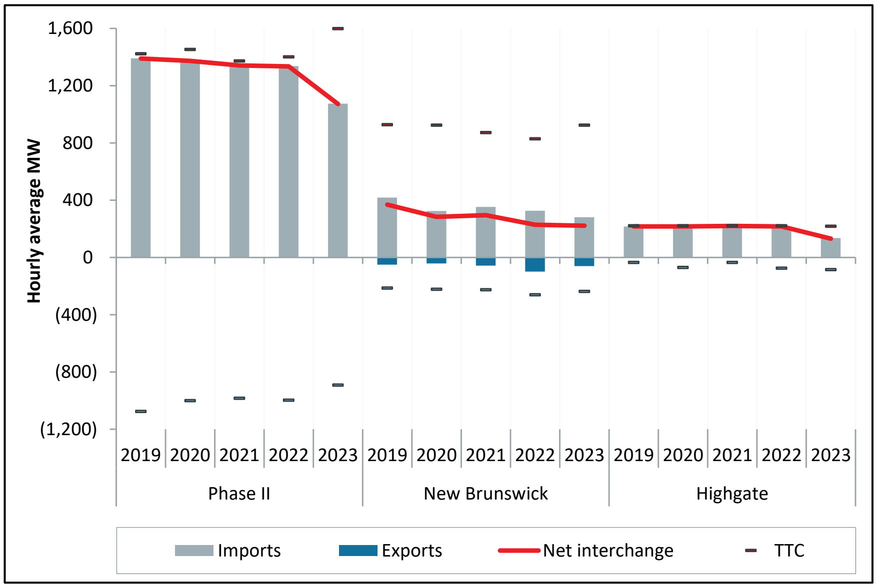
[218] The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

[219] Virtual transactions cleared at external interfaces in the day-ahead market are included in the day-ahead net interchange value. In the day-ahead energy market, virtual supply and demand are treated similarly to imports or exports.

A breakdown of flows across the Canadian Interfaces

Annual hourly average real-time net interchange volumes (red line) as well as the gross import and export volumes are shown in Figure 4-2 below, along with the real-time total transfer capability (TTC) ratings for each interface.[220]

Figure 4-2: Real-Time Net Interchange at Canadian Interfaces



New England continues to import significant volumes of power from Canada, averaging 1,426 MW per hour in 2023, or 83% of total net imports, meeting 11% of real-time load. However, net imports from Canada declined by 20% (or 355 MW) from 2022 and were at the lowest levels since 2011.

Reduced flows across *Phase II* explain the majority of the overall decrease in net interchange from Canada. In 2023, net interchange at Phase II averaged 1,072 MW per hour, a 264 MW (or 20%) decrease from 2022. Various weather factors reduced water flows in Canada, resulting in lower reservoir levels and a reduction of the excess hydroelectric generation available to import into New England.[221] Additionally, the Phase II interface took periodic unplanned outages throughout the year, including seven different trips related to smoke from forest fires in Québec. Several of these trips led to high real-time price spikes, including the capacity

[220] The total transfer capability (TTC) rating is the MW amount of power that can be reliably transferred from one system to the other over the transmission interface.

[221] For more information, see Hydro-Québec's *Quarterly Bulletin: Third Quarter* report, available https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2023-3.pdf . See for example the following commentary on page 4: "The results for 2023 are set against a backdrop of low runoff as a result of which Hydro-Québec has been reducing its exports to short-term markets. In fact, scant snow cover in late winter 2022-2023, lower-than-usual spring runoff and modest summer precipitation in northern Québec have reduced natural water inflows to the company's large reservoirs. In order to ensure optimum management of resources, the company has therefore limited its electricity sales on external markets, resulting in a significant drop in related revenues. However, this situation had no impact on Québec's energy supply or its long-term commitments with neighboring markets."

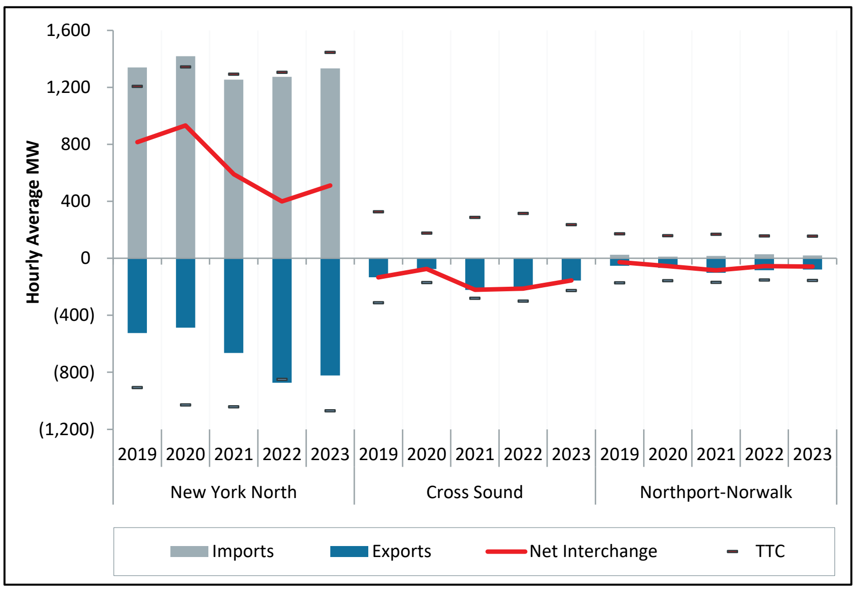
scarcity conditions on July 5, 2023. However, forest fires and other outages at the interface had little impact on annual average import levels.

At *Highgate*, net interchange was down by 85 MW per hour compared to 2022. Historically, net interchange at Highgate has averaged close to 225 MW, the maximum import TTC of the interface. In the day-ahead market, net import levels over Highgate tended to be near the full import TTC of the interface. However, real-time imports were frequently lower, which led to decreased real-time net interchange compared to prior years.

A breakdown of flows across the New York Interfaces

Real-time interchange volumes and capabilities for each of the three New York interconnections is shown in Figure 4-3 below.

Figure 4-3: Real-Time Net Interchange at New York Interfaces



On a net basis, New England imports power over the New York North interface and exports power to Long Island over both the Cross Sound Cable and Northport-Norwalk interfaces. Combining flows at all three interfaces, ISO-NE net imported an average of 298 MW per hour (or 2% of total real-time load), an increase of 165 MW year-over-year.

At *New York North,* net interchange (red line) increased year-over-year, up 28% (or 111 MW per hour) compared to 2022 but down 45% (or 422 MW) compared to the five-year high value (2020). The increase in net interchange was due to less congestion in New York as a result of completed transmission work in the New York control area. The congestion component of the New York price fell from $30.42/MWh to $8.52/MWh between 2022 and 2023, helping improve price convergence between New York and New England. During 2023, New England prices averaged $0.45/MWh less than New York prices, compared to a difference of $4.45/MWh (lower) in 2022.

New England typically exports power to Long Island over the *Cross Sound Cable* and *Northport-Norwalk* interfaces. In 2023 *net exports* at Cross Sound Cable averaged 155 MW, which was 57

MW lower than in 2022 (212 MW).[222] Exports fell at Cross Sound Cable because the interface went out-of-service in late July 2023 and remained on outage until late October 2023. At Northport-Norwalk, net exports averaged 58 MW, which was in line with prior years.

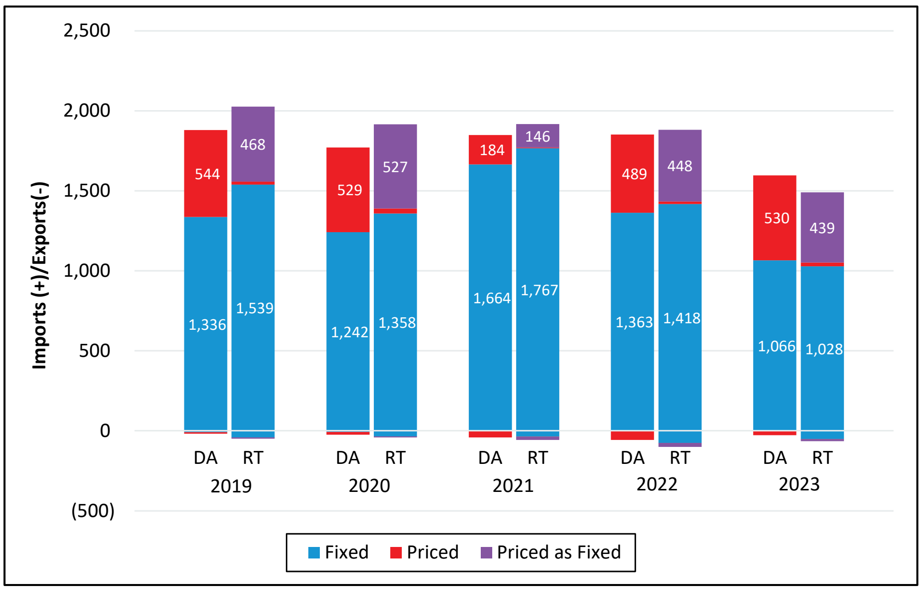
4.1.2 External Transaction Participation

In Section 3, we assessed overall market supply and demand-side participation in terms of the extent to which supply offers or demand bids are price-taking (fixed) versus price-making (priced). This can have important implications for price formation in the energy markets. In this section, we present a similar analysis focusing on external transactions, which participate on both the supply and demand sides of the market (i.e., supply offers for imports and demand bids for exports).

Canadian Interfaces

The composition of transactions that *cleared* at the Canadian interfaces in the day-ahead and real-time markets by fixed, priced and "priced-as-fixed" [223] is shown in Figure 4-4 below. Volumes are average MW per hour.

Figure 4-4: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)



Imports at the Canadian interfaces continue to be predominantly fixed but levels of fixed transactions fell compared to levels in 2022 in both the day-ahead and real-time markets. Phase II had the largest drop in day-ahead fixed imports, with fixed imports falling by an average of 134 MW per hour. Decreases in fixed imports at Highgate and New Brunswick in the day-ahead market were partially offset by increases in priced imports at those interfaces.

[222] Imports at the Cross Sound Cable have averaged less than 0.1 MW per hour since 2019.

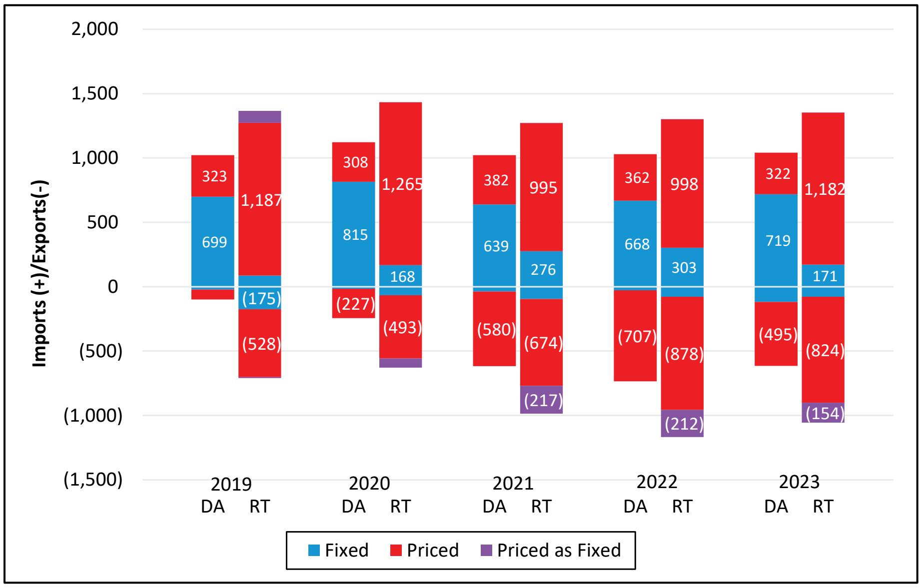
[223] A priced-as-fixed transaction is a real-time external transaction that was priced and cleared in the day-ahead market, but not reoffered in the real-time market. When day-ahead priced transactions are not reoffered in the real-time market, they are scheduled as fixed transactions.

There continues to be very low levels of price-sensitive transactions in the real-time market. At the Canadian interfaces, most priced transactions were not reoffered in real time. Without these transactions being reoffered, nearly all real-time transactions are scheduled as fixed ("Priced as Fixed" label).[224]

New York Interfaces

The composition of transactions that cleared at the New York interfaces in the day-ahead and real-time markets by fixed, priced and "priced-as-fixed" is shown in Figure 4-5 below.[225]

Figure 4-5: Transaction Types by Market and Direction at New York Interfaces (Average MW per hour)



Most day-ahead cleared import transactions at the New York interfaces were fixed (69% in 2023) while most exports were priced (81%). In 2023, we saw the first decrease in cleared day-ahead export transactions since 2020. A driver of lower exports was a reduction in congestion in New York due to the completion of major transmission projects, which led to a lower price spread between the regions in the day-ahead market, with average New England prices only $0.45/MWh lower than average New York prices in 2023 compared to $4.44/MWh lower in 2022.

A higher percentage of real-time imports (85%) are priced due to the bidding mechanics of Coordinated Transaction Scheduling (CTS) at the New York North interface. Under CTS, all real-time transactions are evaluated based on price, although participants may offer prices as low as negative $1,000/MWh, which effectively schedules the transaction as fixed. Most real-time import transactions continued to be price-insensitive at the interface. A majority of the fixed

224 In prior years, real-time import levels were higher than day-ahead levels. However, real-time imports at the Highgate interface were curtailed more frequently, which led to cleared real-time imports to be lower than in the day-ahead market.

225 Volumes not listed in the figure all averaged less than 100 MW per hour.

import transactions also occurred at New York North. The higher volume of fixed import transactions over the past three years mostly reflects the growth in wheeled transactions.[226]

4.1.3 External Transaction Uplift (NCPC) Payments

External transactions are eligible to receive uplift (or NCPC) payments when revenues are not sufficient to recover their costs. These payments often occur when external transactions clear on an ISO price forecast but are unable to recover as-offered costs through actual settled prices. External transactions (or virtual transactions placed at external nodes) can also receive uplift for relieving congestion at non-CTS external interfaces since congestion is not captured in the LMP. These payments occur when a transaction that is out-of-the-money at the system price clears in the direction counter to the constraint (e.g., an export or virtual demand bid when the interface is import-constrained) allowing a counter-party to clear in excess of the interface limit.[227] These otherwise uneconomic transactions require uplift in the absence of congestion pricing.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets are presented in Table 4-1 below.

Table 4-1: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2019	$0.02	$1.01
2020	$0.00	$1.39
2021	$1.04	$0.53
2022	$3.13	$1.17
2023	$0.08	$1.29

Typically, total uplift paid at external nodes is very small compared with other types of uplift (see Section 3.5). In the day-ahead market, these payments typically occur due to congestion; specifically when there is a surplus of infra-marginal external or virtual transactions in excess of the TTC and a virtual or priced external transaction providing "counter-flow."[228] In 2023, *day-ahead* uplift credits totaled just $0.1 million, significantly lower than the prior two years. During 2021 and 2022, high uplift payments were received by participants relieving congestion with virtual transactions at the Cross Sound Cable interface. However, high priced or fixed export transactions (or virtual demand) rarely exceeded the TTC at the interface during 2023

[226] A wheeled transaction occurs when a participant flows power from one system to another over a third party's transmission lines. For example, a participant might use these transactions to flow power from PJM through New York and into New England.

[227] For example, consider an interface with an import TTC of 100MW and an LMP of $100/MWh. If there are 200MW of imports offered at $0/MWh, only 100MW can clear (due to the TTC), unless there is a transaction to offset the remaining 100MW of excess imports. If a 100MW export is offered at $50/MWh, it can provide counter-flow. The $50/MWh exports are willing to purchase the $0/MWh imports. However, because congestion is not captured in the LMP, the energy settlement for the export will result in a loss; the exports are only willing to pay $50,/MWh and the LMP is $100/MWh. Therefore, these 100MW of exports must be paid $50/MWh to make them whole, for a total NCPC payment of $5,000. The NCPC charges are only levied to the participants importing over the interface.

[228] At non-CTS external interfaces, NCPC charges and credits are a transfer between participants creating the congestion to participants relieving the congestion.

following a change in participant behavior, which provided little opportunity for counter-flow positions to receive uplift.

Real-time uplift credits are driven by transactions scheduled out of rate due to price forecast error. In other words, transactions (at non-CTS interfaces)[229] were in-rate based on forecasted prices, but were out-of-rate based on actual prices that are used in settlements. Accurate price forecasting of LMPs helps reduce NCPC paid to external transactions. In 2023, forecast error at the non-CTS interfaces increased.

4.2 Coordinated Transaction Scheduling

This section provides an update on the assessment of how coordinated transaction scheduling (CTS) is functioning. Specifically, we review CTS performance metrics against its high-level performance indicators, including scheduling efficiency, price convergence, and price forecast error. We continue to recommend the ISO assess enhancements to price forecasting to minimize forecast error, or changes to CTS mechanics to minimize the impact of price forecast error.[230]

Key Takeaways

CTS produced similar outcomes to previous years. ISO price forecast error continues to dampen the positive impacts of CTS by producing loss-making schedules and risk for participants at the Roseton interface.

On average, the CTS engine could have used 252 MW of unutilized capacity to converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). The CTS engine did not converge prices efficiently due to the unwillingness of participants to adjust to real-time price differences, which in turn is likely influenced by the risks they bear due to price-forecast error.

We encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy. Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost.

4.2.1 CTS Performance

We assess CTS performance against two measures of efficiency: the flow of power from the lower-to higher-cost region and degree of price convergence between New England and New York.

[229] At the CTS interface, out-of-rate transactions are not entitled to NCPC, but also do not incur NCPC charges.

[230] A summary of this and other recommendations can be found in the executive summary of this report. For a more in-depth analysis of CTS outcomes, see our *2022 Annual Markets Report* (June 5, 2023) available at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf

A summary of CTS power flows between the two control areas is shown in Table 4-2 below. The percentage of time power flowed into New England is shown in the *Net Flow* column.[231] The percentage of time the flow was directionally correct (i.e., power flowed from lower- to high-cost region, based on actual prices) is shown in the *Correct Flow* column.[232] The average New England price premium is shown for context, as a primary driver of flow direction.

Table 4-2: Summary of CTS Flows

Year	Net Flow (% of intervals) to ISO-NE	Correct Flow (% of intervals)	Average New England Price Premium ($/MWh, without CTS Congestion)	Average New England Price Premium ($/MWh, with CTS Congestion)
2019	91%	58%	$3.19	($0.72)
2020	95%	55%	$1.99	($0.67)
2021	69%	56%	$1.96	($1.65)
2022	51%	57%	($3.06)	($4.23)
2023	68%	55%	$1.90	($1.05)

In 2023, power flowed into New England from New York 68% of the time. The increase from 2022 reflects both imports and exports responding to the average real-time New England price premium of $1.90/MWh in 2023, compared with a $3.06/MWh New York price premium in 2022.[233] Despite the alignment of net flow and the average price premium, CTS scheduled flows in the correct direction only 55% of the time on a 15-minute basis (i.e., from lower- to higher-cost region)—similar to the prior four years.

Table 4-3, below, shows a summary of price convergence between New York and New England and CTS price forecast error.

Table 4-3: Summary of Price Convergence and Forecast Error

Year	NY LBMP	NE LMP	Average Absolute Price Spread	Average Absolute Price Spread as % of ISO-NE LMP	Average Absolute Price Spread Forecast Error	Average Absolute Price Spread Forecast Error as % of ISO-NE LMP
2019	$26.47	$29.66	$9.70	33%	$7.96	27%
2020	$20.46	$22.45	$6.87	31%	$6.34	28%
2021	$41.07	$43.03	$12.76	30%	$10.78	25%
2022	$85.94	$82.88	$24.64	30%	$23.45	28%
2023	$32.77	$34.67	$12.12	35%	$10.10	29%

[231] Fixed wheeling transactions at the New York North (NYN) interface are ignored in all of the analyses contained in this section. These transactions are not cleared in the CTS process. On average, in 2023 there were 255 MW of fixed-wheeling transactions net importing over the NYN interface in each interval.

[232] The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface. The NYISO pricing node is "N.E._GEN_SANDY PD" (Sandy Pond) and the ISO-NE node is ".I.ROSETON 345 1" (Roseton). Congestion pricing is removed from external prices to ensure we are better-capturing the marginal cost of energy in each control area at the border. When the ramp or flow limit binds, the prices at the interface reflect the bids and offers that set price based on the forecast, and not necessarily the marginal cost of energy in each control area.

[233] These prices do not reflect CTS congestion to better capture the marginal cost of energy in each control area, rather than the prices of the CTS transactions that set price when an interface constraint is binding.

Although the absolute price spread in 2023 ($12.12/MWh) was less than half of in 2022, the absolute price difference between New York and New England was 35% of the LMP, similar to previous years.

Many variables impact the price spread between New York and New England (e.g., generator and transmission outages, interconnections with other areas, differences in scarcity pricing rules) so the price spread cannot be fully attributed to the efficiency of CTS solutions. However, CTS solutions did not efficiently utilize the New York North interface capacity to converge prices. On average, the CTS engine could have used 252 MW of unutilized capacity to converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). The CTS engine did not converge prices efficiently due to the unwillingness of participants to adjust to real-time price differences, which in turn is likely influenced by the risks they bear due to price-forecast error.

In 2023, 57% of cleared CTS transactions were offered at less than -$50/MWh. These price-insensitive CTS transactions were typically not exposed to real-time prices—88% of offered CTS transactions priced at less than -$50/MWh were backed by a day-ahead transaction. This strategy is likely a product of price-forecast error risk borne by CTS participants. The average absolute price spread forecast error was $10.10/MWh (29% of the New England LMP) in 2023.

Section 5
Virtual Transactions

In this section, we present our assessment of virtual transaction participation in the day-ahead energy market, including the level of activity, or competition added to the day-ahead energy market. We cover the trends and drivers of participation and the value added to market efficiency. Finally, we present and discuss the results of profitability metrics at both a system and location level.

Key Takeaways

The volume of cleared virtual transactions increased in 2023; cleared virtual supply and demand were up by 25% and 29%, respectively (by 161 MW and 120 MW per hour, resp.)

Average cleared virtual supply (810 MW per hour) increased mainly at the load zones due to growing energy output from settlement-only generators (SOGs). Virtual supply in 2023 was notably higher during the daytime hours than other times of the day, reaching as high as 1,473 MW per hour. We have observed a clear relationship between virtual supply and photovoltaic generation, particularly on high solar output days. Most photovoltaic generation in the ISO-NE market registers as settlement-only generators (SOG). Since SOGs cannot clear in the day-ahead market, virtual participants anticipate the additional real-time generation and clear virtual supply in the day-ahead market in their place. These virtual supply offers effectively replace the price-taking SOGs that show up in real time, and helped improve price convergence during the middle of the day.

This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and don't pose an inefficient participation obstacle.

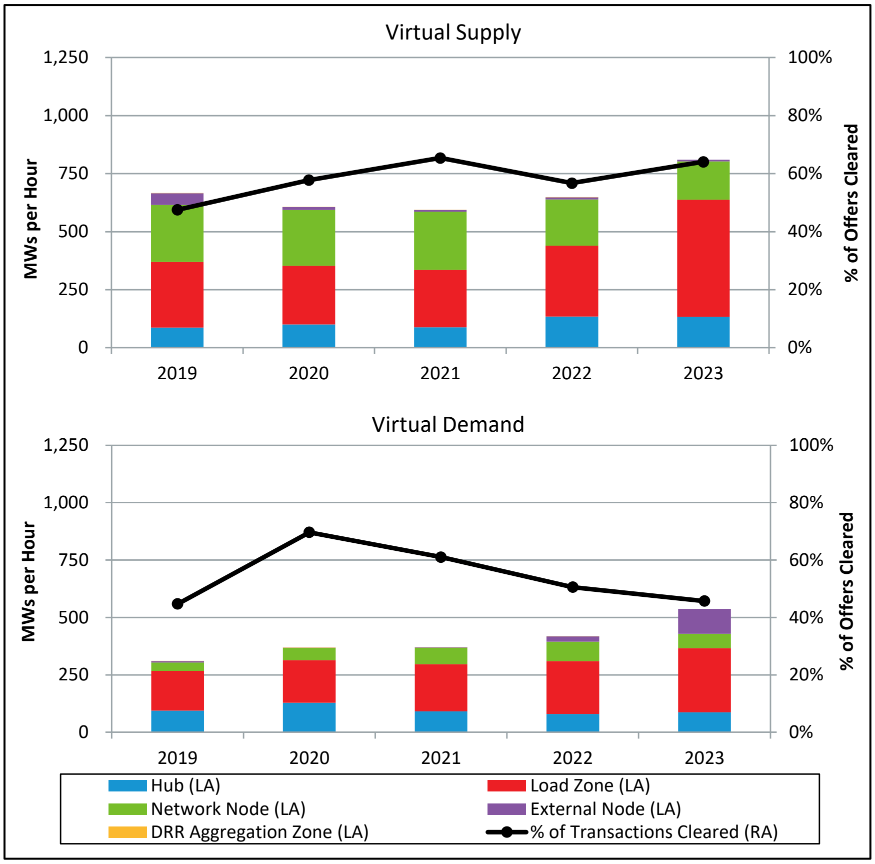
NCPC charges for virtual transactions decreased in 2023, averaging $0.74/MWh. After accounting for NCPC charges, virtual supply transactions remained profitable ($0.53/MWh) while virtual demand transactions incurred the largest losses over the five-year period (-$2.83/MWh).

Virtual Transaction Volume

Participants submit virtual demand bids and virtual supply offers to profit from, or limit exposure to, differences in the day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model to better reflect real-time conditions. The average volumes of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 5-1 below.[234]

[234] Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

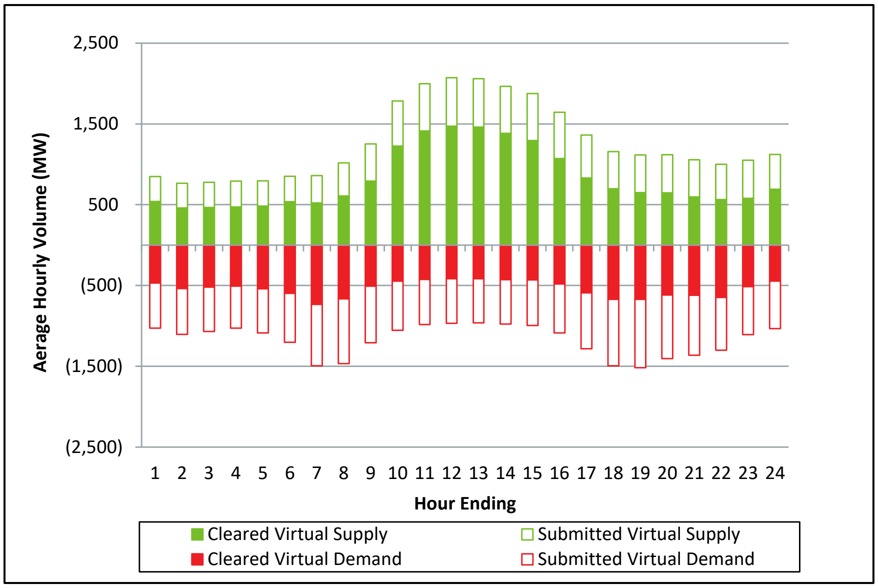
Figure 5-1: Cleared Virtual Transaction Volumes by Location Type and Bid Type



Cleared virtual transactions averaged 1,348 MW per hour in 2023, up 26% on 2022. Both cleared virtual supply and cleared virtual demand increased; virtual supply by 25% and virtual demand by 29%. Average cleared virtual supply (810 MW per hour) increased mainly at the load zones due to growing energy output from settlement-only generators (SOGs). Average cleared virtual demand (538 MW per hour) increased at external nodes due to increased clearing at the Highgate interface.

In 2023, higher levels of virtual supply tended to be submitted and cleared during the middle part of the day, while higher levels of demand tended to be submitted and cleared during the morning and evening ramp periods. This can be seen in Figure 5-2, which shows the average hourly volume of submitted and cleared virtual transactions by time of day in 2023. Virtual supply is depicted as positive values, while virtual demand is depicted as negative values.

Figure 5-2: Average Hourly Submitted and Cleared Virtual Transaction Volumes by Time of Day, 2023



The average volumes of cleared virtual supply in 2023 were higher during the daytime hours than other times of the day. Between hours ending 9 through 17, cleared virtual supply averaged about 1,215 MW per hour compared to 567 MW per hour during the rest of the day. We have observed a clear relationship between virtual supply and photovoltaic generation, particularly on high solar output days. Most photovoltaic generation in the ISO-NE market registers as SOGs.[235] Since SOGs cannot clear in the day-ahead market, virtual participants anticipate the additional real-time generation and clear virtual supply in the day-ahead market in their place.[236] These virtual supply offers effectively replace the price-taking SOGs that show up in real time.

Meanwhile, the average volume of cleared virtual demand continues to be slightly higher during the morning and evening ramping periods, when loads are higher and prices tend to be more volatile in the real-time market.

Virtual Transaction Profitability

Virtual transactions profit from differences between day-ahead and real-time prices. However, transaction costs in the form of NCPC charges can turn otherwise profitable virtual transactions into unprofitable transactions on a net basis.[237] This limits the ability of virtual transactions to

[235] By the end of 2023, settlement-only photovoltaic generators had an installed capacity of about 2,160 MWs.

[236] The differences in the supply mix between the day-ahead and real-time energy markets are examined in Section 3.2.4.

[237] The ISO allocates the following NCPC charges to cleared virtual transactions: (1) **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) incur a charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations; and (2) **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because the total day-ahead economic NCPC is divided among a much larger quantity of energy.

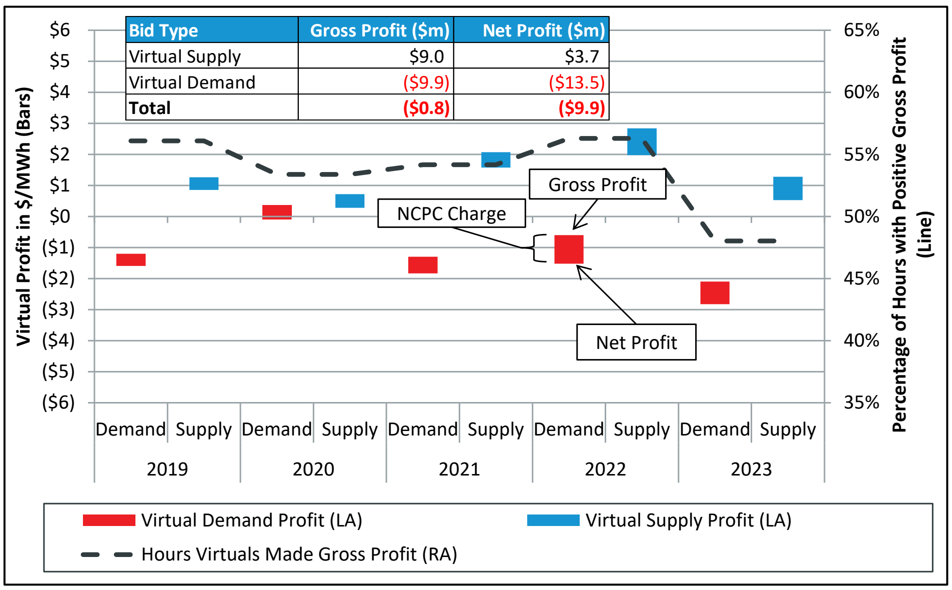
Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report.

converge prices between day-ahead and real-time prices, which is one of their intended market functions.[238]

This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation.[239]

Figure 5-3 illustrates the profitability of virtual transactions along with the impact of NCPC charges on profitability. This figure displays the average annual gross and net profit of virtual transactions since 2019 (left axis).[240]

Figure 5-3: Average Annual Gross and Net Profits for Virtual Transactions



Virtual supply made a gross profit of $1.28/MWh in 2023. While virtual supply profitability decreased substantially from 2022 ($2.84/MWh), profitability was more in line with prior years. Despite the decrease from 2022, virtual supply continued to make higher profits during the middle of the operating day, when day-ahead prices were typically higher than real-time prices. Between hours ending (HE) 9 and 17, participants made a total net profit of over $2.9 million in 2023, which accounted for 80% of the virtual supply's net profit ($3.7 million) during the year.

[238] The role of virtual transactions in price convergence is discussed in more detail in Section 3.1.3.

[239] For more information on recommended market design changes, see the table in the Executive Summary.

[240] The bars are categorized by year and bid type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MWh NCPC charge. The inset table shows profitability by bid type for 2023. Additionally, the dashed black line shows the percentage of hours each year in which virtual transactions were profitable on a gross basis (right axis). The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

The relationship between virtual supply and settlement-only photovoltaic generation helped drive these higher profits during the middle of the day. Participants cleared more virtual supply in 2023 during HE 9 to 17, averaging 1,215 MW an hour compared to 898 MW per hour in 2022. However, this increase in cleared virtual supply outpaced the growth in photovoltaic settlement-only generation, which only increased by 55 MW per hour from HE 9 to HE 17. The growth in virtual supply compared to photovoltaic SOGs helped improve price convergence during the middle of the day, which lowered profitability for virtual supply.

Virtual demand, incurred a gross loss of -$2.09/MWh on average in 2023, the highest gross loss for virtual demand over the last five years. Virtual demand has typically lost money on an annual basis as real-time prices tend to be lower than day-ahead prices, on average. Additionally, participants cleared increased virtual demand at external nodes in 2023. These bids tend to be related to financial hedges for import transactions rather than speculative bids aiming to profit on day-ahead and real-time price differences.[241]

Average NCPC charges for virtual transactions decreased compared to 2022 (from $0.88/MWh to $0.74/MWh). NCPC charges decreased as total NCPC charges decreased for the system.[242] In 2023, virtual supply remained profitable after the netting of NCPC charges, making a net profit of $0.53/MWh, on average. Virtual demand lost $2.83/MWh, on average, after accounting for NCPC charges.

Most Profitable Locations for Virtual Supply

Details of the top 10 most profitable locations for virtual supply in 2023, after accounting for transaction costs and NCPC charges/credits (ranked by total net profit), are shown in Table 5-1 below.

Table 5-1: Top 10 Most Profitable Locations for Virtual Supply, 2023

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.H.INTERNAL_HUB	Hub	1,616,159	1,173,561	$1,566	**$677**	$1.33	$0.58	32
UN.BINGHAM 34.5BNGW	Gen Node	181,933	97,529	$668	**$595**	$6.85	$6.10	15
.Z.MAINE	Load Zone	777,722	531,297	$1,014	**$584**	$1.91	$1.10	18
.Z.SEMASS	Load Zone	952,411	719,701	$1,002	**$449**	$1.39	$0.62	18
.Z.VERMONT	Load Zone	618,214	428,535	$728	**$416**	$1.70	$0.97	15
.Z.CONNECTICUT	Load Zone	410,234	272,066	$416	**$231**	$1.53	$0.85	17
.Z.WCMASS	Load Zone	342,221	274,899	$399	**$193**	$1.45	$0.70	13
UN.BULL_HL 34.5BLHW	Gen Node	199,197	108,117	$265	**$186**	$2.45	$1.72	15
.Z.RHODEISLAND	Load Zone	403,670	317,192	$388	**$135**	$1.22	$0.43	13
UN.OAKFIELD34.5OAKW	Gen Node	112,878	61,309	$167	**$117**	$2.72	$1.91	11

[241] For example, a participant with a large portfolio of generation assets may use virtual demand to hedge against higher real-time prices that might occur if one of their assets goes out of service in the real-time market after clearing in the day-ahead market.

[242] For more information on why NCPC decreased in 2023, see Section 3.5.

Seven of the top ten locations consisted of the Hub and six of the eight load zones. High total net profits at these locations were in line with the lower real-time prices at these locations, especially during the middle of the operating day.

The other three locations are associated with wind power generation. Certain wind generators are part of the set of resources known as do-not-exceed (DNE) dispatchable generators (DDGs). Wind generators often clear lower volumes in the day-ahead market, but produce more real-time output at low or even negative real-time prices. Virtual supply participants fill this gap by clearing virtual supply at prices more in line with real-time expectations, particularly on windy days.[243]

Most Profitable Locations for Virtual Demand

Details for the 10 most profitable locations for virtual demand in 2023, after accounting for transaction charges and all relevant NCPC charges/credits (ranked by total net profit), are shown in Table 5-2 below.[244]

Table 5-2: Top 10 Most Profitable Locations for Virtual Demand, 2023

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.MYSTIC 18.1MYS9	Gen Node	1,762	1,266	$11	**$10**	$8.76	$7.71	3
LD.HARRIS 13.2	Load Node	1,544	1,293	$7	**$6**	$5.19	$4.64	1
LD.MIDLE_RV13.8	Load Node	347	347	$6	**$5**	$17.43	$14.55	1
UN.MIDDLETN115 MI10	Gen Node	4,850	2,857	$7	**$5**	$2.50	$1.65	2
UN.OAKFIELD34.5OAKW	Gen Node	74,917	829	$4	**$4**	$5.19	$4.68	3
LD.PAXTON 115	Load Node	1,919	1,179	$5	**$4**	$4.47	$3.24	2
UN.PUTNAMRD34.5DFLW	Gen Node	128	128	$4	**$4**	$30.42	$28.58	1
LD.LITCHFLD13.8	Load Node	269	269	$4	**$3**	$15.42	$12.48	1
LD.DEER_ISL115	Load Node	188	188	$4	**$3**	$20.07	$17.69	1
UN.OCEAN_ST13.8OSP1	Gen Node	820	693	$4	**$3**	$6.25	$4.60	2

The 10 most profitable locations consisted of generator and load nodes that saw little virtual demand trading activity throughout the year. No single location saw net profits above $10 thousand over the course of the year, and these ten locations made a cumulative net profit of under $50 thousand during 2023. Collectively, these ten locations cleared an average of about 1 MW per hour for all of 2023.

[243] These locations tend to be riskier as well, given the difficulty of forecasting wind generation. For example, if a participant expects high wind output in the real-time market, they might clear virtual supply in the day-ahead market at a low price, and expect to profit off negative real-time prices. However, if the wind generation does not meet day-ahead expectations, these locations will likely be unconstrained, and the participant would have to pay its day-ahead obligation back at a higher real-time price.

[244] For more information about the additional charges for virtual transactions, see *Section IV.A Recovery of ISO Administrative Expenses*, Schedule 2 Energy Administration Service, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf

Section 6
Forward Capacity Market

Below, we review key trends and performance of New England's Forward Capacity Market (FCM). The auction continues to clear with a surplus of capacity at a payment rate well below the estimated cost of new entry. The surplus conditions can be attributed to a relatively unchanged installed capacity requirement, low amounts of retirements and steady additions of new generation, notably from renewable or policy-sponsored projects (wind, solar, and battery storage). New additions in New England have transitioned away from gas-fired generation and demand response and toward mostly renewable projects that will come online over the next three years.

There have been few capacity scarcity condition (CSCs) since the Pay for Performance (PfP) settlement rules were implemented in June 2018. A short duration CSC (30 minutes) was triggered in July 2023 by the unplanned outage of the Phase II interconnection; just the third CSC in six years. The frequency of CSC events has been well below ISO published forecasts due to limited periods of stressed system conditions. Therefore, performance deviations settled through the PfP two-settlement construct have been negligible compared to base capacity payments.

6.1 Review of Eighteenth Forward Capacity Auction (FCA)

This section provides a closer review of FCA 18, the most recent primary auction held in February 2024.[245]

Key Takeaways

Qualified capacity participating in FCA 18 exceeded the Net Installed Capacity Requirement (NICR) by over 6 GW or 20% (36,560 MW qualified compared to 30,550 MW). Cleared capacity totaled 31,556 MW, leaving a surplus of about 1 GW at the auction-clearing price of $3.58/kW-month.

The Net CONE value for FCA 18 was $9.08/kW-month, up 23% from FCA 17, and was the most significant change to the auction input parameters that resulted in a shift of the demand curve to the right. This increase reflected the impact of inflationary indices applied to key inputs into Net CONE. Net ICR increased slightly (1%) due to higher future load forecasts and an increase in expected forced outages for import capacity resources.

Over 1,140 MW of new resources cleared, with battery storage projects (740 MW) and wind projects (185 MW) representing the largest new entrant types. Oil generation and import resources made up the largest share of uncleared capacity FCA 18. Of the 2,400 MW of existing capacity exiting the auction, over 800 MW retired permanently while the remaining de-listed for one year.

Based on our pre-auction review of de-list bids, excess capacity before and during the auction,

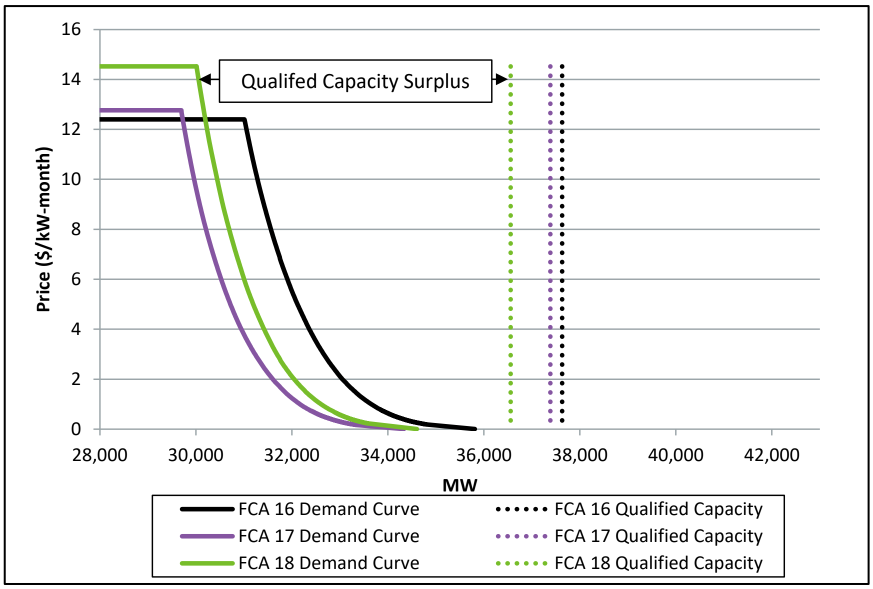
[245] Further detail on the auction is contained in the IMM's *Winter 2023 Quarterly Markets Report*, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

and the liquidity of dynamic de-list bids, it is our opinion that auction outcomes were the result of a competitive process.

6.1.1 Auction Inputs

The sloped system and zonal demand curves are based on a Marginal Reliability Impact (MRI) methodology, which estimates how an incremental change in contracted capacity affects system reliability at various capacity levels.[246] The demand curves and qualified capacity for the past three auctions (FCAs 16, 17, and 18) are shown in Figure 6-1 below.

Figure 6-1: Net ICR and System Demand Curves



The Net Installed Capacity Requirement (Net ICR) and Net Cost of New Entry (Net CONE) are used as the scaling points for the MRI curve. The Net CONE value for FCA 18 was $9.08/kW-month, up 23% from FCA 17, and was the most significant change to the auction input parameters that resulted in a shift of the demand curve to the right. This increase reflected the impact of inflationary indices applied to key inputs into Net CONE.[247]

The Net ICR value for FCA 18 was 30,550 MW, slightly higher than the 30,305 MW Net ICR in FCA 17. The increase was driven by higher future load forecasts and an increase in expected

[246] The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE". For more information on why the ISO implemented a sloped demand curve, see our *2019 Annual Markets Report* (June 9, 2020), Section 6.1, available at https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf

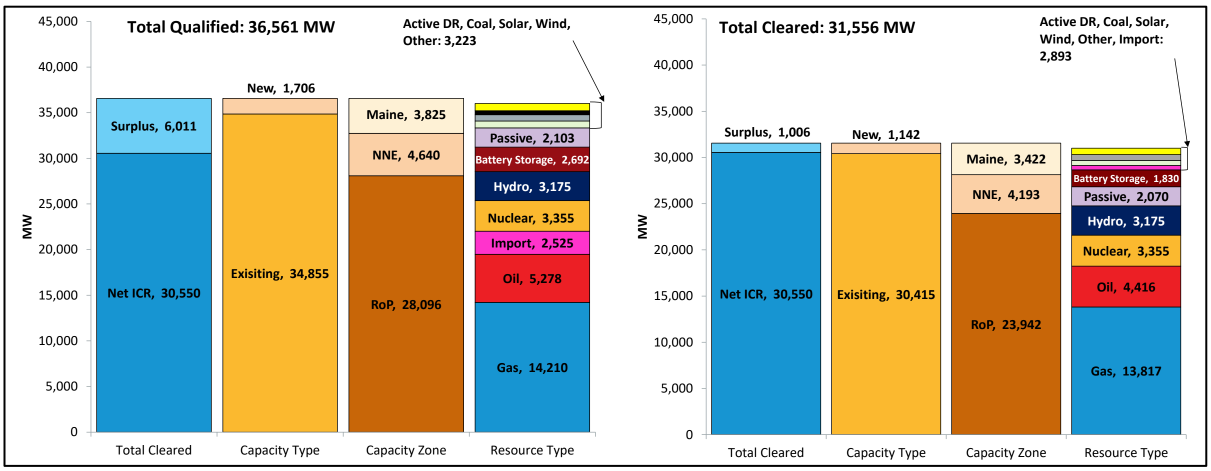
[247] Net CONE reflects the breakeven capacity payment needed to cover the costs of a combustion turbine, which was selected as the most economically viable resource in the FCA 16 Net CONE study. The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). See *Updates to CONE, Net CONE, and Capacity Performance Payment Rate* (December 31, 2020), available at https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

forced outages for import capacity resources.[248] In FCA 18, qualified capacity saw a decrease of only 825 MW compared to FCA 17, primarily due to a reduction in existing qualified capacity.

6.1.2 Qualified and Cleared Capacity

The qualified and cleared capacity in FCA 18 compared to Net ICR (blue bars) is illustrated in Figure 6-2 below. Total qualified and cleared capacity are broken down across three dimensions: capacity type, capacity zone and resource type.

Figure 6-2: Qualified and Cleared Capacity in FCA 18



Over 1,700 MW of new capacity qualified for FCA 18, with new battery storage projects comprising the largest proportion at 1,167 MW. The renewable technology resource (RTR) exemption was active for its last auction, exempting 389 MW of new sponsored policy resource capacity from the Minimum Offer Price Rule (MOPR).[249]

While 6 GW of surplus qualified capacity entered FCA 18, only 1 GW of surplus cleared at the end of the auction. The uncleared capacity comprised of existing resources that de-listed (4.44 GW) and new supply resources (0.56 GW) that exited the market at prices greater than the associated zonal clearing price. Oil generation and import resources made up the largest share of uncleared capacity in FCA 18, while battery storage and wind generation had modest increases in cleared capacity.

The ISO modelled two capacity zones in addition to Rest-of-Pool: the export-constrained zone of Northern New England (NNE), and the nested export-constrained zone of Maine. The qualified and cleared values by capacity zone are illustrated in the second orange bars. There was no price separation between capacity zones in the auction.

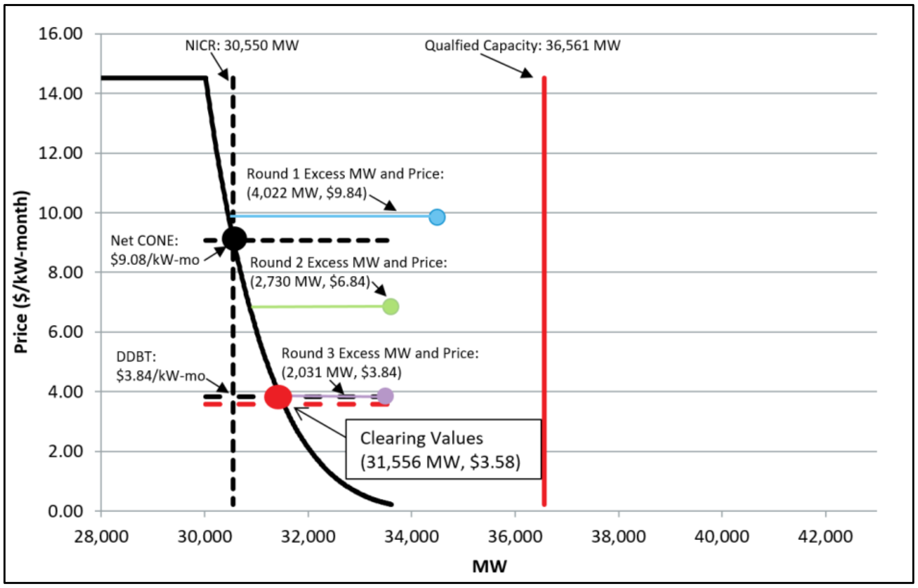
[248] See Proposed Installed Capacity Requirement (ICR) and Related Values For Forward Capacity Auction (FCA) 18 (associated with the 2027-2028 Capacity Commitment Period) (August 23,2023) by Helve Saarela and Manasa Kotha, available at https://www.iso-ne.com/static-assets/documents/2023/08/a03_2023_08_23_pspc_proposed_icr_related_values_for_fca18_final.pdf

[249] More information on the RTR exemption for FCA 18 can be found in the FERC Filing accepting tariff revisions centered on the removal of the minimum offer price rule (MOPR). See *Order Accepting Tariff Revisions Docket No. ER22-1528-000* (May 27, 2022), available at https://www.iso-ne.com/static-assets/documents/2022/05/er22-1528-000_5-27-2022_order_accept_mopr_removal.pdf

6.1.3 Auction Results and Competitiveness

The demand and supply side parameters for FCA 18 are summarized in Figure 6-3 below. All ISO-defined parameters are black dashed lines (Net CONE, Net ICR, and DDBT) and qualified and cleared values are shaded red (clearing price/quantity and qualified capacity). The blue, green and purple markers represent the end-of-round prices and excess supply.

Figure 6-3: System-wide FCA 18 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces at $3.58/kW-month. The fourth round opened with 2,031 MW of excess capacity above demand (purple dot) and a starting price equal to the Dynamic Delist Bid Threshold (DDBT), allowing existing resources to exit the market through dynamic de-list bids.

A rationable dynamic de-list bid set the final clearing price of $3.58/kW-month for all capacity zones and interfaces. A dynamic de-list bid priced at $3.579/kW-month would have led to system-wide supply to fall short of system-wide demand if cleared.[250]

The Substitution Auction (CASPR)

In FCA 18, the substitution auction did not proceed, as there were no active demand bids. The nine retiring resources that qualified for the substitution auction did not receive CSOs in the primary auction, a prerequisite for submitting a demand bid in the substitution auction.

[250] Due to minimum rationing limits, the necessary CSO to meet system-wide demand could not be allocated evenly among all resources attempting to exit the auction. Instead, the market clearing engine rationed one resource's de-list bid to retain the necessary amount of CSO for system-wide supply to meet system-wide demand.

FCA 18 Competitiveness Assessment

The IMM conducts a pivotal supplier test prior to the auction based on portfolios with existing capacity relative to the system and local requirements (see Section 2.4.1).[251] However, capacity conditions change as the auction proceeds (new resources leave, existing capacity de-lists, the demanded quantity changes) and a supplier that was not pivotal at the start of the auction (when the IMM made the pivotal status determination) may become pivotal during the auction as the surplus falls.[252]

There were no pivotal suppliers at the start of the auction, but as the auction entered its fourth (and final) round with excess capacity of approximately 2 GW, there were six pivotal suppliers with a portfolio above the system-wide excess capacity. However, the low volume of pivotal supplier de-list bids combined with the bid prices occurring below the DDBT indicated that the exercise of supplier-side market power was not a concern. We did not observe bidding behavior that would be consistent with the exercise of market power. Based on our pre-auction review of de-list bids, excess capacity before and during the auction, and the liquidity of dynamic de-list bids, it is our opinion that auction outcomes were the result of a competitive process.

6.2 Forward Capacity Market Outcomes

This section provides a review of overall trends in prices and volumes in the FCM including the FCM credits and charges, changes to the resource mix, and trading activity in secondary markets for capacity.

[251] The initial pivotal supplier calculation is limited to pre-auction calculations and applies only the mitigation of static de-list bids.

[252] In fact, suppliers that have been deemed pivotal prior to the auction may not be pivotal at the start of the auction (if the quantity demanded along the sloped demand curve is greater than Net ICR or Local Sourcing Requirement in import-constrained capacity zones).

Key Takeaways

Capacity prices have cleared significantly lower than the Net CONE benchmark, reflecting surplus conditions above NICR and no significant gas-fired generation entry. Projected payments associated with FCA 18 outcomes are expected to be $1.3 billion, a 37% increase from the record-low payments associated with FCA 17.

Just the third Pay-for-Performance event occurred in 2023 since the rules were implemented in 2018. The July event lasted 6 five-minute intervals (30 minutes) and resulted in the transfer of $10.9 million from under-performing resources to over-performing resources. The number of events continue to be significantly fewer than predicted by ISO forecasting models, and therefore performance charges continue to represent a very small proportion of base capacity payments.

New entrants to New England have largely consisted of wind, solar, and battery storage, which made 67% of all new generator additions since FCA 15. Capacity backed by imports has continued to clear at a low level in FCA 18 (and 17) relative to historical levels, an indication of potentially high capacity values in neighboring jurisdictions. Major retirements have comprised of nuclear, oil, and gas resources; notably the Mystic combined cycles (~1,400 MW) will retire in May 2024, and nearly 900 MW of gas- and oil-fired generation retired in FCA 18.

Retirement timings do not always align with capacity commitment periods and remain outside of the publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants, and we therefore recommend that ISO publish such retirements to the marketplace.

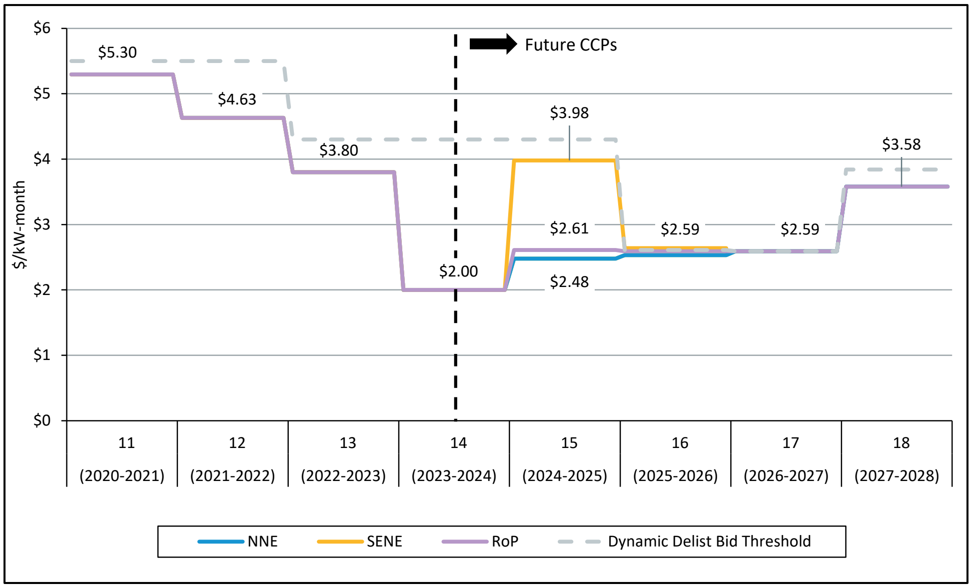
6.2.1 Trends in Capacity Prices and Payments

Capacity prices have cleared significantly lower than the Net CONE benchmark, reflecting surplus conditions above NICR and no significant gas-fired generation entry. For the recent auction, this translates to total payments of about $1 billion, significantly less than the peak prices and payments in FCA 9 for the period 2019/2020 ($9.55/kW-mo, $4.3 billion).

Rest-of-Pool and Zonal FCA Clearing Prices

The changes in capacity clearing prices for each FCA are illustrated in Figure 6-4 below. The different colored lines represent the clearing price paid to resources in each modeled capacity zone.

Figure 6-4: Forward Capacity Auction Clearing Prices



Capacity prices have steadily declined following the high prices prior to *FCA 11* (not shown), to which the market responded with new entry.[253] The decrease in prices through FCA 14 was primarily driven by entry from new sponsored policy resources, while relatively few existing resources retired. There has been no notable location price separation, with the exception of *FCA 15,* reflecting a generally unconstrained system. Significant decreases in capacity in the Southeastern New England (SENE) capacity zone, primarily the retirement of Mystic 8 and 9, meant that the zone cleared at a higher price than the RoP price.

Until *FCA 18,* there were no significant changes affected clearing prices. The auction closed at a clearing price of $3.58/kW-month, a 38% jump from the previous FCA. While the expected quantity of capacity demanded increased slightly (250 MW increase in Net ICR), the value of capacity determined through the administrative demand curve increased significantly due to inflationary increases to the Net Cost of New Entry (Net CONE). The Net CONE for FCA 18 jumped 19% year-over-year and put upward pressure on clearing prices due to its effect on the demand curve.

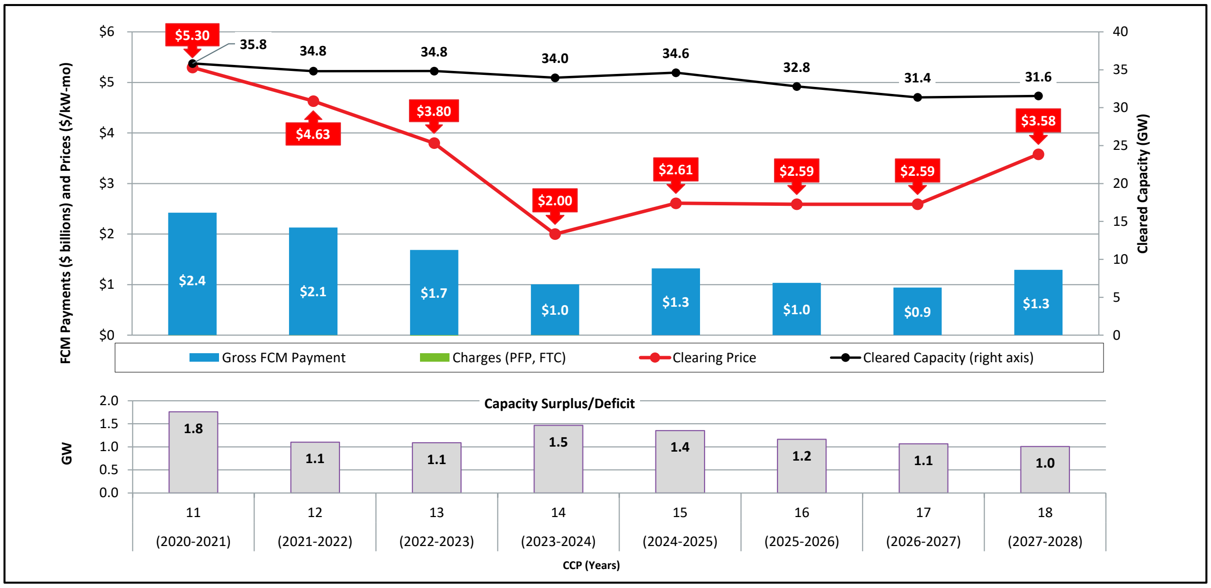
Payments by Capacity Commitment Period

FCM payments are primarily a function of clearing prices and capacity (volume) in each FCA. Total payments for capacity commitment periods (CCPs) 11-18 are shown in Figure 6-5 below, along with the key determinants: Rest-of-Pool clearing prices and cleared capacity.[254] The gray boxes in the bottom graph represent the amount of surplus capacity above the Net ICR that cleared in each FCA.

[253] Clearing prices for FCA 9 and 10 were and $9.55/kW-month and $7.03/kW-month, respectively.

[254] The blue bars represent gross FCM payments by commitment period. Payments for CCPs 14-18 are projected payments based on FCA outcomes, as those periods have not yet been settled. Payments for incomplete periods, CCP 14 through CCP 18, have been estimated as: $FCA\ Clearing\ Price \times 1{,}000 \times Cleared\ MW \times 12$ for each resource.

Figure 6-5: FCM Payments and FCA Volumes by Commitment Period



Capacity payments have generally trended downwards over the eights auctions, consistent with a surplus of cleared system capacity, but are expected to rise due to a higher clearing price in FCA 18. Capacity charges are grouped together (green bars) and are not visible due to their small scale. Failure-to-Cover charges have affected a small portion of FCM payments since implementation in 2019, with resources only charged a maximum of about $1.0 million per year. Pay-for Performance (PfP) charges have not reduced yearly FCM payments by more than 0.5%. We discuss PfP outcomes for 2023 in detail below.

Pay-for-Performance Outcomes in 2023

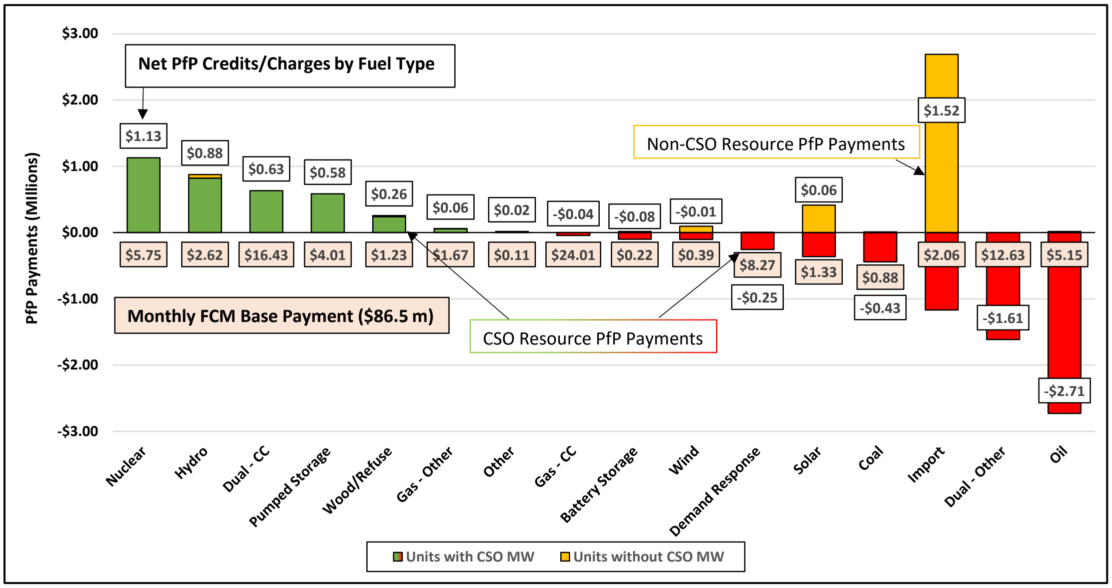
One Pay-for-Performance (PfP) event occurred in 2023, only the third event since the rules were introduced in June 2018. The actual events continue to be significantly fewer than predicted by ISO forecasting models.[255] On July 5, 2023, from 6:25PM to 6:50PM (6 five-minute intervals), system-wide energy supply failed to meet customer load plus the 30-minute reserve requirement. Hotter than expected weather combined with the unexpected loss of over 1,000 MW of imported generation triggered the capacity scarcity condition.

During the event, load and reserve requirements averaged 23,366 MW, or 80% of total contracted capacity (30,281 MW). The average balancing ratio of 80% obligated capacity resources to provide 80% of their CSO position in the form of energy or reserves. Under-performance resulted in $10.9 million in charges, which were transferred to over-performing resources, assets, and import transactions. Capacity market settlements for the July PfP event are aggregated by fuel type, and ranked, in Figure 6-6.[256]

[255] See *Operating Reserve Deficiency Information – Capacity Commitment Period 2023-2024* (February 14, 2020) by Fei Zeng, available at https://www.iso-ne.com/static-assets/documents/2020/02/2020_05_28_pspc_iso_memo_fca_14_operating_reserve_deficiency_info.pdf

[256] In this figure, "Dual" refers to dual-fuel (gas/oil) assets and "CC" refers to combined-cycle assets.

Figure 6-6: Capacity Market Settlements by Fuel Type (July 2023)



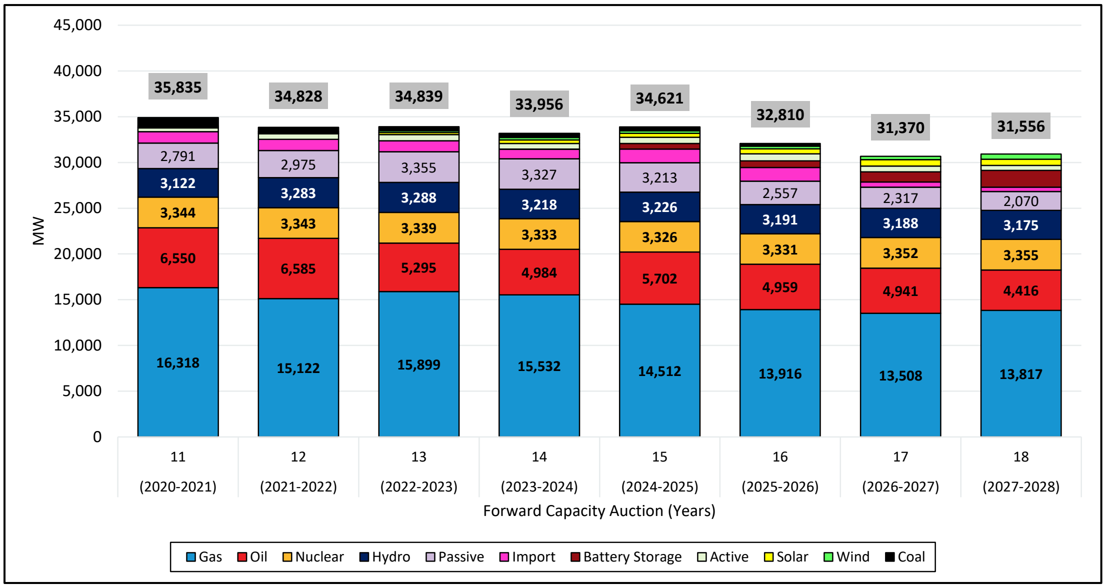
Non-CSO *Import* transactions and *Nuclear* resources were the best performers in the July event, each receiving over $1 million in PfP credits. *Oil-fired* and non-combined-cycle *dual-fuel* resources incurred the most under-performance charges ($4 million combined) due to their economics and their inability to react to short-duration events.[257]

6.2.2 Capacity Resource Mix

There are three categories of capacity resources that can participate in the FCM: generation, demand response and import resources. Capacity by type, including both generation and passive and active demand response, is illustrated in Figure 6-7.

[257] For additional information on the July 5, 2023 PfP Event, see our *Summer 2023 Quarterly Markets Report* (October 27, 2023), Section 2.4, available at https://www.iso-ne.com/static-assets/documents/100004/2023-summer-quarterly-markets-report.pdf

Figure 6-7: Capacity Mix by Fuel Type



FCA 18 reversed a downward trend in total cleared capacity and cleared 31,556 MW, slightly above FCA 17 totals. The increase in cleared capacity aligned with a similar increase in Net ICR, leading to capacity surplus of around 1,000 MW, similar to FCA 17. The figure clearly shows the gradual transition to policy resources such as solar, wind, and batteries over recent years. These resources made up just 0.6% of the capacity mix in FCA 11 but comprised 8.6% of the FCA 18 mix. While policy resources are growing, we see a trend of decreasing levels of energy efficiency, oil generation, and imports in recent years.

Retirement of Capacity Resources

The retirement process is linked to the capacity market qualification process in which resources elect priced or unconditional retirements for a given FCA to exit both the capacity and the energy markets. Retirement elections are published in advance of the FCA so that the market has information to inform new entry decisions.[258] Major retired generating resources, defined here as capacity exceeding 50 MW, from FCA 11 through FCA 18 are shown in Table 6-1 below.

[258] *See ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids and Substitution Auction Demand Bids*, available at https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx

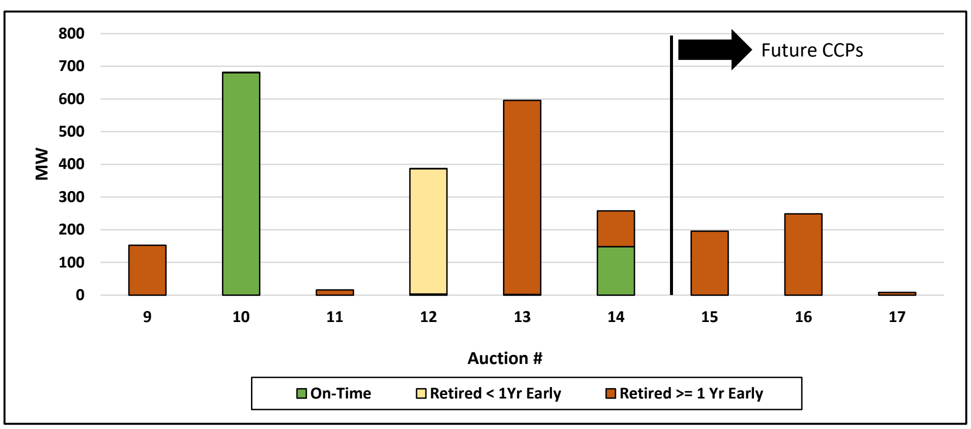
Table 6-1: Generating Resource Retirements over 50 MW[259]

FCA # (Commitment Period)	Resource Name	Fuel Type	Load Zone	Capacity Zone	FCA MW
FCA 12 (2021/22)	**Bridgeport Harbor 3**	**Oil**	**Connecticut**	**Rest-of-Pool**	**383**
FCA 13 (2022/23)	**Mystic 7**	**Oil**	**NEMA/Boston**	**SENE**	**575**
FCA 14 (2023/24)	Yarmouth 1	Oil	Maine	Maine	50
FCA 14 (2023/24)	Yarmouth 2	Oil	Maine	Maine	51
FCA 14 Total (resources > 50 MW)					**101 MW**
FCA 15 (2024/25)	Mystic 9	Gas	NEMA/Boston	SENE	710
FCA 15 (2024/25)	Mystic 8	Gas	NEMA/Boston	SENE	703
FCA 15 (2024/25)	West Springfield 3	Gas	WCMA	Rest-of-Pool	95
FCA 15 (2024/25)	CDECCA	Gas	Connecticut	Rest-of-Pool	52
FCA 15 Total (resources > 50 MW)					**1,560 MW**
FCA 16 (2025/26)	**Potter 2 CC**	**Gas**	**SEMA**	**SENE**	**72**
FCA 18 (2027/28)	MIDDLETOWN 4	Oil	Connecticut	Rest-of-Pool	400
FCA 18 (2027/28)	MIDDLETOWN 2	Oil	Connecticut	Rest-of-Pool	347
FCA 18 (2027/28)	Lowell Power Reactivation	Gas	WCMA	Rest-of-Pool	74
FCA 18 Total (resources > 50 MW)					**821 MW**

Energy policy and market dynamics have increased pressure to retire lower efficiency oil- and gas-fired generators. However, in general, we have seen modest levels of retirement to date, even the retirement of the Mystic generators and others in FCA 15 represented less than 5% of the NICR for that auction. FCA 18 saw the retirement of over 800 MW of oil- and gas-fired resources. The retirement of Middletown 4 was matched with the clearing of a 200 MW battery storage project at the same location.

Since the retirement process commences almost four years prior to the delivery period (CCP), in practice, existing generators nearing retirement have evidenced delivery challenges, in terms of their ability to operate until the FCA delivery period in which they retired. Indeed, some resources may retire (or become inoperable) before retiring through a FCA process. Figure 6-8 below provides a breakdown of retired generation capacity in each FCA by the timeframe when it actually retired.

Figure 6-8: Resource Retirement Timing by FCA



[259] Retirements in FCA 17 are not displayed in the table and totaled only 8 MW.

Of approximately 2,500 MW of retired generation capacity, about 33% (830 MW) retired within close proximity (within one month as captured in the "On-Time" series) of the start of the capacity commitment period (CCP) associated with their retirement. The remaining ~67% (1,710 MW) retired more than one month before the CCP; 15% (390 MW) of the total retired between one month and one year sooner ("Retired < 1 Yr. Early" series), while 52% (1,320 MW) retired a year or more sooner than the CCP associated with their retirement ("Retired >= 1Yr Early" series).

Retirement timings do not always align with capacity commitment periods and remain outside of the publication of information associated with capacity market qualification and results. For example, if a 1,000 MW resource that retired in FCA 18 (2027/2018) experienced a catastrophic equipment failure in 2024, it must notify the ISO through the outage reporting process, but such information is not published to the market.[260] We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants, and we therefore recommend that ISO publish such retirements to the marketplace.

Recommendation

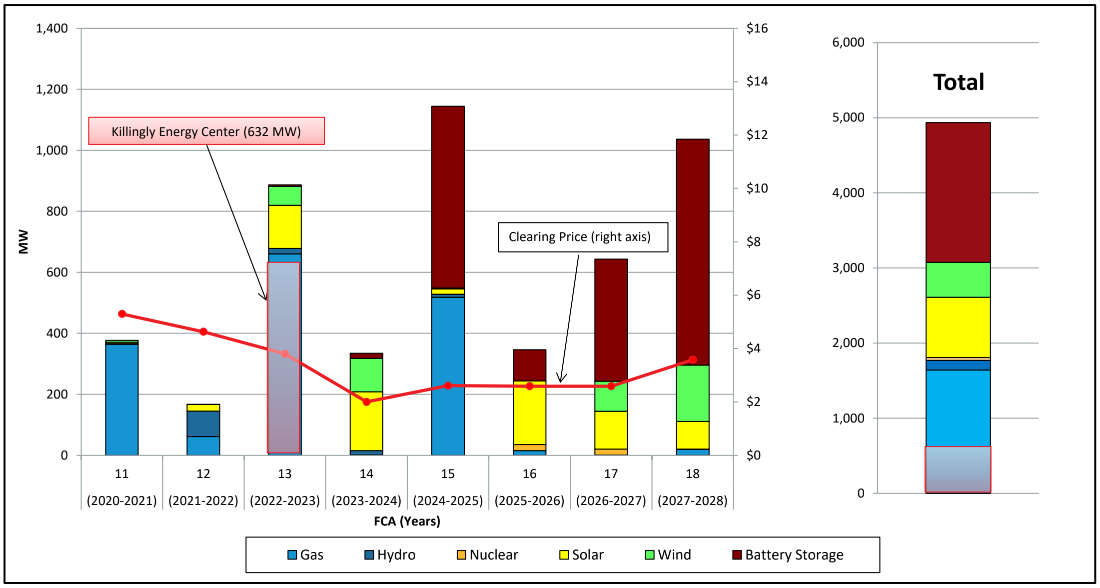
We recommend that the ISO publish generation retirements that have occurred either prior to the effective retirement date in the FCM or outside of the FCM process.

New Entry of Generation Capacity Resources

There has been a significant amount of new entry generation capacity over the past eight auctions, totaling about 5 GW (averaging roughly 620 MW per auction). New generation capacity by fuel type since FCA 11 is shown in Figure 6-9. The shaded grey bars indicate gas capacity that was ultimately terminated due to not realizing commercial operation.

[260] In practice, it is very likely that much of the industry, and in some cases the general public, is aware of major retirements occurring outside of the FCM process. However, the ISO may be currently restricted by its information policy in discussing this information.

Figure 6-9: New Generation Capacity by Fuel Type



Prior to FCA 15, natural gas-fired resources comprised the majority of new additions totaling ~1,000 MW. However, over 630 MW of the new gas-fired capacity was ultimately terminated when Killingly Energy Center failed to meet key development milestones prior to the delivery period of FCA 13. Since FCA 15, renewable energy projects were responsible for 67% of new capacity, largely driven by 1,840 MW of new battery storage projects.

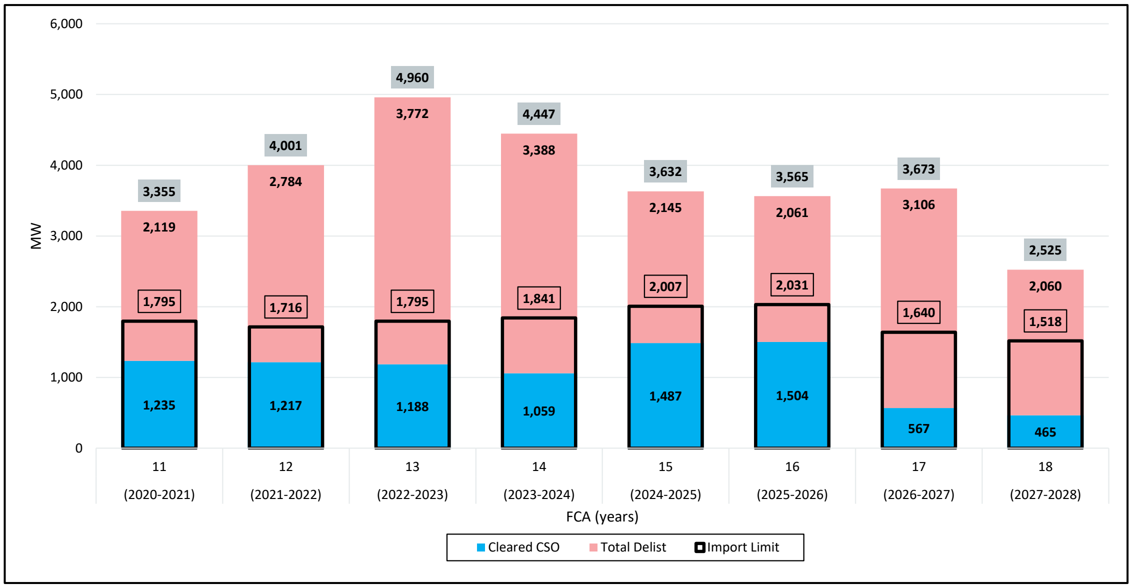
Exit of Import Capacity Resources

From FCA 11-16, the volume of cleared import capacity fluctuated between 1,000 MW to 1,500 MW across the four external ties in the FCM, with most capacity at the New York AC lines (50%) and Phase II (30%). In the past two auctions, cleared import capacity decreased significantly with only 465 MW clearing in FCA 18.

Cleared CSO MW and de-list MW totals from import capacity resources from FCA 11–18 are shown in Figure 6-10 below.[261] The import limit (black line) represents the maximum amount of import capacity that can clear over New England's external interfaces in each FCA.

[261] Import resources using existing tie line capacity are deemed "new capacity" in the market rules. However, from a market power mitigation perspective, import resources are similar to existing capacity resources. We therefore view these resources as essentially de-listing capacity when they exit the market.

Figure 6-10: FCA Import De-list MW



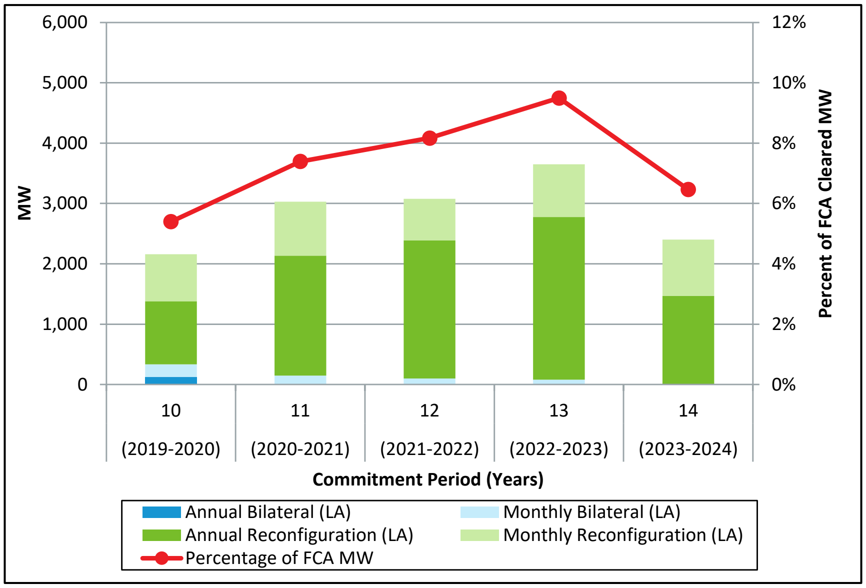
Import capacity de-listed 82% of their qualified capacity in FCA 18, up from 67% on average in FCAs 11-16 and in line with 85% in FCA 17. A key factor driving import resource behavior is the expected price they can receive in their neighboring control areas ("the next best alternative"); if there is a higher likelihood that New York capacity prices will be higher, one would expect less capacity to clear across New York North into New England.

6.2.3 Secondary Forward Capacity Market Results

After each FCA and up to just before the commitment period, resources can adjust their CSOs through a variety of reconfiguration auctions in the secondary market. The average annual volume by secondary market products (stacked bars corresponding to the left axis) and volume as a percentage of cleared volume in the corresponding FCA (red line corresponding to the right axis) are shown in Figure 6-11 below.[262]

[262] Volumes are shown as average annual weighted values. A monthly product gets a weight of 1/12th; an annual product a weight of 1, etc.

Figure 6-11: Traded Volumes in Reconfiguration Auctions



Historically, traded volumes in the secondary markets have been much lower than in the primary auctions. Since CCP 10, the trade volumes as a percentage of FCA volumes have increased steadily, ranging from 6% in CCP 10 to almost 10% in CCP 13. The majority of secondary trading occurs during annual reconfiguration auctions and monthly reconfiguration auctions, with around 2,400 MW traded to date in CCP 14.

Section 7
Ancillary Services

This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. While there are six main types of ancillary services (listed below), this section focuses on real-time operating reserves, forward reserves, and regulation services.

The six main types of ancillary services are:

- *Real-time operating reserves* represent additional generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market (Section 7.1).
- *Forward reserves* represent the procurement of offline operating reserves in advance of the delivery period; that is, the ability to start and ramp quickly in the event of system contingencies (Section 7.2).
- *Regulation service* is provided by resources that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand and maintain system frequency levels in the real-time energy market (Section 7.3).
- *Voltage support* helps the ISO maintain an acceptable range of voltage on the transmission system, and is necessary for the reliable flow of electricity. The ISO regulates voltage through reactive power dispatch, and the generators that provide this service receive voltage support payments.[263]
- *Blackstart service* is provided by generators that are able to start quickly without outside electrical supply. The ISO selects and compensates strategically located generators for providing blackstart service. This service is necessary to facilitate power system restoration in the event of a partial or complete system blackout.

Ancillary service costs by submarket are shown in Figure 7-1 below.[264] The gray boxes above each bar show the total ancillary service cost for each year.

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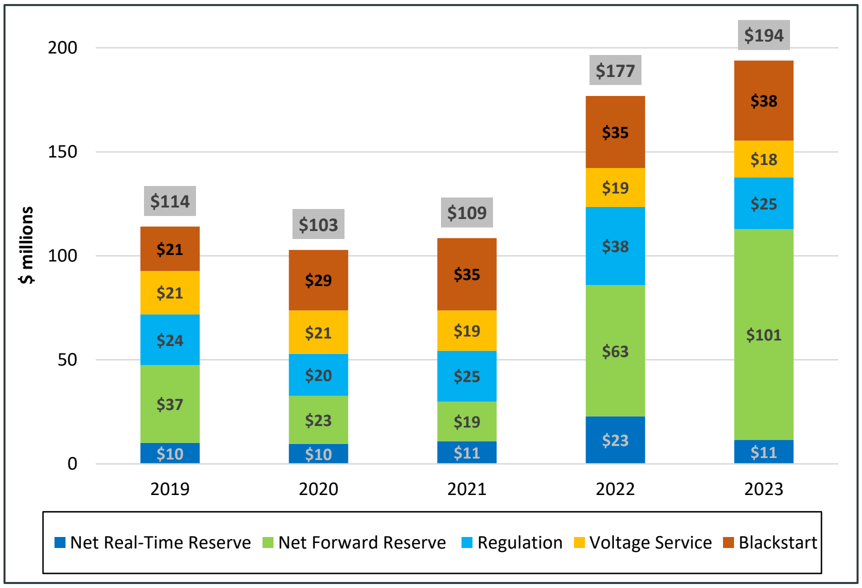
[263] Transmission customers who use regional network service or through-or-out service incur voltage support charges. If the ISO commits a resource for voltage support in the energy market and it does not recover its effective offer, the resource is eligible for NCPC. The ISO Tariff contains detailed rules regarding compensation for voltage support. See *Section II ISO New England Open Access Transmission Tariff (the OATT)*, Schedule 2, available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[264] The Voltage Service category includes payments for capacity costs, lost opportunity costs, costs of energy consumed, and costs of energy produced.

Figure 7-1: Ancillary Service Costs by Product



Overall, ancillary costs in 2023 were the highest over the last five years, totaling $194 million, an increase of 10%, or $17 million, on 2022 ($177 million). The largest increase was in forward reserve costs, which rose by $38.2 million in part due to increased supply offer pricing by participants with resources capable of providing ten-minute non-spinning reserves. Regulation and net real-time reserve costs decreased by $12.8 and $11.3 million, respectively, primarily due to lower energy prices. Blackstart and voltage service costs were similar to 2022 and 2021 costs.

7.1 Real-Time Operating Reserves

The following section reviews real-time operating reserve products and outcomes. The first subsection (7.1.1) presents the reserve requirements that ISO maintains in the real-time energy market as well as the typical amount of reserve capability that is available in excess of those requirements. The second subsection (7.1.2) explores the frequency and magnitude of real-time reserve prices, including the frequency of reserve constraint penalty pricing, and summarizes the level of real-time reserve payments. The final subsection (7.1.3) outlines our recommendation on the application of reserve designations for transmission-constrained resources.

Key Takeaways

The system had ample reserve capability to satisfy reserve requirements throughout 2023. The average system reserve requirements in 2023 were lower than prior years (by 6-15 %), which was largely the result of reduced imports across the Phase II external interface. Total ten-minute and Total thirty-minute reserve margins were lower on average in 2023, partly as a result of extended nuclear and pumped storage outages.

During 2023, net real-time reserve payments totaled $11.5 million, a 50% decrease from 2022 primarily due to a decline in spinning reserve (TMSR) payments. The decrease in TMSR payments was driven by a 40% decrease in non-zero TMSR pricing frequency, which resulted from lower requirements. TMNSR and TMOR reserve payments totaled $7.8 million in 2023, down 5% from 2022.

The activation of reserve constraint penalty factors (RCPFs) remains an infrequent occurrence. On July 5, a reserve deficiency resulted in the activation of total ten- and thirty-minute RCPFs due the trip of the Phase II interconnection and led to capacity scarcity conditions for 30 minutes.

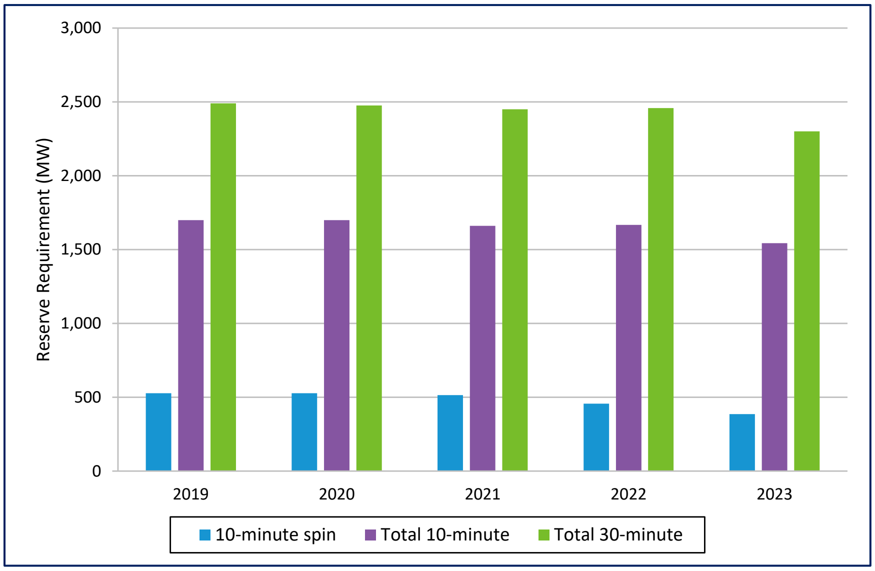
The IMM has identified potential enhancements to the accounting of reserves for resources in export-constrained areas. There are times when the market clearing assumes reserve capability for capacity that is not deliverable. While market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints. We therefore recommend that the ISO establish an automated process for the application of the reserve down flag, to improve reserve accounting and associated market outcomes.

7.1.1 Reserve Requirements and Margins

There are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Reserve requirements are based on the two largest contingencies on the system (commonly known as first and second contingencies). Figure 7-2 shows these system level requirements.[265]

[265] There are also 30-minute local reserve requirements that are not shown or discussed below. These requirements bind infrequently, and showed no discernable trends during the reporting period.

Figure 7-2: Average System Reserve Requirements



The average total ten-minute reserve requirement was 1,544 MW in 2023, down 7% from 2022. This decrease was driven by reduced imports across the Phase II DC tie with Hydro-Quebec, resulting in that source of energy supply being the largest contingency less frequently during 2023 (42% of hours) than in prior years (83%-92% of hours).[266] The total thirty-minute reserve requirement (2,301 MW) is also driven in part by the size of the largest contingency, and saw a similar reduction as a result. The average ten-minute spinning reserve requirement (387 MW) decreased by 15% from its average value in 2022 (456 MW). This decrease resulted from two factors: (1) the smaller first contingency value due to decreased flows on Phase II, and (2) the ten-minute spinning reserve requirement being set at 25% of the total ten-minute requirement throughout 2023. This is the minimum ten-minute spinning requirement percentage allowed by NERC and NPCC guidelines.[267] In prior years, this percentage was periodically set at higher values.

The reserve margin measures the reserve capability available in excess of reserve requirements. On average, there has been a healthy surplus of reserve capability on the system compared to the requirements, and relatively few instances where the system experienced a deficiency of capacity or reserves. These instances are included in the discussion of interesting system events in Section 3.6.

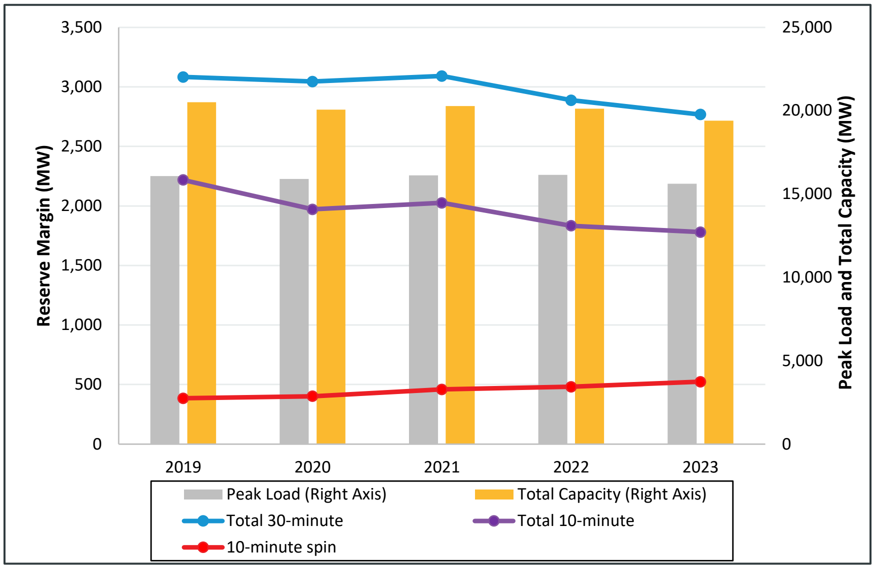
The annual average margins for ten-minute spin reserves (red line), total ten-minute reserves (purple line), and total thirty-minute reserves (blue line) are shown in Figure 7-3 below. The margins are equal to the amount of reserves provided in excess of the corresponding reserve requirement. The bars represent annual average load (gray bar) and available capacity (orange

[266] As a result, the Seabrook nuclear plant was the largest contingency in 46% of hours in 2023, a higher percentage than in prior years.

[267] The operational decision to change this percentage stemmed from changes to the reserve designation rules for composite resources, which provide more accurate accounting of TMSR supplied by those resources.

bar) during the peak hour of each day.[268] Combined, these bars show the difference between load and available capacity, which is when reserve margins are typically at their lowest.

Figure 7-3: System Reserve Margin, Peak Load, and Available Capacity



The average total ten-minute reserve margin declined by 53 MW (3%) and the average total thirty-minute reserve margin declined by 120 MW (4%) in 2023. There were several drivers for these declines. Extended outages of nuclear generation and decreased net imports into the region resulted in increased energy dispatch of natural gas and hydro generators. These resource types typically provide reserves on unloaded portions of their resources, and when their energy dispatch increases, the quantity of reserves they are able to provide decreases. In addition, outages of pumped-storage generators, which are a significant supply of offline reserve capability, contributed to these decreased margins.

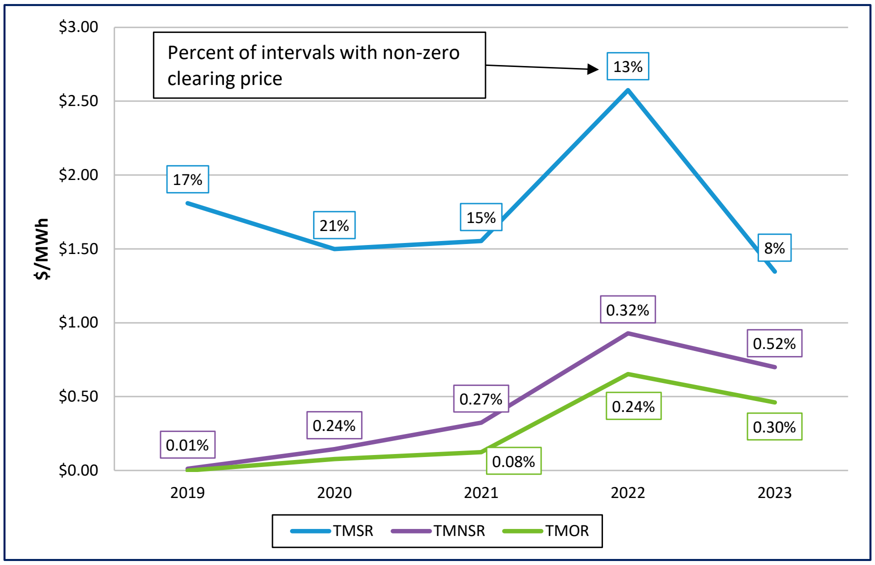
The 10-minute spin margin increased by 42 MW (9%) in 2023 because that reserve requirement declined after operational tool enhancements were made in mid-2022.

7.1.2 Reserve Prices and Payments

Reserve prices occur only when there is an opportunity cost of providing reserves rather than energy; in other words, when the market clearing engine must re-dispatch resources to maintain reserve requirements. This is an infrequent occurrence in New England, which has a large fleet of offline fast-start resources. Most of the time such re-dispatch is not necessary and, as a result of the reserve constraint not binding, reserve clearing prices are $0/MWh. Figure 7-4 below shows both the frequency of non-zero reserve prices and the average value of reserve prices for all products at the system level.

[268] Available capacity is the generation capacity that can be delivered within a 30 minute period: $Gen_{Energy} + Gen_{Reserves} + [Imports - Exports]$

Figure 7-4: Reserve Price Frequency and Average Value



In 2023, TMSR pricing was non-zero in 8% of all intervals, down from 2022, and in line with the lower TMSR requirement. TMNSR and TMOR were $0/MWh in the vast majority of intervals, keeping with historical trends.

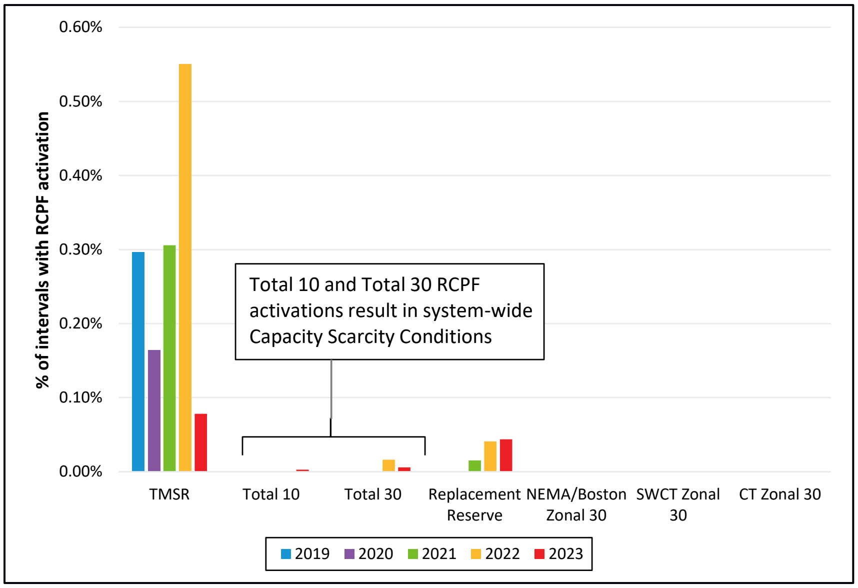
Average TMSR prices decreased by 48%, from $2.57/MWh in 2022 to $1.35/MWh in 2023. Average TMNSR and TMOR prices also decreased. In 2023, average TMNSR prices were $0.70/MWh and average TMOR prices were $0.46/MWh.

In 2023, a local thirty-minute reserve constraint bound in only two five-minute pricing intervals, and only for the NEMA/Boston reserve zone. This resulted in higher TMSR, TMNSR, and TMOR clearing prices within the NEMA/Boston zone than at the system level in those two intervals.

Reserve Constraint Penalty Factors (RCPFs)

RCPFs for reserve constraints are "activated" and impact reserve prices when there is insufficient reserve capability to meet the reserve requirements, or when the cost of re-dispatch to satisfy those requirements exceeds RCPF values. The percentage of five-minute intervals during which the RCPF for each reserve constraint was activated is shown in Figure 7-5 below.

Figure 7-5: Reserve Constraint Penalty Factor Activation Frequency



Overall, the low level of reserve scarcity is consistent with high reserve margins in recent years. In 2023, the RCPF for TMSR activated in 0.08% of total intervals, or for roughly 7 hours of the year. The TMSR RCPF activated more frequently than the RCPFs of other reserve constraints due to its relatively low value ($50/MWh). The replacement reserve RCPF ($250/MWh) activated in 46 five-minute intervals (3.8 hours).

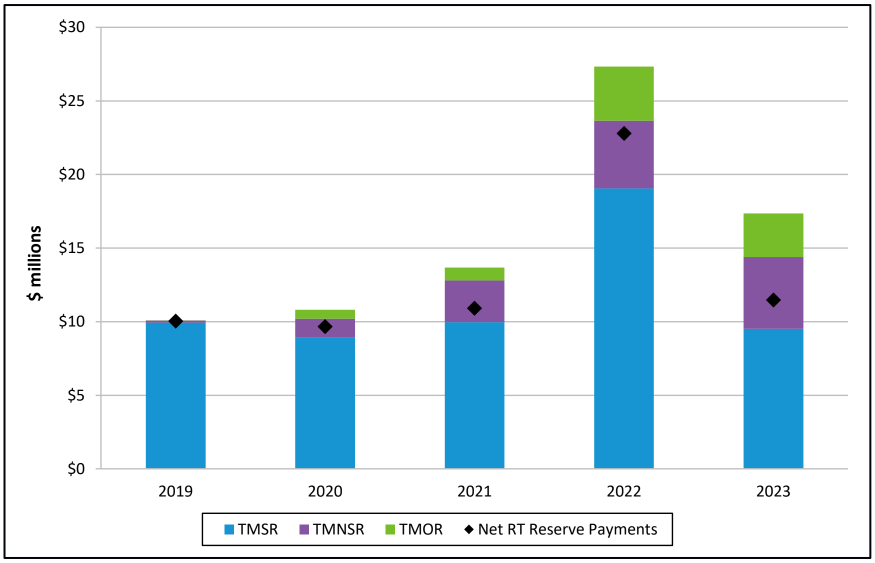
During the July 5 system event, which was caused by the unexpected outage of the Phase II interconnection, there were six intervals (30 minutes) in which the minimum total thirty-minute reserve constraint RCPF ($1,000/MWh) activated, and three intervals in which the total ten-minute reserve constraint RCPF ($1,500/MWh) activated. Because of these activations, there was a capacity scarcity condition under the Forward Capacity Market's pay-for-performance rules, which is discussed further in Section 6.2.

Reserve Payments

Real-time reserve payments are made to resources designated to provide operating reserves in intervals when reserve clearing prices are non-zero. Total real-time reserve payments are relatively small compared to overall energy market and capacity market payments.

Figure 7-6 below shows the total payments made for real-time reserves over the past five years, as illustrated by the stacked bars. The black diamond shows total net real-time reserve payments, and is reflective of the elimination of real-time reserve credits to forward reserve resources to ensure these resources are not double-compensated.

Figure 7-6: Real-Time Reserve Payments



Total gross real-time reserve payments in 2023 totaled $17.4 million. These gross payments were reduced by $5.9 million for resources with a forward reserve market obligation, resulting in net real-time reserve payments of $11.5 million.[269] This is a 50% decrease from 2022, and these net real-time reserve payments are approximately 0.1% of total wholesale market costs. More than half of the net real-time reserve payments in 2023 were made during Q4, coinciding with the planned outage of a pumped-storage hydro resource.

The most notable change in 2023 was a 50% decrease in TMSR payments. Non-zero TMSR pricing occurred 40% less often due to a decrease in the TMSR requirement, as noted above. TMNSR and TMOR payments in 2023 were similar to 2022.

Fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over 300% in 2023. A detailed assessment of the impact of fast-start pricing in provided in Section 3.1.2 of this report.

7.1.3 Reserve Designations on Transmission-Constrained Resources

Resources in New England are not eligible to provide operating reserves if constrained by transmission limitations.[270] In practice, this is achieved through a manual process performed by system operators. When a transmission constraint is activated, operators are tasked with applying a 'reserve down' flag to resources limited by that constraint. ISO dispatch software will not designate reserves on units that have the reserve down flag applied. This reflects the fact that, due to the transmission constraint, the reserves that would normally be counted on such resources are not deliverable to the system as energy.

The manual nature of the process to apply the reserve down flag can lead to variability in its application. There may be instances when operators are occupied with more pressing tasks, and there may be imprecision regarding when and how to apply the flag, particularly when the

[269] Section 7.2.3 discusses FRM payments. For reference, net FRM payments in 2023 were roughly $101.4 million.

[270] See *Section III Market Rule 1 Standard Market Design*, Section III.1.7.19.1(3), available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

number of resources in a constrained area is large. This may result in the following market impacts.

First, the reserve down flag can impact reserve clearing prices. The quantity of available reserves directly affects reserve clearing prices. There may be instances when the 'correct' reserve clearing price is lower than the actual reserve clearing price, based on how the reserve down flag is applied. For example, if the reserve down flag is not applied to resources in a constrained area for one or more pricing intervals, then the actual reserve price may be lower than it should have been during those intervals because more reserves were counted than could be delivered. As a result of this pricing impact, the reserve settlement for all resources providing reserves will be affected. In addition, certain resources may receive reserve payments that are unwarranted if the reserve down flag is not applied during an interval when it should be applied. Finally, because of the interrelationship between real-time LMPs and reserve prices, it is possible that real-time LMPs would also be affected by this issue.

To study this issue, we examined instances over a recent three-year period when transmission constraints were binding in real-time, and the aggregate reserve quantity designated on resources behind those constraints exceeded the transmission limit. We estimated the number of intervals in which reserve prices would have been higher if the reserve down flag had been applied to these resources. We also estimated the magnitude of reserve payments to these transmission-constrained resources.[271]

Reserve price formation is moderately impacted by this issue, as shown in Table 7-1 below. In this table, the hour values displayed represent the aggregation of five-minute pricing intervals (not discrete clock-hours).

Table 7-1: Reserve down flag impacts to reserve clearing price (RCP)

Year	Historical hours with non-zero RCP	Hours which would have had higher RCP	% Increase relative to historical non-zero hours	Hours that change from RCP = $0 to RCP > $0	% Increase relative to historical non-zero hours
TMSR					
2021	1,340	192	14%	21.5	2%
2022	1,178	74	6%	10.8	1%
2023	707	59	8%	14.5	2%
TMNSR					
2021	24	3	13%	0	0%
2022	28	2.8	10%	0.1	0%
2023	46	2.5	5%	0.4	1%
TMOR					
2021	7	2.2	31%	0.4	6%
2022	21	2.1	10%	0.1	0%
2023	26	0.8	3%	0.3	1%

[271] The calculations used to derive these estimates consider the pre-contingency line limits in effect in the ISO's dispatch and pricing software, and do not account for changes to these limits that could occur post-contingency.

Reserve prices would have been higher in a moderate number of intervals if the reserve down flag had been applied to the resources identified in this study that were behind binding export constraints. Consider TMSR, for instance. In 2021, application of the reserve down flag to the identified transmission-constrained resources would have resulted in increased TMSR RCPs in 192 hours, an increase of 14%. In 21.5 of these hours, the TMSR RCP would have transitioned from $0/MWh to a non-zero value with the reserve down flag applied. This represents 2% of hours in that year when both reserve and energy prices may have been higher, had it been possible to more accurately designate reserves. The impact varies by reserve product and year. TMNSR and TMOR pricing is less common than TMSR pricing, but results show that the percent of hours which would have had higher prices are similar for those two products as for TMSR.

Table 7-2 displays the total reserve payments made to identified resources in export-constrained areas (i.e., those resources that could not actually provide reserves if needed), in the context of overall annual real-time reserve credits.

Table 7-2: Real-time reserve payments to identified resources behind binding export constraints

Year	Total RT Reserve Credits ($M)	RT Reserve Payment to Constrained Resources ($M)	Percent of Total
2021	$13.7	$0.02	0.1%
2022	$27.3	$0.32	1.2%
2023	$17.4	$0.01	0.1%

Reserve payments to identified resources in constrained areas occur consistently each year, but reflect a very small portion of the overall payments for reserves (0.1% - 1.2% annually).

While market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints.

Recommendation

We recommend that the ISO establish an automated process for the application of the reserve down flag, to improve reserve accounting and associated market outcomes.

7.2 Forward Reserves

Here, we assess outcomes in the Forward Reserve Market (FRM), which procures reserve products in advance of summer and winter seasons. Specifically, in this section we review the trends in auction demand quantities over the past five years (7.2.1), auction results (7.2.2), and the resulting levels of forward reserve payments (7.2.3).

> ***Key Takeaways***
>
> Over the last few years, the quantities of reserve capability required in the FRM have been reasonably stable at the system level. Additionally, there has been no need for a local requirement in any local reserve zone due to transmission improvements.
>
> While auction clearing prices prior to Summer 2022 had been below $2,000/MW-month, the auctions since then have seen increasing clearing prices. The Summer 2022 auction, in particular, had TMNSR prices of $7,386/MW-month, reflecting a significant increase in participant offer prices. Similarly, the Summer 2023 auction had TMNSR and TMOR prices of $7,499/MW-month. Given the increase in recent auction clearing prices, as well as the continued evidence of structural market power, the IMM recommended that the ISO review and update the forward reserve offer cap.
>
> FRM payments significantly exceed real-time operating reserve payments reflecting significantly different structures between these forward and spot markets. While FRM payments had declined between 2019 to 2021, increased auction clearing prices in 2022 and 2023 resulted in large increases in net FRM payments ($19.0 million in 2021 to $101.4 million in 2023).

7.2.1 Market Requirements

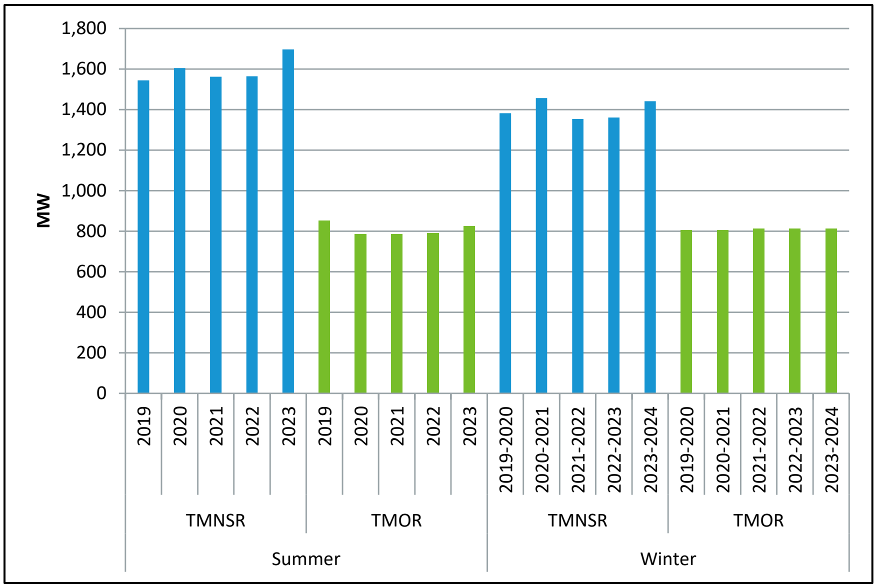
The FRM auction procures ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) on a forward basis. The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for each procurement period. In addition to developing reserve requirements at the system level, the ISO develops reserve requirements at a zonal level as some zones within New England are constrained in terms of how much power they can import from other zones.[272]

System Requirements

Similar to real-time operating reserve requirements, the system FRM requirements have been reasonably stable during the last five years. This can be seen in in Figure 7-7 below, which shows the system requirements from Summer 2019 through Winter 2023-24.

[272] The currently defined reserve zones are Southwest Connecticut, Connecticut, and NEMA/Boston. See *ISO New England Manual for Forward Reserve and Real-Time* Reserve *Manual M-36* (effective date: December 3, 2019) , Section 2.2.1, available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf

Figure 7-7: Forward Reserve Market System-wide Requirements



Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9, Seabrook, or Millstone.[273] Therefore, the requirements have been relatively consistent around 1,350-1,700 MW for TMNSR and around 800 MW for TMOR. The reasonably small fluctuations in seasonal requirements reflect seasonal variation in the expected capabilities of the resources identified as the system contingencies, and relatively stable expectations for non-spinning reserve needs (affecting TMNSR), generator performance when called upon for system contingencies (affecting TMNSR), and replacement reserve needs (affecting TMOR).

Zonal Requirements

During the last ten auctions, there have been no zonal reserve requirements because there has been sufficient external reserve support (ERS) to alleviate the need for these requirements.[274] This results from a considerable increase in ERS for Connecticut and Southwest Connecticut due mainly to transmission upgrades. Similarly, transmission upgrades in NEMA/Boston have increased ERS for that area, resulting in no need for a local requirement in the last five summer and winter periods.

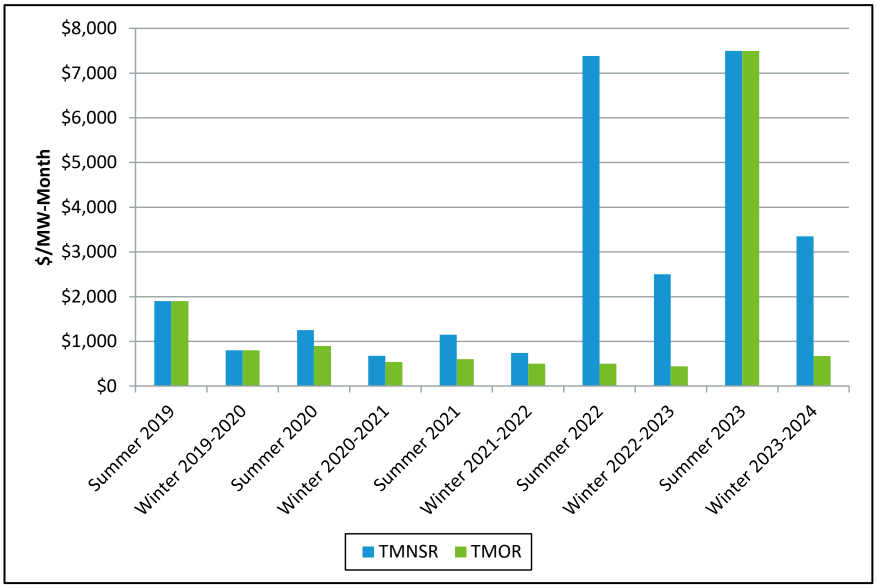
[273] As noted in the ISO's assumptions memoranda for the individual FRM auctions, the FRM system requirements also may be biased up or down and, in the case of TMOR, include a replacement reserve adjustment. See: https://www.iso-ne.com/markets-operations/markets/reserves/?document-type=Forward Reserve Market Assumptions

[274] External reserve support (ERS) refers to the ability of a local reserve zone to obtain operating reserves from other reserve zones. The ERS reflects the amount of available transfer capability on the transmission interface for the local reserve zone. See *ISO New England Manual for Forward Reserve and Real-Time* Reserve *Manual M-36* (effective date: December 3, 2019) , Section 2.2.4, available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf

7.2.2 Auction Results

FRM auction pricing outcomes from the Summer 2019 auction through the Winter 2023-24 auction are shown in Figure 7-8 below.[275]

Figure 7-8: Forward Reserve Prices by FRM Procurement Period



TMNSR and TMOR clearing prices were fairly stable through the review period until the Summer 2022 auction when the TMNSR clearing price increased drastically, rising from $1,150/MW-month in Summer 2021 to $7,386/MW-month in Summer 2022. TMNSR prices have remained elevated in all subsequent auctions, reaching $2,500/MW-month in Winter 2022-23, $7,499/MW-month in Summer 2023, and $3,350/MW-month in Winter 2023-34. TMOR prices also experienced a sharp price increase in the Summer 2023 auction, climbing from $499/MW-month in the Summer 2022 auction to $7,499/MW-month in the Summer 2023 auction. These high auction clearing prices, which generally reflect increased offer prices, in combination with structural market power concerns,[276] led the IMM to recommend that the forward reserve offer cap price be reviewed and updated.[277]

7.2.3 FRM Payments

Annual FRM payment and penalty data over the past five years are provided in Figure 7-9 below. The figure indicates the annual auction-based payments, which are based on auction obligations and auction clearing prices, as positive stacked bar values. Meanwhile, penalties are shown as negative stacked bar values. FRM participants face two types of penalties: (1) failure-to-reserve (FTR) penalties, which occur when a participant's assignments to resources are less than the participant's FRM obligation, and (2) failure-to-activate (FTA) penalties, which occur

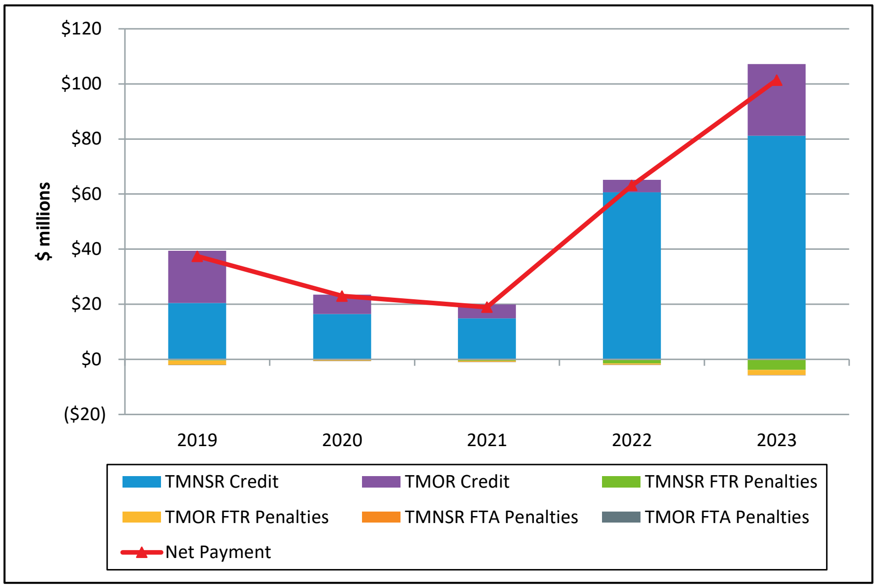
[275] Because there were no zonal reserve requirements, the clearing prices for each reserve product apply to all cleared supply offers for that product regardless of the zone associated with the offer.

[276] See Section 2.6.1 for more information related to the competitiveness of the Forward Reserve Market.

[277] The IMM's recommendation related to the forward reserve offer cap can be found in our *Spring 2023 Quarterly Markets Report* (August 1, 2023), Section 5.3.3: https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf

when a resource that has been assigned an FRM obligation fails to provide energy when called upon by the ISO. The net payment is depicted by the red line.

Figure 7-9: FRM Payments and Penalties by Year



Net forward reserve payments increased significantly, rising from $63.2 million in 2022 to $101.4 million in 2023. This was due to the higher TMNSR and TMOR auction clearing prices discussed previously. Total TMNSR credits in 2023 amounted to $81.2 million, while total TMOR credits in 2023 amounted to $26.0 million. Both of these values were the highest of the reporting period. Meanwhile, penalties have been low relative to gross payments and have been stable in the 2% to 5% range of total payments over the period. These penalties have been predominately for failing to reserve (96%). Since failure-to-reserve penalties result in forfeiture of auction-based payments for unassigned obligations, the payments are directly influenced by FRM clearing prices. Total penalties increased by 197% to $5.8 million in 2023 (when FRM clearing prices significantly increased).

7.3 Regulation

In this section, we examine the participation, outcomes, and competitiveness of the regulation market. Specifically, we review the amount of regulation capability needed by the ISO (7.3.1), and regulation clearing prices and payments (7.3.2).

Key Takeaways

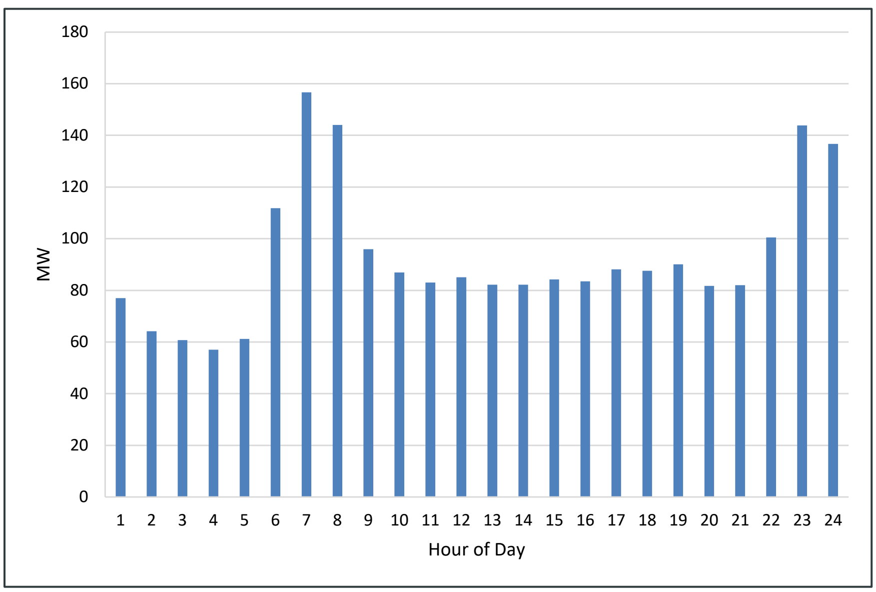
Regulation requirements in 2023 were similar to 2022, averaging just over 90 MW of regulation capacity per hour. The resource mix of cleared regulation capacity has changed significantly over the review period. In 2019, alternative technology regulation resources (mainly batteries) accounted for 15% of cleared capacity. In 2023, these resources accounted for 62% of cleared capacity.

The regulation market produces two clearing prices: for capacity and service. Clearing prices for capacity, which made up about 90% of the overall market value, decreased from $30.96/MWh in 2022 to $23.48/MWh in 2023, reflecting a decrease in energy market opportunity costs. Regulation service prices decreased from $0.27/mile in 2022 to $0.13/mile in 2023. Regulation payments decreased by 40% in 2023, reflecting the decrease in capacity and service prices. Regulation payments in 2023 totaled $25.1 million, compared to $38.4 million in 2022.

7.3.1 Regulation Requirements, Resource Mix, and Performance

The regulation *requirement* in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2023 is shown in Figure 7-10 below.

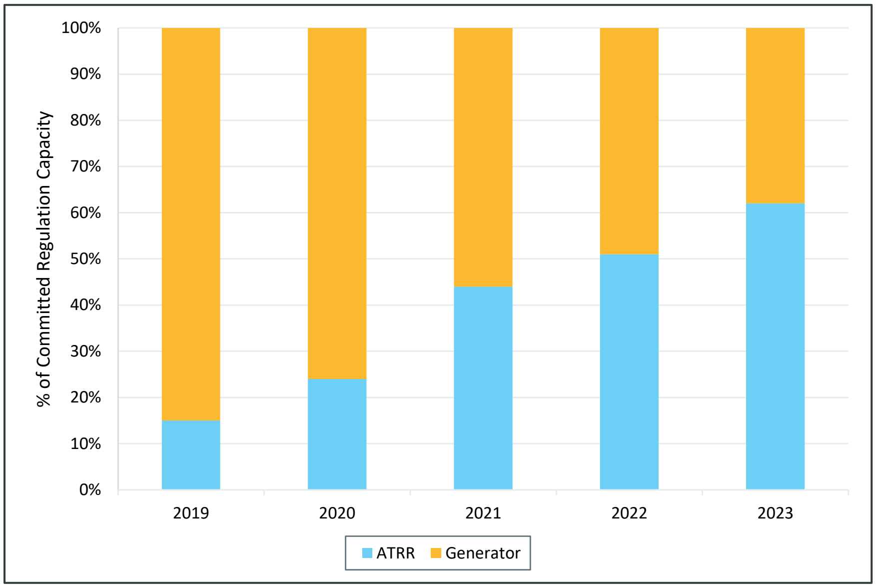
Figure 7-10: Average Hourly Regulation Requirement, 2023



The average hourly regulation requirement was 92.8 MW in 2023, a negligible change from the 2022 requirement (91.2 MW). Two different types of resources can provide regulation in the ISO's regulation market: traditional generators and alternative technology regulation resources (ATRRs). Almost all of the ATRRs are battery resources that may function solely as regulation resources or may operate as a combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation.

The regulation market resource mix for 2019 to 2023 is shown in Figure 7-11.

Figure 7-11: Regulation Resource Mix



The *resource mix* for regulation has changed significantly. In 2019, ATRRs (blue shading) provided 15% of cleared regulation capacity. By 2023, ATRRs provided 62%. This change follows continuing increases in the installed capacity of battery resources in the ISO's markets. Regulation capacity available from ATRRs has increased from 34 MW to 185 MW over the period. The change in resource mix also suggests that battery resources are lower-cost regulation resources (i.e., have lower-cost regulation market offers), as these ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

Finally, regulation *performance* is measured relative to a NERC standard. With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO uses violations of Balancing Authority ACE Limits (BAAL) to measure performance, which are defined as exceedances of ACE limits for more than 30 consecutive minutes. In 2023, there were no BAAL violations.

7.3.2 Regulation Prices and Payments

Regulation Clearing Prices (RCP) are based on the regulation offer of the highest-priced generator providing the service. There are two types of regulation clearing prices: "service" and "capacity."[278] Clearing prices for the past five years are shown in Table 7-3 below.[279]

[278] The service price represents the direct cost of providing the regulation service (also known as regulation "mileage"). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service. The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service, (2) the value of intertemporal opportunities that would be lost from providing regulation, (3) elements of fixed costs such as incremental maintenance to ensure a generator's continued performance when providing regulation, and (4) fuel market or other risks associated with providing regulation.

[279] The prices in the table are simple average prices for each year.

Table 7-3: Regulation Prices

Year	Regulation Capacity Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)		
	Min	Avg	Max	Min	Avg	Max
2019	0.75	21.96	258.67	0.00	0.28	10.00
2020	0.40	16.12	396.08	0.00	0.21	10.00
2021	0.00	19.23	699.11	0.00	0.21	10.00
2022	0.00	30.96	1,068.09	0.00	0.27	10.00
2023	0.00	23.48	649.11	0.00	0.13	10.00

Regulation capacity prices decreased by 24% in 2023, reflecting a decrease in the "opportunity cost" component of regulation capacity pricing.[280] The decrease in opportunity costs is consistent with lower real-time energy market LMPs, which decreased by 58% in 2023 compared to 2022. Lower opportunity costs were partially offset by a small increase in the "incremental cost saving" component (up 6%), which reflects the cost difference between the marginal offer and the next most expensive offer.

Regulation service prices also decreased compared to 2022. In 2023, the average service price was $0.13/mile, down $0.14/mile compared to the prior year. The service price was lower relative to earlier periods due to the increased participation of ATRRs in the regulation market, which often offer at $0/mile.

Regulation Payments

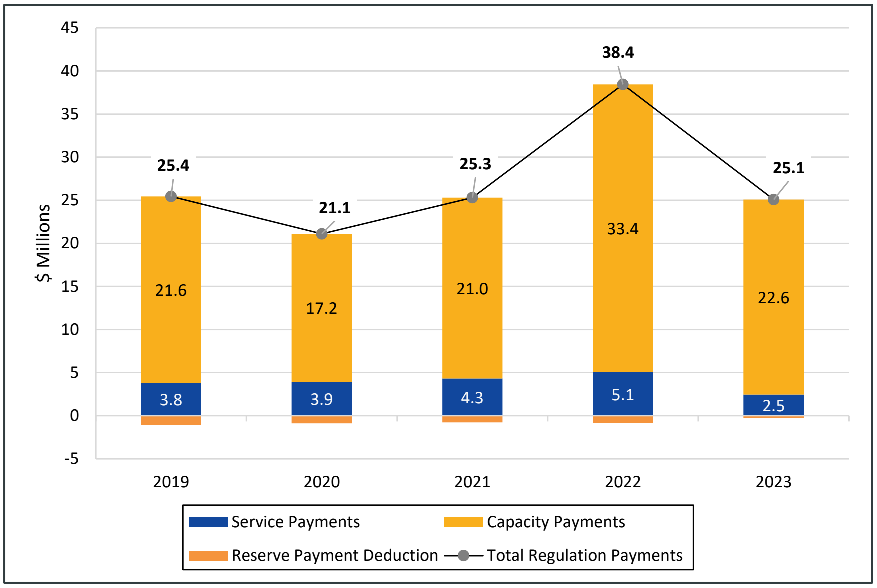
Compensation to generators providing regulation includes a regulation capacity payment, a service payment, a make-whole payment, and an operating reserve adjustment.[281] Annual regulation payments over the past five years are shown in Figure 7-12 below.[282]

[280] The opportunity cost component of the regulation price indicates the expected value of foregone energy market opportunities when providing regulation.

[281] The operating reserve adjustment represents a deduction to regulation payments. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since generators do not actually provide operating reserves within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

[282] The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period. The make-whole payment is included in capacity payment totals, since it represents an uplift payment when the capacity payments do not fully compensate resources for energy market opportunity costs.

Figure 7-12: Regulation Payments



Payments to regulation resources totaled $25.1 million in 2023, 35% less than the $38.4 million in 2022 (these totals exclude the reserve payment adjustment). The decrease in 2023 payments resulted primarily from a 38% decrease in capacity payments, consistent with the above-noted decrease in capacity prices (24%). Lower regulation service prices and payments ($2.8 million decrease in service payments) in 2023 also contributed to the overall decrease in regulation payments. Capacity payments made up 81% to 90% of overall regulation payments during the reporting period.

Section 8
Transmission Congestion and Financial Transmission Rights

This section covers trends in and drivers of transmission congestion and financial transmission rights (FTRs), the financial tools used to manage congestion risk or take positions on congestion.

8.1 Transmission Congestion

Below, we examine transmission congestion in New England over the last five years. We first look at the level of congestion revenue and then explore where the congestion is occurring in the New England power system.

> ***Key Takeaways***
>
> Levels of transmission congestion are relatively low in New England compared to other ISO markets due to the significant amount of transmission investment over the past decade, while transmission rates in New England are relatively high.[283]
>
> In 2023, congestion revenue totaled $32.3 million, representing only 0.67% of total energy costs. This low level of congestion revenue was partly driven by lower energy prices and a generally unconstrained transmission system. That being said, there are some specific areas on the New England System that regularly experience transmission congestion; often in areas with relatively high concentrations of wind generation as well as the main interconnection interface with New York.

Congestion Revenue

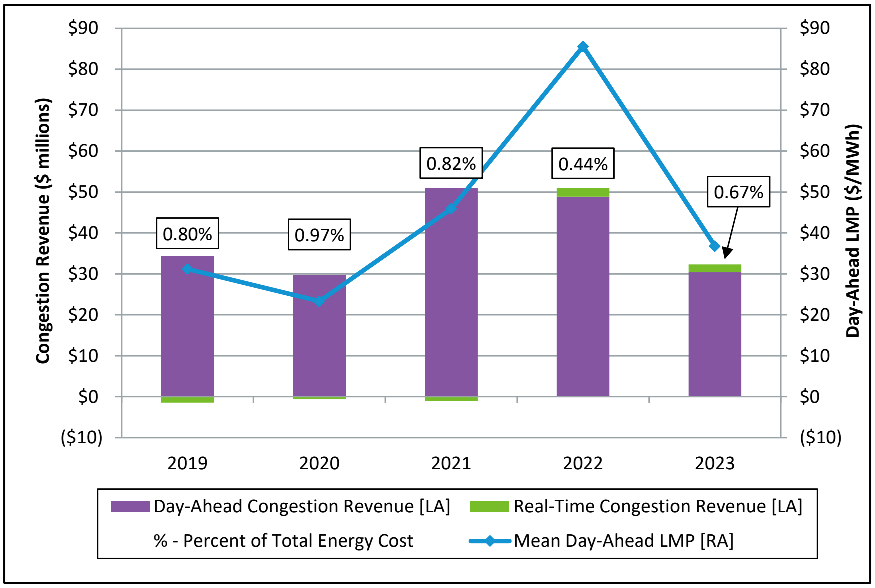
Put simply, congestion revenue represents the difference between what load pays for energy and what generation receives for energy that happens because of transmission congestion.[284] A feature of New England's locational energy market is that load pays for energy at the price where it is *consumed* and generation is paid at the price where it is *produced*. This means that, when there is a binding transmission constraint limiting the production of cheaper generation, load will often pay more for the energy that it consumes than generation receives for the energy that it produces.

[283] Potomac Economics' (The External Market Monitor for ISO-NE) *2022 Assessment of the ISO New England Electricity Markets* (June 2023) showed that ISO-NE had the lowest congestion rate between 2020-2022 ($0.37/MWh) of ERCOT, MISO, PJM, and NYISO, but had the highest transmission rate in 2022 ($22.2/MWh) of these RTOs. See Figure 2 in its *2022 Assessment*¸ available at https://www.potomaceconomics.com/wp-content/uploads/2023/06/ISO-NE-2022-EMM-Report_Final.pdf

[284] For an exact definition of day-ahead and real-time congestion revenue, see *Section III Market Rule 1 Standard Market Design*, Section III.3.2.1(i), available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Over the last five years, congestion revenue has been small relative to total energy market payments, and it has generally moved in line with the price of energy. This can be seen in Figure 8-1 below.[285]

Figure 8-1: Average Day-Ahead Hub LMP, Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $32.3 million in 2023, or just 0.67% of total energy costs. Nearly all of the congestion revenue stems from the day-ahead market ($30.4 million, 94%) where the vast majority of load and generation clear. Real-time congestion revenue tends to be much smaller given that it is based on real-time energy market *deviations* ($1.9 million, 6%). As can be seen in the figure, the day-ahead congestion revenue totals tend to be strongly correlated with the average day-ahead Hub LMP.

Congested Areas in New England

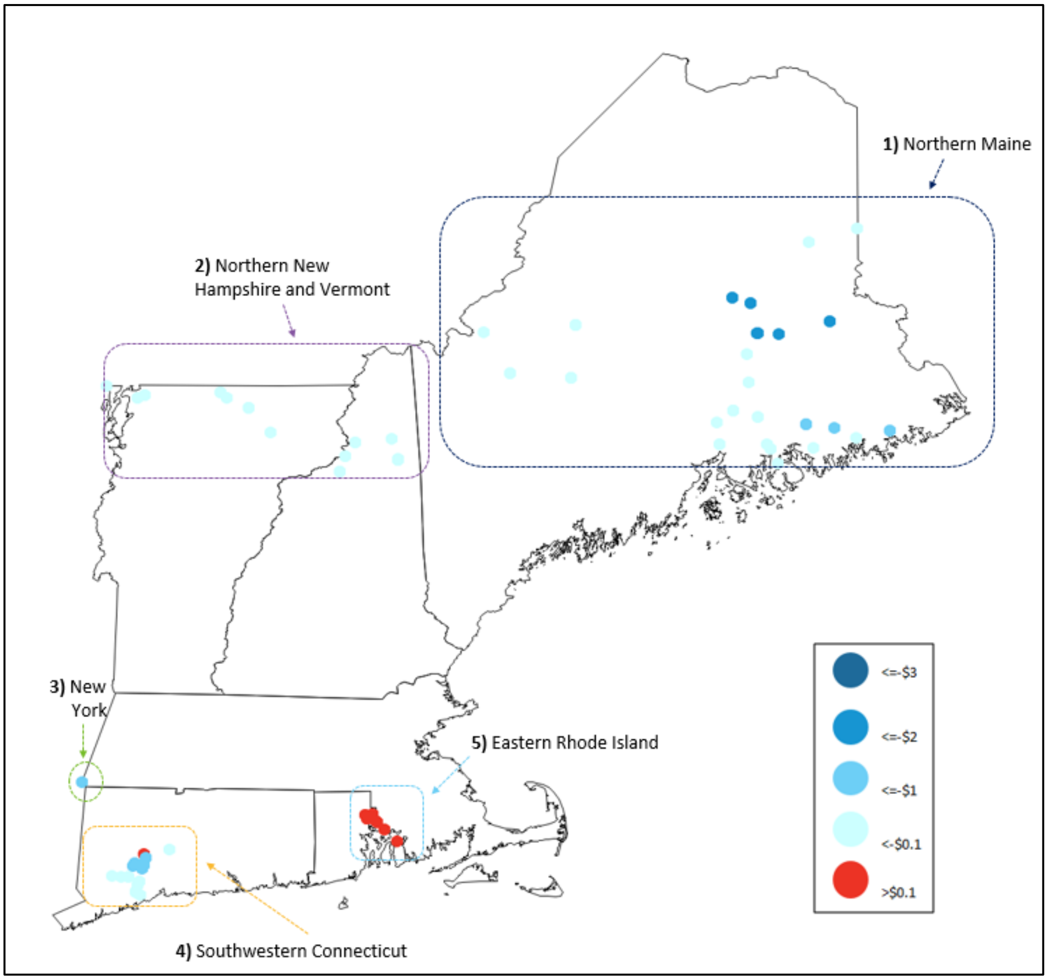
The New England nodes most affected by transmission congestion in the day-ahead market in 2023 are shown in Figure 8-2 below.[286] Locations that are "upstream" of a binding transmission constraint have a negative congestion component.[287] Locations that are "downstream" of a binding constraint have a positive congestion component.

[285] The percentages in the figure are the total congestion revenue each year (i.e., the day-ahead congestion revenue plus the real-time congestion revenue) expressed as a percent of total energy market costs.

[286] In order to highlight the constrained areas, this figure only includes nodes that had an average day-ahead congestion component in 2023 of greater than or equal to $0.10/MWh or less than or equal to -$0.10/MWh.

[287] More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint. Conversely, a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In simple terms, a shift factor measures how an injection of energy at a location impacts the flow of energy over a transmission constraint.

Figure 8-2: New England Pricing Nodes Most Affected by Congestion, 2023



Many of the congested areas in New England in 2023 were relatively small geographic areas where transmission capacity limited the ability to export power to the rest of the system. Several areas in Figure 8-2 have been highlighted and each of them is discussed in detail below:

1) **Northern Maine**: This area has a relatively high concentration of intermittent (predominantly wind) generators and is also where the New England system interconnects to the New Brunswick control area (i.e., imports from New Brunswick flow into this area).

2) **Northern New Hampshire and Vermont**: Similar to northern Maine, northern New Hampshire and Vermont are areas with relatively high concentrations of wind generation. Additionally, northern Vermont receives the power imported from the Hydro-Québec control area over the Highgate tie line.

3) **New York**: The lines connecting New York and New England frequently reach their limit during periods when there are large price differences between the regions (e.g., some winter months when New England's gas infrastructure can become constrained resulting in higher New England prices) or when there are reductions in the interface limit.

4) **Southwestern Connecticut**: Multiple high capacity and efficient natural gas-fired generators have been added in this region in recent years resulting in increased in-merit supply. At times, the 115-kV system can limit the export of low-cost power out of this region to the rest of the system, especially when nearby transmission lines are taken out of service for repair or upgrade work.

5) **Eastern Rhode Island**: This region near Providence, Rhode Island, experiences periodic congestion on the 115-kV system. At times, this can happen when there are pipeline gas price differences such that more gas-fired generators on the west side of the constraint are committed than on the east side of the constraint. Many of the units on the east side of the constraint get their gas from the G lateral on the Algonquin pipeline system, which is frequently more expensive than the non-G price.

8.2 Financial Transmission Rights

The assessment of financial transmission rights (FTRs) activity and performance is structured as follows: (8.2.1) FTR auction volumes, (8.2.2) FTR funding, and (8.2.3) covers profitability at a market level. Given their outsized impact on FTR market outcomes, special attention is given to FTR paths that source from .I.ROSETON 345 1 (“Roseton”), which is ISO-NE’s external node for trading across the New York - New England (“NYNE”) interface.[288]

Key Takeaways

Volumes in FTR auctions increased by 14%, from 29,847 MW per hour in 2022 to 33,881 MW per hour in 2023, marking the highest level over the reporting period. FTRs were fully funded in 2023, meaning there was sufficient revenue collected through the energy markets’ congestion revenue fund to pay FTR holders.

After a modestly profitable year in 2022 ($0.6 million), FTR holders made a collective loss of $14.1 million in 2023. FTR activity associated with the NYNE interface was one reason for this decreased profitability, as the market over-valued associated paths in auctions compared to the day-ahead value of congestion. Losses for FTRs sourcing from this interface increased by $4.2 million between 2022 ($6.8 million) and 2023 ($11.0 million).

8.2.1 FTR Volume

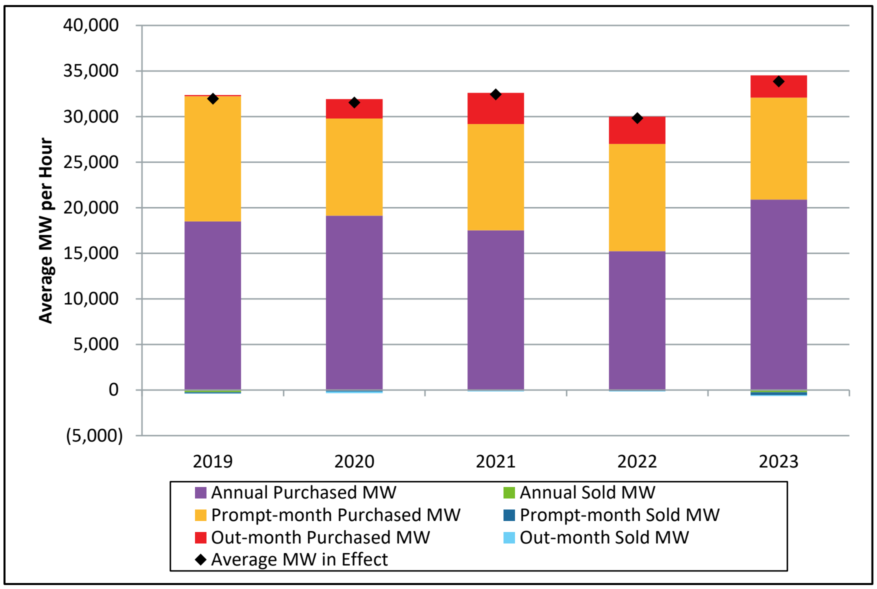
The volume of FTRs that participants hold depends on a number of factors, including participants’ expectations of congestion in the day-ahead market. If participants expect more congestion in the day-ahead market than in prior years, they may purchase more MWs of FTRs to hedge against this expected congestion. Conversely, if participants expect less congestion in the day-ahead market, they may purchase fewer MWs of FTRs. Another important factor is the set of transmission limits that the ISO uses in the auctions it conducts to award FTRs. The ISO performs a market feasibility test in each FTR auction that ensures that the awarded set of FTRs

[288] I.ROSETON 345 1 is represented by area 3 in Figure 8-2 above.

respects the transmission system's physical and operational limits.[289] Essentially, these limits restrict the MW volume of FTRs that can be purchased in FTR auctions, which helps ensure that there will be sufficient congestion revenue from the energy market to pay FTR holders.

Participants held more FTRs (by MWs) per hour, on average, in 2023 than in any other year over the reporting period. This observation can be seen in Figure 8-3, which shows the average MW volume of FTRs that were in effect each hour by year (black diamonds) for the past five years.[290] This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type (i.e., annual, prompt-month, or out-month) during each year.[291] FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

Figure 8-3: Average FTR MWs in Effect per Hour by Year



Market participants held an average of 33,881 MWs of FTRs per hour in 2023, representing a 14% increase from the average amount of FTRs in effect in 2022 (29,847 MWs per hour).[292] This was the result of increased purchases in the annual auctions; these purchases in 2023 (20,884 MWs per hour) were up 37% compared to 2022 (15,241 MWs per hour). Average prompt-month FTR purchases decreased by 5% in 2023 (11,201 MWs per hour) compared to

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[289] This test is performed in order to increase the likelihood of revenue adequacy, which means that there is sufficient congestion revenue collected in the energy market and from FTR holders with negative target allocations to fully compensate all FTR holders with positive target allocations. This is further discussed in Section 8.2.2.

[290] The averages are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

[291] An *annual* auction refers to an auction where participants purchase (or sell) FTRs whose term is one calendar year, while both *prompt-month* and *out-month* auctions refer to auctions where participants purchase (or sell) FTRs whose term is one month. P*rompt-month* refers to the monthly auctions for FTRs that are in effect for the month immediately after when the auction takes place, while *out-month* refers the monthly auctions for FTRs that are in effect for any other month remaining in the calendar year (excluding the prompt month). *Out-month* auctions did not exist until the Balance of Planning Period ("BoPP") project was implemented in September 2019.

[292] One of the primary reasons for this year-over-year increase was that one participant increased their FTR holdings by close to 3,000 MWs per hour between 2022 and 2023.

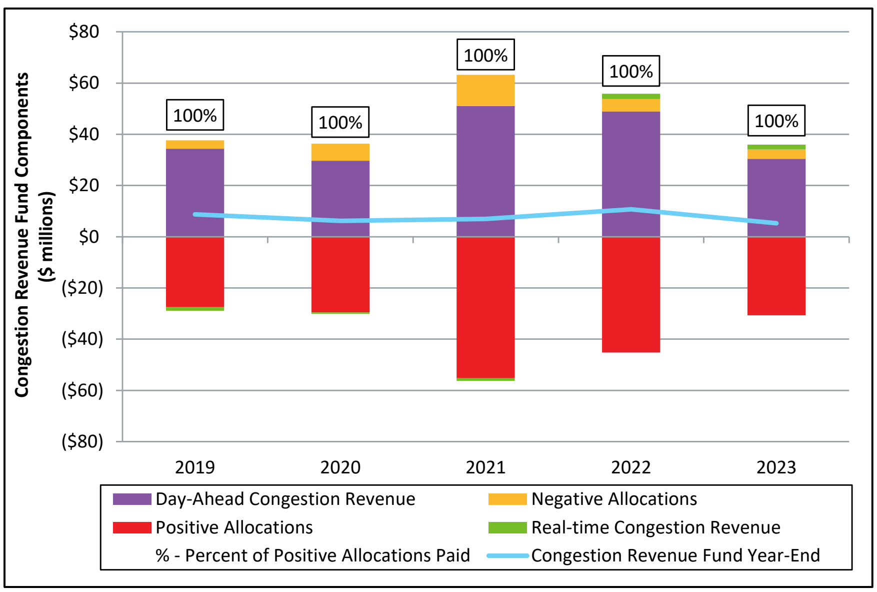
2022 (11,773 MWs per hour), while average out-month FTR purchases decreased by 18% in 2023 (2,456 MWs per hour) compared to 2022 (2,987 MWs per hour). In general, FTR holders sell very few FTRs each year (just 660 MWs per hour on average in 2023), as can be seen below the horizontal axis in Figure 8-3.

8.2.2 FTR Funding

FTR funding refers to the ability to pay FTR holders the full value of their positive target allocations. Positive target allocations arise when the congestion component at the sink location (point of delivery) of an FTR path is larger than the congestion component at the source location (point of injection). When there is sufficient revenue to pay all the positive target allocations, FTRs are said to be *fully funded*. Fully funding FTRs is an important aspect of a well-functioning FTR market because it gives market participants confidence that they will receive the full value of their FTRs.

FTRs were fully funded in 2023 and have been in each of the last five years, as can be seen in Figure 8-4 below. The graph shows, by year, the different components of the congestion revenue fund ("CRF"), including: congestion revenue from the day-ahead and real-time energy markets and positive and negative target allocations.[293] The balance in the CRF at the end of each year is shown by the blue line.[294]

Figure 8-4: FTR Funding and Congestion Revenue Fund Components by Year



[293] The CRF is used to pay FTR holders with positive target allocations. This fund collects money from three sources: (1) day-ahead congestion revenue, (2) real-time congestion revenue, and (3) the holders of FTRs with negative target allocations. For more information about transmission congestion revenue and FTR funding, see *Section III Market Rule 1 Standard Market Design*, Section III.5, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

[294] The CRF balance is defined here as the ∑[day-ahead congestion revenue + real-time congestion revenue + abs(negative target allocations) – positive target allocations].

Positive target allocations in 2023 ($30.7 million) declined by $14.5 million from their 2022 value ($45.2 million). This was consistent with the combination of lower levels of transmission congestion and lower day-ahead energy prices. Day-ahead congestion revenue also decreased in 2023 ($30.4 million) from its 2022 value ($48.9 million), as did real-time congestion revenue, which decreased to $1.9 million in 2023 after reaching $2.1 million in 2022. Negative target allocations in 2023 ($3.7 million) also dropped from their 2022 value ($4.9 million). The CRF year-end balance at the end of 2023 was $5.3 million; this surplus was distributed proportionately to entities that paid congestion costs during the year.[295]

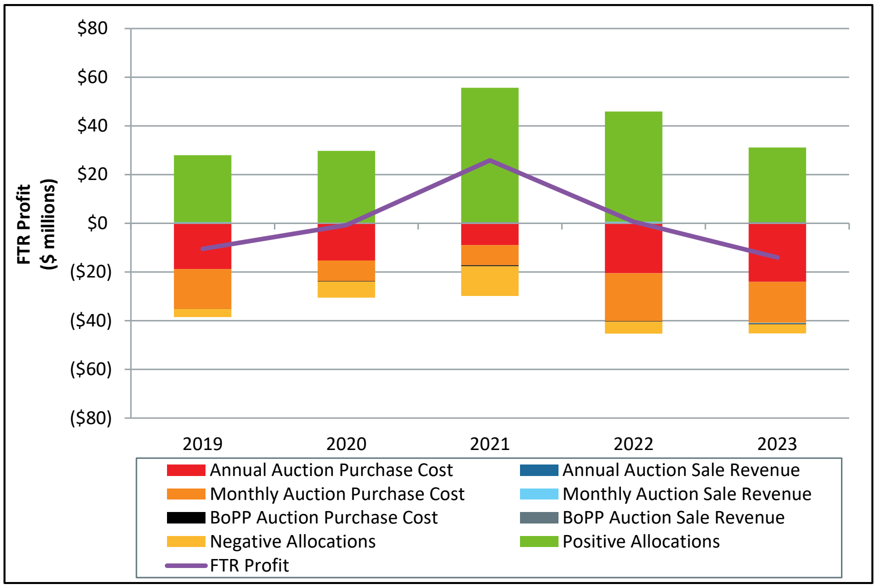
8.2.3 FTR Profitability

Overall profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus the negative target allocations and the cost of FTR purchases. In a competitive FTR market, one would not expect to see excessive (risk-adjusted) profits or losses sustained over numerous years. Prolonged periods of high profitability would likely spur the entry of new participants (or at least an increase in FTR bid prices among existing participants), raising the cost to purchase FTRs and reducing FTR profitability. Conversely, prolonged periods of losses might motivate existing participants to exit the market (or at least decrease their FTR bid prices), lowering the cost to purchase FTRs and increasing FTR profitability.

As a group, FTR holders were unprofitable in 2023. Figure 8-5 below shows total profit (purple line) as well as each of the different profit components. In this figure, FTR sales revenue and positive target allocations are shown as positive values (as they increase FTR profitability), while FTR purchase costs and negative target allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

[295] In 2023, the participants that received this money included generator owners, participants that engaged in virtual and external transactions, and load-serving entities, among others. For more information about the distribution of excess congestion revenue see *Section III Market Rule 1 Standard Market Design*, Section III.5.2.6, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Figure 8-5: FTR Costs, Revenues, and Profits



In 2023, total FTR losses amounted to $14.1 million. This represents a substantial change from the prior two years when FTRs were profitable. Despite the losses as a group, certain FTR holders were profitable individually. Collectively, a decrease in positive target allocations was one of the primary drivers of reduced profits. Positive target allocations totaled $30.7 million in 2023, which was 32% less than their value in 2022 ($45.2 million). At the same time, participants spent more to acquire their FTRs in 2023 ($41.2 million) than they did in 2022 ($40.4 million).

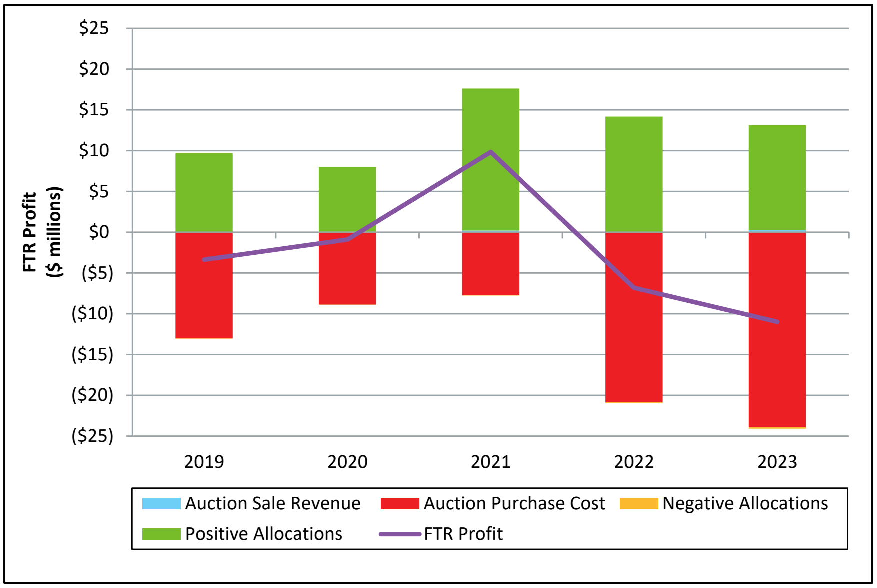
Congestion on the New York – New England Interface

Changes in profitability of FTRs that source from Roseton can contribute significantly to overall FTR market outcomes. This is because the NYNE interface tends to be one of the most frequently binding transmission constraints in the day-ahead market.[296] Typically, participants purchase FTRs that source from Roseton and sink somewhere within the ISO-NE system, as Roseton tends to experience negative congestion pricing in the day-ahead market. To provide some perspective, the purchase costs for FTRs sourcing from Roseton represented 58% of all the FTR auction purchase costs in 2023, while the positive target allocations for FTRs sourcing from Roseton represented 42% of all positive target allocations.

FTRs sourcing from Roseton were unprofitable in 2023. This can be seen in Figure 8-6 below, which shows the total annual profits (purple line) for these FTRs over the last five years. This figure also shows the associated purchase costs, sale revenues, and positive and negative target allocations.

[296] See Section 8.1 for more information about the most frequently binding constraints in 2023.

Figure 8-6: FTR Profits and Costs for FTRs Sourcing from Roseton



The losses associated with FTRs that source from Roseton grew between 2022 (-$6.8 million) and 2023 (-$11.0 million). This decrease in profitability was largely the result of an increase in purchase costs associated with this group of FTRs; participants paid $3.1 million more to acquire FTRs sourcing from Roseton in 2023 ($23.9 million) than they did in 2022 ($20.9 million). At the same time, the holders of these FTRs received $1.3 million less in positive target allocations in 2023 ($12.9 million) than they did in 2022 ($14.2 million). Although the NYNE constraint bound more frequently in the day-ahead market in 2023 (7.5% of hours) than in 2022 (5.9%), the average marginal value of the constraint when it bound in 2023 ($14.27/MWh) was lower than the value in 2022 ($24.22/MWh) due, in part, to lower energy prices. This resulted in lower congestion-related totals at this interface.

Section 9
Market Design or Rule Changes

This section provides an overview of the major market design and rule changes that were recently implemented or are being considered or planned for future years. The section also summarizes notable long-term studies that will have market and operational implications for the future grid. Table 9-1 below lists the design changes summarized in this section.[297]

Table 9-1: Market Design or Rule Changes

Major Design or Rule Changes Recently Implemented	Major Design or Rule Changes in Development or Implementation for Future Years
Inventoried Energy Program	FERC Order 2222, Distributed Energy Resources
Incorporate Solar into Do-Not-Exceed Dispatch	Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)
FCA 19 Delay	Resource Capacity Accreditation (RCA) in the Forward Capacity Market
Revisions to Address Upward Mitigation in the Energy Market	Day-Ahead Ancillary Services Initiative

9.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

9.1.1 Inventoried Energy Program

Implemented for Winters 2023/24 and 2024/25

The Inventoried Energy Program (IEP) provides an interim solution to compensate and incent inventoried energy during the winter seasons of 2023/24 and 2024/25. The IEP allows resources to sell inventoried energy that may provide reliability value to the region during certain trigger conditions.[298] Participating resources can sell this inventoried energy at either a forward settlement rate for the winter season or a spot rate. If a resource sells inventoried energy forward, it is paid (charged) the spot rate for any difference between its actual inventoried energy during each trigger condition and its forward position.

In 2022, following a FERC order that was in response to a decision from the U.S. Court of Appeals for the D.C. Circuit, the ISO made a compliance filing to make nuclear, coal, biomass,

[297] See an overview of ISO's *Key Projects*, available at https://www.iso-ne.com/committees/key-projects

[298] A trigger condition occurs when the average of the daily high and low temperature measured at Bradley International Airport in Windsor Locks, Connecticut, is 17°F or lower.

and hydroelectric generators ineligible for the program.[299] In 2023, the ISO filed further proposed changes to the IEP program that include an update to the settlement rate calculation to better reflect evolving global LNG market conditions, and to allow pumped-storage electric storage facilities to participate in the program.

The first date for which IEP was in effect was December 1, 2023.

9.1.2 Incorporate Solar into Do-Not-Exceed Dispatch

Implemented for December 5, 2023

In November 2022, the ISO submitted to FERC proposed tariff changes to incorporate front-of-meter solar resources into the Do-Not-Exceed (DNE) dispatch rules. Existing DNE dispatch rules allow for inclusion of certain intermittent resources—wind and run-of-river hydro generators—into the ISO's real-time economic dispatch and avoids the need for manual dispatch of these resources. With DNE dispatch, the ISO sends to each DNE resource, a DNE dispatch point, which is the maximum output level that the generator must not exceed.

In January 2023, FERC issued a letter order accepting the ISO's proposal to incorporate solar into DNE dispatch with an effective date of December 5, 2023.[300] As of this effective date, the existing DNE rules for wind and run-of-river hydro were extended to front-of-meter solar resources.

9.1.3 FCA 19 Delay

In November 2023, the ISO proposed to delay FCA19 by one year. In April 2024, the ISO proposed to further delay FCA19. Under this proposal, FCA19 will be run in February 2028. The purpose of this delay is to allow additional time to work through details of the Resource Capacity Accreditation project as well as a prompt/seasonal market design[301], which are planned to be implemented with FCA19.

FERC accepted the ISO's proposal in May 2024.[302]

[299] In December 2022, the ISO and NEPOOL also jointly filed tariff changes related to incorporating financial assurance and billing policy changes related to the IEP, which were accepted by FERC in early 2023. See FERC, letter order accepting ISO New England Inc.'s *12/22/2022 filing of revisions to its Transmission, Markets, and Services Tariff to revise the Financial Assurance Policy etc. under ER23-705, Docket No. ER23-705-000* (February 14, 2023), https://www.iso-ne.com/static-assets/documents/2023/02/er23-705-000.pdf https://www.iso-ne.com/static-assets/documents/2022/02/er22-733-000_2_25_22_order_accepting_transmission_planning_improvements.pdf

[300] FERC, Letter order accepting ISO New England Inc.'s *November 30, 2022 filing of revisions to section III.1.11.3(e) of Market Rule 1 of its Transmission, Markets and Services Tariff etc. under ER23-517., Docket No. ER23-517-000* (January 19, 2023), https://www.iso-ne.com/static-assets/documents/2023/01/er23-517-000_1-19-23_ltr_order_accept_incorporate_solar_sources_dne.pdf https://www.iso-ne.com/static-assets/documents/2022/02/er22-733-000_2_25_22_order_accepting_transmission_planning_improvements.pdf

[301] See section 9.2.3

[302] See FERC's letter accepting the ISO's filing *Docket No. ER24-1710-000* (May 20, 2024), available at https://www.iso-ne.com/static-assets/documents/100011/er24-1710-000.pdf

9.1.4 Revisions to Address Upward Mitigation in the Energy Market

In May 2023, FERC issued an order granting cost recovery to a Market Participant that was subject to upward mitigation of its energy market supply offers, and established a Show Cause proceeding directing the ISO to examine its mitigation rules and propose tariff changes to address the concerns expressed by the Commission relating to upward mitigation.[303]

In November 2023, the ISO filed a set of tariff changes that prevent an outcome in which energy market supply offers are mitigated to reference levels that are higher than the resource's submitted offer.[304] This filing was accepted by FERC, and the changes were implemented on December 12, 2023.

9.2 Major Design or Rule Changes in Development or Implementation for Future Years

The following market design or rule changes are either (i) currently being assessed or are in the design phase or (ii) have been completed and the planned implementation date is in the future.

9.2.1 FERC Order 2222, Distributed Energy Resources

FERC issued orders in 2023 on the ISO's compliance filings, establishing further compliance

On September 17, 2020, FERC issued Order 2222, which found that existing ISO/RTO market rules were unjust and unreasonable because they contained barriers to the participation of distributed energy resources aggregations (DERAs).[305] The purpose of Order 2222 is to remove these barriers and allow DERAs to provide all services that they are technically capable of providing. Specifically, the order outlined 11 directives for ISOs/RTOs to follow, including allowing participation of DERAs in the energy, ancillary services, and capacity markets, allowing DER aggregators to register DERAs under one or more participation models[306], and establishing a minimum size requirement for DERAs of no more than 100 kW.

During 2020 and 2021, the ISO worked with stakeholders to develop the tariff revisions necessary to come into compliance with Order 2222. The ISO's proposed tariff changes were

[303] See *Order Granting Cost Recovery Request in Part and Denying in Part and Establishing a Show Cause Proceeding* (Issued May 5, 2023), ISO-NE Docket No. Docket No. EL23-62-000, available at https://www.iso-ne.com/static-assets/documents/2023/06/el23-62-000.pdf

[304] See *Revisions to ISO New England Transmission, Markets and Services Tariff to Eliminate Energy Supply Offer Upward Mitigation, Docket No. ER24- -000* (November 2, 2023), available at https://www.iso-ne.com/static-assets/documents/100005/elim_energy_supply_offer_upward_mitigation.pdf

[305] DERAs are aggregations of small-scale power generation or storage technologies, such as electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their charging equipment. See FERC's *FERC Order No. 2222: Fact Sheet* webpage (last updated September 28, 2020), https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

[306] A "participation model" refers to rules created for a specific type of resource that has unique physical and operational characteristics. For example, a generator is a type of participation model in ISO-NE. See *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets; Docket No. ER22-___-000* (September 17, 2020), p. 5, footnote 7, available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf

brought through the complete stakeholder process. At its January 2022 meeting, the NEPOOL Participant's Committee voted to support the proposal (71.10% in favor).

On February 2, 2022, the ISO, joined by NEPOOL and the PTO AC, filed a compliance proposal for Order 2222.[307] The proposal creates two new participation models for the energy and ancillary services market (called Demand Response DERA and Settlement Only DERA) and leverages five existing models to accommodate the physical and operational characteristics of DERAs. The proposal includes many other changes to comply with the order, including introducing a new participation model for the FCM (called a Distributed Energy Capacity Resource), setting a minimum size of 100 kW for DERAs, specifying locational requirements, and establishing metering and telemetry rules.

The ISO requested two effective dates: 1) November 1, 2022 for FCM-related revisions, which would be in time for the FCA 18 qualification process, and 2) November 1, 2026 for changes related to the energy and ancillary services market.

In March 2023, FERC issued an order accepting in part and rejecting in part the ISO's compliance filing, subject to further compliance filings. In its order, the FERC found that the ISO's compliance filing satisfied six of the eleven aforementioned directives in Order 2222 but only partially satisfied the remaining five directives, which include issues related to storage participation models, information and data requirements, metering and telemetry requirements, and other issues.[308] FERC established 30-day, 60-day, and 180-day compliance filing requirements for addressing these deficiencies.

The ISO submitted filings in March 2023,[309] May 2023,[310] and August 2023[311] provide additional information needed by FERC in its March 2023 order. In October 2023, FERC issued an order accepting the ISO's 30-day and 180-day compliance filings, and established a new effective date of March 1, 2024, for rules allowing DECRs to participate in the FCM.[312] On November 2, 2023, FERC issued an order accepting the ISO's 60-day compliance filing on all but one of the

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[307] See *ISO New England Inc., Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets, FERC filing, Docket No. ER22-983-000 (February 2, 2022)*,available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf

[308] For a summary of the FERC's order on compliance filing, see memorandum *Overview of the FERC's Order on New England's 2/2/22 Order 2222 Compliance Filing* (March 3, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/03/a05_2023_03_07-09_order_2222_nepool_counsel_memo.pdf.

[309] See *ISO New England Inc., Thirty-Day Informational and Compliance Filing Regarding Order No. 2222 Compliance, Docket No. ER22-983-*____ (March 31, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/03/er22-983_iso-ne_30-day_comp_filing.pdf

[310] See *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff In Further Compliance with Order No. 2222 and Request for Extension of Compliance Deadline; ISO New England Inc., Docket No. ER22- 983-*____ (May 9, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/05/er22-983-further_order_no_2222_compliance.pdf

[311] See *ISO New England Inc., One Hundred Eighty-Day Informational and Compliance Filing Regarding Order No. 2222 Compliance, Docket No. ER22-983-*____ (August 28, 2023), available at https://www.iso-ne.com/static-assets/documents/2023/08/order_2222_compliance_filing.pdf

[312] See FERC's *Order Accepting Order No. 2222 Informational Filing and 180 Day Compliance Filing*, Docket No. ER-ER22-984-005 (October 25, 2003), available at https://www.iso-ne.com/static-assets/documents/100004/er22-984-005_and_003.pdf

compliance items.[313] FERC established a compliance deadline of January 31, 2024, for the ISO to file changes to allow the DER Aggregator to be the entity responsible for providing any required metering information.

9.2.2 Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)

FERC accepted MOPR elimination filing in 2022

In May 2022, FERC accepted the ISO's and NEPOOL's joint proposed tariff revisions to remove the MOPR.[314] These approved changes eliminate the core components of the MOPR (i.e., offer review trigger prices) as well as the substitution auction effective for Forward Capacity Auction (FCA) 19 (capacity commitment period June 2028–May 2029). There is a two-year transition period (FCAs 17 and 18) where the MOPR remains in effect; during the transition period, the Renewable Technology Resource (RTR) exemption has been reinstated, which may allow a greater number of sponsored policy resources to sell capacity.[315]

Beginning in FCA 19, the MOPR will be replaced with a revised buyer-side market power framework. Under this new approach, resources that fall into certain categories are not subject to buyer-side market power review; these include resources with capacity of 5 MW or less, passive demand-response resources, those with no load-side interest (i.e., "competitive entrants"), and certain federally or state-sponsored resources. Resources that do not fall into any of these categories will be subject to a buyer-side market power review by the IMM.[316]

9.2.3 Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)

ISO currently reviewing the projected filing date to FERC

In 2022, the ISO began the stakeholder process for the resource capacity accreditation (RCA) project. This initiative aims to assess and implement methodologies of accrediting resources in the FCM that will better reflect their contributions to resource adequacy. Under the proposed RCA reforms, the ISO would accredit resources based on their Marginal Reliability Impact (MRI), which reflects each resource's incremental contribution to resource adequacy. As part of this effort, the ISO is also pursuing changes to improve accreditation during winter by modeling gas limitations and accounting for fuel storage capability and contracting arrangements when accrediting gas-fired resources.

RCA stakeholder discussions continued throughout 2023.

[313] See *Order on Compliance Filing Docket No. ER22-983-004* (November 2, 2023), available at https://www.iso-ne.com/static-assets/documents/100005/er22-983-004.pdf

[314] See FERC's *Order Accepting Tariff Revisions Docket No. ER22-1528-000* (May 27, 2022), available at https://www.iso-ne.com/static-assets/documents/2022/05/er22-1528-000_5-27-2022_order_accept_mopr_removal.pdf

[315] The RTR exemption would be 300 MW in FCA 17 and 400 MWs in FCA 18 (less substitution auction MWs in FCA 17). During the transition period, the substitution auction test price would also be eliminated.

[316] This review consists of a conduct test, wherein a resource fails the conduct test if its requested offer is below the resource's offer floor price. Those that fail the conduct test have the opportunity to avoid mitigation if they can sufficiently demonstrate that they would be unlikely to realize a material, net financial benefit from lowering FCA prices.

9.2.4 Day-Ahead Ancillary Services Initiative

FERC accepts March 2025 implementation

The Day-Ahead Ancillary Services Initiative (DASI) sets out to procure and transparently price specific ancillary services needed for system reliability. Currently, there is no day-ahead reserves market in ISO-NE. The ISO proposes to create four new reserve products that would be co-optimized with energy and priced in the day-ahead market.[317] These day-ahead reserve products are not forward sales of reserves that settle against real-time reserve prices; instead, they have an energy call-option settlement structure, where the Day-Ahead Ancillary Services are settled like a call option based on a pre-determined strike price and the actual real-time Hub LMP. The ISO also proposes to retire the Forward Reserve Market at the time of DASI implementation.

The ISO submitted proposed tariff revisions for DASI to FERC in October 2023, and FERC accepted those revisions, establishing an effective date of March 1, 2025.

9.3 Additional Notable Studies

The following subsection provides an overview of additional notable studies that are not part of any planned market design or implementation work.

9.3.1 Operational Impact of Extreme Weather Events

Throughout 2023, the ISO worked in collaboration with the Electric Power Research Institute (EPRI) and market participants to conduct a forward-looking probabilistic energy adequacy study for the New England region under extreme weather events.[318] The objective of this study was to inform stakeholders on regional energy shortfall risk over a five to ten year time horizon, and the results are intended to help to quantify a regional energy shortfall threshold. The study was performed using the Probabilistic Energy Adequacy Tool (PEAT), and examined energy shortfalls under selected extreme weather scenarios for winter and summer of 2027 and 2032. This tool produces a range of energy shortfall quantities for each scenario, as well as the associated probability of each energy shortfall within each scenario. The ISO considered a variety of assumptions in the study, including that the market will respond with new resources to meet increased electrification load and replace retiring resources, that there will be a reliable gas system and responsive oil supply chain, that transmission will be built to interconnect wind and import Canadian hydropower, and that there will be few energy limitations due to emissions restrictions. In addition, the ISO studied a wide variety of participant-suggested scenarios.

This study had many key takeaways. Energy shortfall risk was observed to manifest primarily under winter conditions, and the observed shortfall risk appeared manageable over a 21-day period. No energy shortfall risk was observed for summer extreme weather events. In addition,

[317] Three of these products mirror the three real-time reserve products: TMSR, TMNSR, and TMOR; the fourth product is called Energy Imbalance Reserve, which is procured to essentially help fill any potential "energy gap" between forecasted load and cleared day-ahead physical supply.

[318] For the final report discussed with the Reliability committee in November 2023, see *Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results*, available at https://www.iso-ne.com/static-assets/documents/100006/operational_impact_of_exteme_weather_events_final_report.pdf

energy shortfall risk was observed to be similar in scenarios with and without the Everett Marine Terminal in service. The PEAT framework is expected to serve as a foundation for continued study of energy shortfall risk as the power system evolves.

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
BTM	behind-the-meter
Btu	British thermal unit
C4	market concentration of the four largest competitors
CASPR	Competitive Auctions with Sponsored Policy Resources
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation
DARD	dispatchable asset related demand
DDBT	dynamic de-list bid threshold

Acronyms and Abbreviations	Description
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EGEL	Electricity Generator Emissions Limits (program)
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GW	gigawatt
GW-month	gigawatt-month
GWh	gigawatt-hour
GWSA	Global Warming Solutions Act
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor

Acronyms and Abbreviations	Description
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOC	lost opportunity cost
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone

Acronyms and Abbreviations	Description
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PPR	pay-for-performance penalty rate
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PTO	Participating Transmission Owners
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter
RA	reconfiguration auction
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative

Acronyms and Abbreviations	Description
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
UTC	up-to-congestion
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate