2024 State of the Market Report for the New York ISO Markets

POTOMAC ECONOMICS

By:
David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.
Joseph Coscia

Market Monitoring Unit
for the New York ISO

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Guide to Acronyms

BPCG	Bid Production Cost Guarantee
CAF	Capacity Accreditation Factor
CARC	Capacity Accreditation Resource Class
CLCPA	Climate Leadership and Community Protection Act
CONE	Cost of New Entry
CP	PJM's Capacity Performance rule
CRI	Cost of Reliability Improvement
CRIS	Capacity Resource Interconnect. Service
CRM	Constraint Reliability Margin
CTS	Coordinated Transaction Scheduling
DEC	Department of Environmental Conservation
DPS	Department of Public Service
DMNC	Demonstrated Maximum Net Capability
FERC	Federal Energy Regulatory Commission
GFC	Going Forward Cost
GTDC	Graduated Transmission Demand Curve
ICAP	Installed Capacity
IPR	Intermittent Power Resource
IRM	Installed Capacity Margin
ITC	Federal Investment Tax Credit
kV	Kilo-volt
LBMP	Location-Based Marginal Price
LCR	Locational Capacity Requirement
LIPA	Long Island Power Authority
LOLE	Loss of Load Expectation
MMbtu	Millions of British Thermal Units
MW	Megawatts
MWh	Megawatt-hours
NYSERDA	NYS Energy Research & Development Authority
NYSRC	NYS Reliability Council
NYTO	New York Transmission Owner
OOM	Out-of-merit or Out-of-market
ORDC	Operating Reserve Demand Curve
MRI	Marginal Reliability Impact
PFP	ISO-NE's Pay for Performance rule
PPTN	Public Policy Transmission Need
PSC	NYS Public Service Commission
PTC	Federal Production Tax Credit
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RTC	Real-Time Commitment model
RTD	Real-Time Dispatch model
SCR	Special Case Resource
SDU	System Deliverability Upgrade
TCC	Transmission Congestion Contract
TSL	Transmission Security Limit
TVR	Transient Voltage Recovery
UCAP	Unforced Capacity
UOL	Upper Operating Limit
VFT	Variable Frequency Transformer

EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit (MMU), we evaluate the competitive performance of NYISO's wholesale electricity markets, identify market flaws, and recommend improvements to the market design. We also evaluate the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. This State of the Market Report presents this evaluation for 2024.

NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of resources to meet the system's demands at the lowest cost. These markets also provide competitive incentives for resources to perform reliably in the short term and make efficient investment and retirement decisions in the long term. The energy and ancillary services markets are supplemented by the installed capacity market to satisfy NYISO's planning requirements.

As New York State policy initiatives require the generation fleet to reduce and eventually eliminate carbon dioxide emissions by 2040, the energy, ancillary services, and capacity markets will help channel investment toward projects that enable the NYISO to achieve these goals while maintaining reliability at the lowest possible cost.

Market Highlights in 2024

The NYISO markets performed competitively in 2024 and the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were effective in limiting conduct that would raise energy and capacity prices above competitive levels. Market results and trends are summarized below.

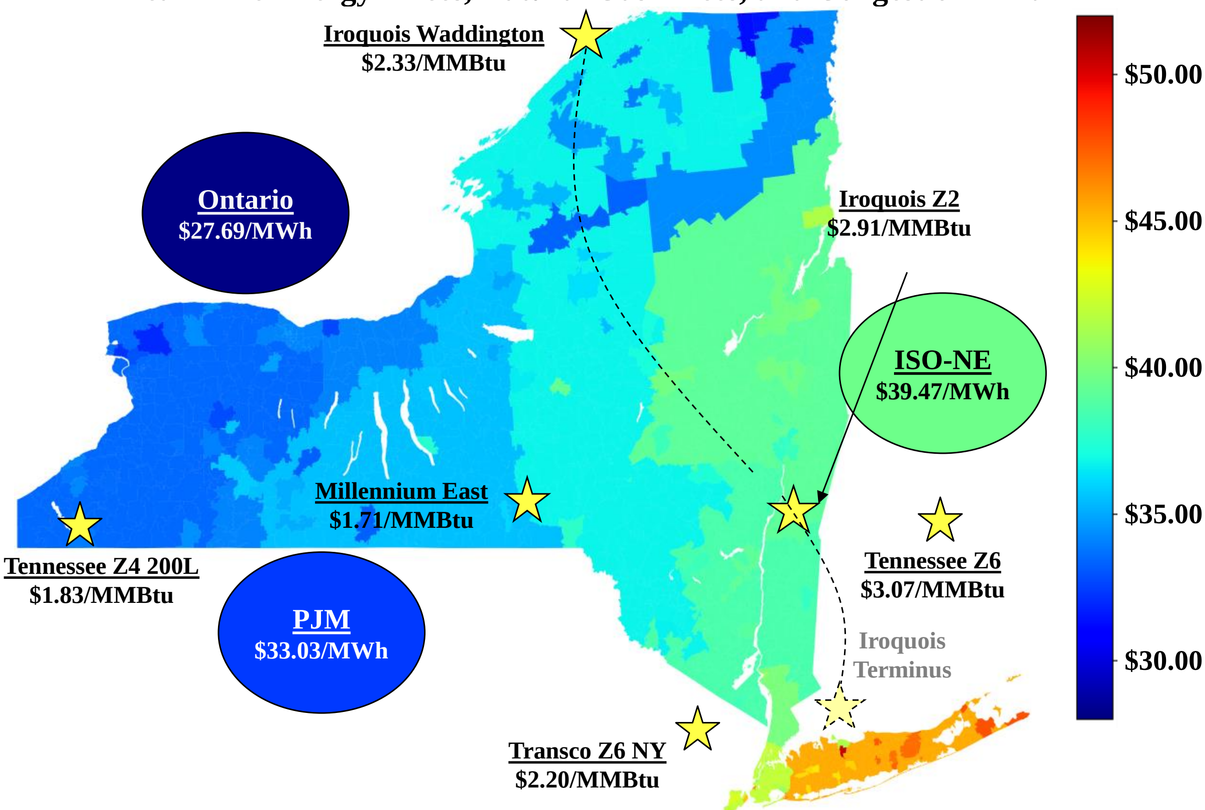
Natural Gas Prices

Electricity prices depend primarily on natural gas prices and load levels. Average gas prices were comparable to the previous year throughout the State. In most western regions, gas prices averaged below $2 per MMBtu in 2024. In eastern New York, however, average prices ranged from $2.19-to-$3.06 per MMBtu with most of the volatility occurring in the winter months of January and December. Mild weather conditions combined with increased domestic production kept gas prices low throughout most of the year. (See Section II.C for details).

Energy Prices and Transmission Congestion

Average energy prices rose from 2023 in Western New York by 27 to 35 percent and in Eastern New York by 6 to 17 percent even though average gas prices were comparable to the previous year. The increase in energy prices occurred primarily due to reduced imports from neighboring regions and higher CO_2 emissions allowance prices. Transmission congestion and losses in 2024 caused real-time prices to vary from $32.50 per MWh in the West Zone to $44.70 in Long Island on average. (See Section II.A)

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2024



Price increases were proportionally largest in western New York because transmission congestion across the Central-East interface fell in 2024 compared to the prior year. This decrease was primarily due to increased transfer capability from newly-built transmission projects, generally mild winter weather conditions, and a significant reduction in net imports from Quebec. Congestion increased in NYC from $15.7 million in 2023 to $52 million in 2024 because of transmission outages. Overall, congestion revenues collected in the day-ahead market fell 2 percent from 2023, totaling $306 million in 2024. (See Section VII.A) The most congested corridors in 2024 included: the Central-East Interface (24 percent of all congestion), NYC 345 kV & Load Pocket Lines (17 percent), Long Island (19 percent of all congestion), external interfaces (16 percent), and West-to-Central (15 percent).

Capacity Market

Capacity prices fell in all regions of the state in 2024. Lower load forecasts (507 MW systemwide) and lower reference prices on the UCAP demand curves were the primary drivers of these lower prices. Local requirements varied with the IRM increasing by 2 percent to 120 percent and the LCR in Long Island increasing slightly by 0.1 percent. The LCRs in G-J Locality and in NYC both fell (4.4 percent and 1.3 percent, respectively). The lower load forecast and LCR also caused G-J prices to never clear above the systemwide price in 2024. Capacity prices fell by 29 percent in NYC despite a reduction in local supply (-218 MW) because of the lower LCR, load forecast, and reference prices.

Statewide prices are more volatile month over month than prices in the localities especially during the winter months. (See Section VIII.A) The highest systemwide Spot Price in 2024 occurred during the winter (January 2024) largely because capacity was exported to Canada during the peak winter months. The fluctuations in net imports from Quebec were the main cause for variations in statewide capacity prices, which ranged from $0.44 per kW-month in April 2024 to $4.58 per kW-month in January 2024. These factors also accounted for capacity price variations in the G-J Locality and Long Island, where spot prices nearly always cleared on the systemwide demand curve in the 2024/25 Capability Year.

Investment Incentives for Public Policy Resources

NYISO's market provides price signals that motivate firms to invest in new resources, retire older units, and maintain existing generating units. In recent years, investment has shifted towards clean energy resources in response to State climate law, which requires 70 percent renewable electricity by 2030 and 100 percent zero-emission electricity by 2040. NYISO market revenues play an important role in these investments because they reward the highest-value clean energy projects. Ultimately, this reduces the cost of achieving policy goals. In Section III, we analyze investment incentives for renewable and energy storage resources.

Incentives for Renewable Generation Investment

Development of new renewable generation is lagging State targets. Of 14 GW of land-based wind and solar awarded contracts with NYSERDA under the Clean Energy Standard, just 1.3 GW has been deployed and over 8 GW have canceled their contracts. Similarly, all 8 GW of awarded offshore wind projects have canceled their original contracts. Of these, 2 GW were re-awarded contracts by NYSERDA in February 2024 at higher contract prices. Renewable generation projects have faced a variety of obstacles including major cost increases since 2021, increased market risks, and interconnection and permitting obstacles. (See Section III.B)

To encourage investment when costs are rising, recent solicitations have awarded contracts at higher Index REC strike prices than those awarded before 2023. For solar, land-based wind, and offshore wind projects still under contract, we estimate that total revenues (including federal and State subsidies) are likely sufficient to support investment at the contracted price level. These subsidies are a major component of the investment incentives, providing 48 to 56 percent of revenues for land-based renewables and 59 percent for offshore wind. (See Section III.A)

Large-scale deployment of renewables drives down wholesale prices where the market is saturated with renewables, increasing market risk for renewable developers under the Index REC contract structure. Exposure to market risk encourages developers to pursue the most efficient projects, but it may also require higher strike prices to offset the risk of market saturation.

In high-wind areas, we already observe significant reductions in market revenues for wind generators relative to zonal averages. In recent years, average realized prices for land-based wind units have been lower by about $5 to $15 per MWh than zonal average prices (to which Index REC contract payments are indexed). We estimate that recent Index REC contract strike prices for land-based wind significantly exceed the levelized cost of new entry for wind units, which may reflect developers' expectations that they will under-perform their strike price due to depressed realized prices. This trend is likely to continue as additional renewable projects are contracted with rising REC prices, increasing the financial risks to earlier projects and the likelihood that more contracts will be canceled. (See Section III.B)

Incentives for Energy Storage Investment

Less than 100 MW of energy storage capacity has entered the NYISO markets since the State implemented its storage incentive program in 2018, despite a CLCPA mandate for 3 GW by 2030 and the State target of 6 GW by 2030 announced in 2022. Market revenues have generally been too low to support investment, even with State incentives and the 30 percent federal Investment Tax Credit available as of 2023. (See Section III.A)

The New York Public Service Commission recently approved plans for a new annual solicitation for 1 GW per year of bulk storage for three years, using a new Index Storage Credit contract structure that would provide a partial hedge against NYISO market revenue fluctuations. These developments could accelerate the pace of storage investment in the coming years. However, storage developers will likely require higher contract revenues as State bulk storage procurement plans will reduce anticipated *market* revenues to storage resources from:

- *Energy and reserve sales*: Using our storage revenue estimation model, we find that most revenues would come from selling day-ahead operating reserves. Large-scale entry of bulk storage will likely reduce reserve payments to duration-limited resources. There is some evidence that storage units located near wind generators that experience curtailment would earn higher energy market revenues. But the frequency of renewable curtailment in NYISO is not yet high enough for this to be a major revenue source.
- *Capacity sales*: The Capacity Accreditation Factors (CAFs) of storage should fall as penetration rises because longer durations will be needed to provide comparable reliability. Additionally, the capacity value of storage will fall sharply if future reliability needs are driven by multi-day cold periods in winter because storage contributes little to the total energy supply during these periods. Hence, large-scale storage development will depress their capacity value, increasing their market risk or requiring higher subsidies.

The NYISO markets signal when new storage resources would be beneficial. Storage investment is likely most efficient when it is proportionate to renewable development or in locations where it can help manage congestion caused by fluctuating renewable output. (See Section III.C)

Incentives for Demand-Side Participation in the Wholesale Market

The rate of electricity demand growth is expected to rise because of heating electrification, electric vehicle adoption, and the interconnection of new large loads such as data centers, posing significant challenges for centralized wholesale market operators. NYISO has taken steps to improve demand-side access to the wholesale market, but significant effort is still needed in key areas. NYISO launched its new Distributed Energy Resource (DER) participation model in April 2024, but until [month] 2025, no resource had enrolled to participate in the DER program.

The slow growth in DER program participation is a sign of potential areas for improvement in the DER model. NYISO has sought to transition capacity-selling loads from the legacy emergency demand response ("SCR") program to the new DER participation model, but the current rules impose significant burdens on DERs beyond what is required for generators that sell capacity. DERs can only sell capacity if they are willing to be curtailable with little notice and without the ability to recoup commitment costs with minimum duration or commitment cost bid parameters.

In addition, some new load interconnections do not require firm service because they will be energy-intensive businesses that seek low-cost energy and rapid interconnection but do not have the typical need for reliability or prefer to rely on their own onsite back-up generation. However, NYISO's interconnection process does not have distinct rules for non-firm load customers, and LSEs with curtailable load are allocated the same transmission costs regardless of whether they would contribute to the build-out of the high-voltage transmission system.

These issues will distort incentives for demand-side participation and undermine the benefits to the overall market. Hence, we recommend NYISO evaluate these concerns and consider potential market reforms. (see Section XI and Recommendation 2024-2)

Capacity Market Performance

The capacity market is NYISO's primary means to meet resource adequacy and other planning requirements. It has provided incentives for firms to invest in and maintain needed resources. However, market reforms are needed to ensure the market provides efficient incentives for investment in the locations and types of resources needed for reliability. (see Section VIII)

Defining Granular Pricing Locations

The capacity market's four pricing regions do not adequately capture differences in the reliability value of capacity at different locations. In some areas, capacity is bottlenecked and overvalued because the capacity market does not recognize that it is not fully deliverable (e.g., Staten Island within New York City and the eastern half of Long Island). In other areas, capacity downstream of a major transmission constraint within a region is undervalued (e.g., zones H and I in the Lower Hudson Valley region, which are separated from Zone G by the UPNY-ConEd interface).

These shortcomings lead to over-paying bottled resources in generation pockets and under-paying resources in load pockets, which drives up capacity prices overall and retains excess capacity. This is because the IRM and LCR processes compensate for the presence of bottled capacity in a region by inflating ICAP requirements instead of limiting procurement in the bottled area. This creates inefficient incentives for legacy resources to not retire.

To address this, we recommend that NYISO establish a more disaggregated set of capacity zones and a dynamic process to update them as discussed in Section VIII.C. (Recommendation 2022-4) Because no zone configuration will accurately reflect the key constraints that separate areas from a planning perspective, the recommendation also includes a proposed capacity constraint pricing (CCP) component that would be applied in the capacity settlement. This is an incremental locational price adder that would ensure that the economic signals for each resource reflect its effects on the key planning constraints. The primary effects of the recommendation would be to:

- Discount capacity payments in export-constrained areas that are currently over-priced (e.g., Staten Island) and facilitate retirement of non-deliverable capacity;
- Allow for reliability needs to be efficiently reflected in prices when they emerge;
- Lower costs as LCRs will no longer be inflated to compensate for bottled capacity; and
- Attract and retain capacity in locations where it is most valuable to the system.

Efficient Compensation When LCRs Are Set by Transmission Security Limits

In recent years, the LCRs have increasingly been set based on Transmission Security Limits (TSLs), which are established using a deterministic framework designed to protect against the largest two contingencies. By contrast, the IRM/LCR study employs a probabilistic resource adequacy criteria. The TSLs use assumptions that have become more conservative in recent years, causing the TSL floors to set the LCRs more frequently. The New York City TSL floor is expected to increase further in the coming years, driving up the LCR and prices. In Section VIII.E, we discuss the inefficiencies that occur when LCRs are set based on TSLs:

- *Overcompensation of some resource types*: Some resources provide less transmission security value in the studies than their capacity accreditation. These include demand response (SCRs), intermittent renewables, and large resources whose size increases the TSL contingency. The presence of these resources causes the TSL-based LCRs to increase. Hence, these resources are overcompensated because they are able to sell capacity in the market to satisfy these LCRs. In the 2024/25 Capability Year in New York City alone, we estimate they were over-compensated by up to $46 million.

- *Overcompensation of surplus capacity*: The capacity demand curves are designed to allow prices to fall as the amount of surplus capacity rises above the LCR. When the LCR is set based on the TSL floor, we find that surplus capacity provides less reliability benefit than the current demand curves imply. In other words, it is inappropriate to apply the same demand curve slope when the demand curve is anchored by the TSL floor.

To address these issues, we make two recommendations: (1) Pay resources for capacity according to the requirements which they contribute to meeting (Recommendation 2022-1); and (2) Develop sloped demand curves reflecting the marginal value of surplus capacity for use when an LCR is determined by a TSL (Recommendation 2023-4).

Improvements Needed to Accreditation Models and Inputs

In May 2024, NYISO adopted a new approach for compensating resources based on marginal reliability value. Each class of resources is compensated based on its Capacity Accreditation Factor (CAF), which is set based on the value of the resource for avoiding load shedding using NYISO's resource adequacy model. NYISO and the New York State Reliability Council (NYSRC) evaluate potential improvements to the resource adequacy model each year. Section VIII.D discusses recommended improvements to the resource adequacy models that are needed to accurately assess the value of resources with winter fuel limitations, energy storage, resources whose output is correlated with load, and inflexible resources. (Recommendation 2021-4)

NYISO and NYSRC appear likely to model distinctions between firm and non-firm fuel units in peak winter conditions beginning with the 2026/27 Capability Year. This would greatly improve incentives for resources to be available during peak winter conditions. However, further improvement is needed to appropriately consider contributions to winter energy adequacy (the ability of the system to reliably serve load over a prolonged period such as days or weeks) in the accreditation of other types of suppliers such as battery storage and intermittent renewables.

NYISO's rules overestimate the capacity of many nuclear and fossil-fuel generators because they allow their installed capability to include: "emergency capacity" that is never committed in practice; resources dependent on ambient water temperatures, humidity, or barometric pressure; and cogeneration units that face limitations associated with their steam host demand. We estimate that up to 1.5 GW of this capacity was unavailable on peak days in Summer 2024. (see Section VIII.D). NYISO has begun to address these concerns by proposing new rules for the 2025/26 Capability Year that: (a) place stronger offer obligations on most emergency capacity, (b) narrowing the summer DMNC testing window for units affected by ambient water temperatures, and (c) requiring units to adjust DMNC test results for humidity and pressure as needed.

These efforts should improve the accuracy of DMNC ratings, but nearly 8 GW of fossil-fuel generation in Zones G through K are affected by tidal levels and the effects of barometric pressure changes but this remains unaddressed. We recommend that NYISO continue to pursue efforts to adjust DMNC test results of these units to more accurately determine their capacity under peak conditions.

Seasonal Capacity Market

Resource adequacy risk is growing in winter relative to summer because of the electrification of heating load, winter gas pipeline constraints, retirements of fuel-secure generating capacity, and tightening winter conditions in neighboring regions. NYISO forecasts peak demand in the winter will surpass summer by the late-2030s, and winter reliability risk could surpass summer risk much earlier because of winter fuel supply limitations.

NYISO's capacity market does not consider key factors that lead to seasonal differences in supply and demand. NYISO recently developed improvements that would adjust summer and winter demand curve parameters to account for seasonal reliability risk. However, the capacity market will continue to use a single ICAP requirement for both seasons and CAFs determined annually and applied to all months of the year, which raise the following concerns:

- The capacity market lacks an effective mechanism to coordinate elections of firm fuel supply by generators. Hence, the capacity market will not efficiently attract the levels of firm fuel arrangements needed to manage reliability risk.
- When net capacity imports in winter differ from assumptions in the IRM study, capacity prices and accreditation factors will not be accurate. For example, suppliers may have incentives to export capacity in the winter even when this would heighten reliability risk.
- Annual CAFs for most resources will be volatile because they will be extremely sensitive to assumptions that drive relative seasonal reliability risk in the IRM study.
- Resources with capacity sales that vary between summer and winter (e.g., the 1,250 MW Champlain Hudson Power Express project in New York City) may cause extreme pricing outcomes because this may cause the Winter-Summer Ratio parameter to be inaccurate.

Hence, we recommend establishing seasonal capacity requirements, CAFs, and demand curves (Recommendation 2022-2). This would establish separate capacity requirements in summer and winter so that each season procures sufficient UCAP to satisfy reliability criteria. Each resource's UCAP would be determined using seasonal CAFs reflecting their reliability contributions and would not be sensitive to assumptions regarding relative summer and winter reliability risk. Under this framework, changes in fuel arrangements or net imports would result in appropriate clearing price changes based on the seasonal demand curves.

We also recommend that NYISO make changes to mitigate the risk of extreme pricing outcomes caused by inaccuracies in the Winter-Summer Ratio parameter. (Recommendation 2023-5). While this risk would also be resolved by Recommendation 2022-2, we recommend NYISO expedite addressing this issue because it could cause extreme and inefficient pricing.

Addressing Gaps between the Planning Process and the Capacity Market

Capacity markets should be designed to provide efficient market incentives for attracting and maintaining sufficient resources to satisfy the planning reliability criteria. However, we have found that the reliability planning process effectively requires more capacity to meet transmission security needs than is represented in the capacity market requirements that are explicitly based on transmission security. For example, in our comments on the 2024 Reliability Needs Assessment, we identified that the effective planning requirement for New York City for the 2025/26 capability year was 743 MW higher than the expected capacity market LCR based on the Transmission Security Limit. (see our RNA comments here) While changes in the planning models and methodology may be necessary from time to time, NYISO should seek to minimize inconsistencies between the planning requirements and the capacity market which is ultimately designed to enable NYISO to meet those requirements.

Deliverability Testing and Transmission Planning Processes

The recent influx of proposed new renewable and storage projects in NYISO's interconnection queue has focused attention on transmission planning and interconnection issues. It is efficient for the developer to bear the costs of upgrades needed for a new project to reliably interconnect so they do not disregard potential transmission limitations. At the same time, new projects should not bear a disproportionate share of the cost for upgrades that benefit others because this will deter efficient investment. In Section IV.A, we evaluate the deliverability testing process.

Concerns with the Deliverability Testing Process

The process for obtaining rights to sell capacity ("CRIS rights") can be a major obstacle new generation investment. Recent Class Year studies have identified prohibitively costly System Deliverability Upgrades (SDUs) for many proposed projects, causing them to withdraw from the Class Year or accept a reduced quantity of CRIS rights. For example, 924 MW of battery projects seeking to enter Long Island in the recently completed Class Year 2023 were allocated SDU costs averaging $880 per kW of UCAP and lead times in excess of 8 years, which no developer was willing to accept. Section IV.A highlights that NYISO's deliverability framework is an inefficient barrier to new investment because it:

- Utilizes a deterministic test that often does not represent a realistic or likely dispatch of the system during conditions when reliability is threatened;
- Is particularly likely to identify and allocate excessively large SDUs to renewable and storage project developers as their penetration grows;
- Assigns permanent CRIS rights that may not accurately reflect a resource's deliverability over time or as NYISO shifts from summer-peaking to winter-peaking; and

- Favors existing resources over new resources because it requires developers of new resources to pay for costly network upgrades but imposes no costs on existing resources that contribute to the same bottlenecks. This effectively prevents new resources from competing with incumbent resources in export-constrained areas such as Staten Island.

NYISO's recent transition from the Class Year process to its new Cluster Study interconnection process will improve the overall timeline and information provided to developers, but it retains the existing deliverability test methodology.

To address these issues, we recommend disaggregating NYISO's capacity zones (Recommendation 2022-4). This would reduce the size of the capacity zones in which new interconnecting resources would have to be deliverable and allow capacity prices to drop in export-constrained areas. This would also substantially reduce the number and size of system upgrades developers would be obligated to fund and allow new projects to compete with incumbents. Project developers may still wish to pay for network upgrades when transmission bottlenecks would cause their locational capacity price to be low. Hence, we also recommend financial capacity transfer rights (FCTRs), which could be defined so that market participants who pay for upgrades retain the economic value of those upgrades in the capacity market (Recommendation 2012-1c).

Improvements to Transmission Planning Process

The costs of regulated transmission projects recovered through NYISO rate schedules have risen from approximately $0.50 per MWh of statewide load in 2021 to $2.50 per MWh in 2025 and will continue to rise because of major projects that have been approved or are being evaluated. In Section IV.B, we provide an overview of NYISO's centralized transmission planning process and suggest improvements so more efficient projects are selected. In recent years, large-scale transmission planning has taken place primarily through the Public Policy Transmission Planning Process (PPTPP). Even when transmission projects are planned to meet policy goals, consideration of their market impacts is important because: (1) market prices help quantify which policy projects provide the best value to ratepayers and (2) inefficient transmission projects risk crowding out competing market-based investments (including transmission and non-transmission resources) that could advance the same policy goals at lower cost.

The assumptions and techniques used in NYISO's planning models (particularly the Outlook study) affect which the transmission needs identified, and the solutions selected. NYISO has made improvements to its planning models in recent studies, but we discuss remaining issues in Section IV.B and recommend improvements to address them. (Recommendation 2022-3) Modeling improvements would help to ensure that future transmission needs are assessed accurately and that solicitations select the most efficient candidate projects.

Energy and Ancillary Services Market Performance

We evaluate market performance in scheduling resources efficiently and setting real-time prices, particularly during tight operating conditions. Efficient prices are important because they reward resources for performing flexibly and reliably during tight real-time conditions. This becomes increasingly important as New York integrates more intermittent renewable resources and the supply of fuel-secure generation declines.

Dynamic Reserve Needs

With the addition of intermittent generation, patterns of congestion and operating reserve constraints are becoming more variable. Consequently, NYISO does not always schedule operating reserves efficiently, particularly when local reserve needs could be met more cost-effectively by reducing imports to the local area and increasing internal generation, rather than holding reserves on internal units. Accordingly, we have recommended NYISO dynamically determine the optimal amount of reserves required for both local and systemwide reliability. NYISO is currently working to implement these "Dynamic Reserve" requirements. (Recommendations 2015-16 and 2016-1)

Market Performance under Reserve Shortage Conditions

Shortage pricing will be an essential element of the real-time market as NYISO transitions to a more intermittent generating fleet. Although shortage conditions arise in only a small portion of real-time intervals, their impact on incentives is substantial. Most shortages are transitory as flexible generators respond to rapid or unforeseen changes in load, external interchange, and other system conditions. Since intermittent output fluctuations are expected to grow, shortages are likely to increase. Shortage pricing provides essential incentives for flexible generation to be available and to perform well to maintain reliability.

Shortage pricing levels should be set sufficiently high to avoid relying on out-of-market actions and to accurately reflect the value of reserves for maintaining reliability. In Section VI.A, we identify conditions when the operating reserve demand curves are set below: (a) the cost of out-of-market actions required to maintain reserves when neighboring control areas also experience reserve shortages; and (b) the marginal reliability value of reserves for reducing the risk of load shedding during deep reserve shortages. Hence, we recommend NYISO modify its reserve demand curves to address these issues. (See Section VI.A.1 and Recommendation 2017-2)

Understated shortage pricing is particularly harmful to NYISO because of the extremely aggressive shortage pricing in neighboring markets. Resources selling into the ISO-NE and PJM markets could receive $5,000 to $10,000 per MWh during *slight* shortages of 10-minute and 30-minute reserves, while the NYISO market sets its prices between $750 and $3,000 per MWh during *deep* 10-minute and 30-minute shortages. This misalignment in shortage pricing between

NYISO and its neighbors will potentially cause energy to flow out of New York to neighboring markets even when shortages in NYISO are much deeper. The need to schedule imports and exports efficiently will become increasingly important as the penetration of intermittent resources grows.

Market Performance under Transmission Shortages

Transmission shortages occur when the power flowing over a transmission facility exceeds the applicable operating limit, which can be due to a lack of available resources in NYISO's dispatch model to relieve the constraint or because the market software is designed to allow small constraint violations when the cost of relieving the constraint would otherwise exceed $200 per MWh (which is the first step of the Graduated Transmission Demand Curve (GTDC)). In 2024, the market experienced such localized shortages in roughly 9 percent of real-time intervals.

NYISO implemented *Constraint Specific Transmission Shortage Pricing* in November 2023. This enhancement aligns the MW steps on the GTDC with the Constraint Reliability Margin (CRM) for each facility, improving correspondence between shadow prices and the severity of transmission constraints. Despite this enhancement, the use of "offline GT pricing" continues to undermine pricing efficiency by preventing the market software from recognizing some transmission shortages in real time. This mechanism causes congestion prices to fail to represent the severity of actual transmission shortages. Currently, NYISO's real-time pricing model assumes that offline GTs can respond to dispatch instructions within 5 minutes, even though they are not physically capable of doing so. Consequently, the market model may underestimate the scarcity of transmission capability, leading NYISO to compensate for these differences by over-constraining transmission in some areas that rely heavily on gas turbines. To address this inefficiency, we recommend NYISO eliminate offline fast-start pricing from the real-time dispatch model. (See Section VI.A.2 and Recommendation 2020-2)

Real-time Pricing Efficiency During Gas Turbine Starts

Despite recent improvements to the fast-start pricing logic, we have identified a remaining issue in the real-time pricing algorithm. Specifically, the problem arises when the real-time scheduling software economically commits gas turbines offering minimum run times longer than one hour. Although these units are scheduled as if they have a one-hour minimum run time, the pricing algorithm does not treat them as eligible to set LBMP. As a result, real-time prices may not accurately reflect the costs of maintaining reliability when these gas turbines are started. If these units were allowed to set real-time prices, LBMPs would have increased by an estimated $1 to $6.5 per kW-year across various load pockets in New York City and Long Island. Additionally, prices would have been affected in broader areas as well depending on congestion patterns.

Hence, we recommend that NYISO revise its real-time fast-start pricing criteria to base fast-start pricing eligibility on the minimum run time used for scheduling, rather than the value of the offer parameter. By aligning pricing and scheduling, NYISO can enhance price efficiency and provide more appropriate investment signals for market participants. (See Section VI.B and Recommendation 2023-2)

Incentives for Combined Cycle Units Offering Duct-Firing Capacity

Most combined cycle units in New York have a duct burner, which uses supplementary firing to increase the heat energy in a gas turbine's exhaust, increasing the output of a downstream heat-recovery steam generator. Duct burners account for ~800 MW of capacity in the State. This can be offered into the energy market as a portion of the dispatchable range of the unit, but a large portion of the duct-firing capacity is either: a) not offered, or b) offered but unable to follow 5-minute instructions in the real-time market because its operational characteristics are not properly recognized by the dispatch model. Neither of these outcomes is ideal so we have recommended NYISO consider enhancements for scheduling this capacity that considers the physical limitations of duct burners.

NYISO's proposal to address this issue would require suppliers to designate a unit's output range as duct-firing through an administrative process rather than making it a bid-able parameter like the upper operating limit (UOL). Like the UOL, the duct-firing range will fluctuate with ambient temperature and humidity conditions. Our analysis estimates the magnitude of scheduling errors if duct-firing ranges remain administrative parameters, even if suppliers update them as frequently as twice per week. (See Section VI.C and Recommendation 2020-1)

Compliance with Curtailment Instructions by Intermittent Power Resources (IPRs)

Resources that depend upon wind and solar energy for their fuel are classified as IPRs. These resources are paid for all their output unless they have been instructed by the NYISO to reduce their output via a Wind and Solar Output Limit ("Output Limit"). We analyzed the performance of IPRs when issued an Output Limit and found that, despite strong performance by most resources, a minority of IPRs account for a disproportionately large share of instances of non-compliance with Output Limit instructions. In addition, we have found that poor performance by certain IPRs has been attributable to communication failures on the part of the local transmission owner rather than the IPR. However, we have also found that when an IPR does not comply with a curtailment instruction, the overgeneration charge may be inadequate to ensure the IPR does not benefit financially from poor performance.

Failure for IPRs to follow the NYISO's Output Limit leads to reliability, security, and settlement inefficiencies. Transmission owners may respond to transmission security issues by imposing conservative line ratings if the expected IPR dispatch performance is poor, which is inefficient. In cases when an IPR is persistently non-responsive, the operators are compelled to curtail other IPRs that are responsive, thereby benefiting the non-compliant IPR at the expense of the compliant one. Therefore, we recommended that NYISO revise the tariff to provide IPRs with stronger incentives to comply with Output Limit instructions. (see Section VI.D and Recommendation 2023-3)

Performance of Coordinated Transaction Scheduling (CTS)

CTS enables two neighboring wholesale markets to exchange information about their internal dispatch costs shortly before real-time, assisting market participants in scheduling external transactions more efficiently. We continue to observe superior performance at the New England interface. In 2024, the CTS process at the New England interface continued to outperform the PJM interface, producing greater cost savings. This was largely attributable to the relatively-poor performance by PJM's real-time price forecasting model that is used in the scheduling process and the higher transaction fees imposed on exports from NYISO across the PJM interface. Both issues diminish the profitability of CTS transactions and participation. Market participants exporting to PJM typically require much larger average price spreads (~$8.5 per MWh in 2024) between the two markets to profit from the transactions. As a result, they offer much lower quantities.

It is unlikely that CTS with PJM will function effectively while transaction fees are large relative to the expected value of spreads between markets. Hence, we recommend eliminating or significantly reducing these costs to unlock the full potential of CTS between PJM and NYISO. Improving the utilization of the CTS processes will allow it to deliver increasing levels of benefits as renewable output grows in the future. The CTS processes can help efficiently balance short-term fluctuations in intermittent generation in New York and neighboring systems. (see Section IX.CC and Recommendation 2015-9)

Operations of PAR-Controlled Lines between New York City and Long Island

While most phase angle regulators (PARs) are operated to reduce production costs, several PARs are still managed according to bilateral contract terms, regardless of economic efficiency. The most significant inefficiencies we identified were associated with the two lines that normally transfer up to 300 MW of power from Long Island to New York City in accordance with a wheeling agreement between Consolidated Edison ("ConEd") and Long Island Power Authority ("LIPA"). The operation of these lines in accordance with the wheeling agreement has resulted in *higher* production costs in millions of dollars each year, and *increased* CO_2 and NOx emissions by a significant amount as well.

In 2024, the inefficient use of the 901 and 903 lines was reduced because of lengthy transmission outages, but the ConEd-LIPA wheeling agreement continued to raise production costs and reduce operational efficiency. As offshore wind and other intermittent renewable resources are increasingly integrated into New York City and Long Island, the operational flexibility of these lines will become even more critical if they could be utilized to avoid curtailing renewable generation. This report recommends that NYISO continue to work with the parties to the

ConEd-LIPA wheeling agreement to explore potential changes that would allow the lines to be used more efficiently. (See Appendix Section III.I and Recommendation 2012-8.)

Allocation of Day-Ahead Congestion Residuals

Day-ahead congestion shortfalls and surpluses, known as "residuals", arise when day-ahead network capability differs from the modeled capability in the TCC auctions. Allocating these residuals on a "cost causation" basis is generally beneficial, as it provides efficient financial incentives for Transmission Owners (TOs) to maintain equipment, configure the transmission system to minimize congestion, and schedule outages when least likely to increase congestion.

Currently, most residuals resulting from "Qualifying" changes in modeled transfer capability between TCC auctions and day-ahead markets are allocated to the responsible TOs. However, any remaining shortfalls and surpluses are distributed in proportion to TCC auction revenues received by each TO. In 2024, this method was used to allocate a net surplus of roughly $33 million, although our analysis indicates that most of the surplus stemmed from incremental transfer capability enabled by recent upgrades associated with Segment A and Segment B Public Policy Transmission Projects or the use of transmission facilities between Con Ed and LIPA.

This allocation methodology does not align with cost causation principles, which fails to incentivize TOs to operate their transmission equipment efficiently and encourages overselling the capability of the transmission system in the TCC auctions. Therefore, we recommend NYISO revise the allocation of day-ahead congestion residuals. Instead of allocating these residuals based on TCC revenues, the allocation should be determined by changes in scheduled utilization of the transmission system between the TCC auctions and the day-ahead market. This adjustment would enable transmission owners to recover the value of transmission scheduled in the day-ahead market, even if the capacity was not fully-sold in the TCC auctions. (See Section VII.D and Recommendation 2023-1).

Out-of-Market Actions

Guarantee payments to generators fell by roughly 32 percent from 2023 to $40 million in 2024. The decrease occurred primarily in New York City, where oil-burn requirements for several steam turbine units during two specific gas pipeline outages in 2023 incurred $20 million in BPCG uplift. (See Section VI.F)

New York City

The need to respond to multiple contingencies was the primary driver of supplemental commitments in 2024. More than 60 percent of guarantee payments in New York City were made to units committed for this purpose. Typically, holding reserves in an area is the most cost-effective means to protect against multiple contingencies. Hence, we recommend the

NYISO model local reserve requirements to satisfy these multi-contingency needs, which should provide more efficient price signals for flexible resources in these areas. (See Section VI.E and Recommendation 2024-1)

NYISO plans to develop New York City load pocket reserve requirements after completing the *Dynamic Reserves* project. This will be particularly important after offshore wind is added to New York City because it will allow NYISO to utilize the wind output and other low-cost generation to satisfy local reliability needs as appropriate.

The NYISO currently operates markets for operating reserves up to 30 minutes, but these multi-contingency needs in New York City could be met by resources with response times up to 60 minutes. In the long term, entry of intermittent renewables will lead to large deviations of net load from the forecast over multiple hours. Procuring reserves from resources with longer lead times (e.g., combined cycle units) would allow NYISO to maintain reliability more cost-effectively. Hence, we recommend that NYISO evaluate the need for longer lead time reserve products. (See Recommendation 2021-1)

Long Island

OOM dispatches to manage 69 kV constraints on Long Island have reduced significantly since NYISO began integrating 69 kV constraints into its day-ahead and real-time markets in April 2021, leading to more efficient scheduling and pricing and reduced BPCG uplift. However, OOM commitments of peaking units for Transient Voltage Recovery (TVR) requirements on the East End of Long Island were still frequent, leading to inefficient price signals in that area. To provide more efficient incentives for scheduling and new investment, we recommend NYISO model East End TVR needs (using surrogate constraints) in the market software. (See Section VII.B and Recommendation 2021-3)

In addition, we found that the current Long Island reserve requirement was sometimes inadequate to satisfy multi-contingency criteria. Modeling these reserve requirements in Long Island would improve efficiency and encourage new resources with flexible characteristics to locate where they are most valuable. Hence, we recommend that NYISO implement reserve requirements for Long Island that are adequate to maintain reliability rather than rely on OOM actions. (See Appendix Section III.D and Recommendation 2024-1)

Upstate New York

OOM commitments in upstate regions have increased over the past two years primarily to satisfy the multi-contingency criteria in the North Country load pockets - 143 days in 2023 and 205 days in 2024. We recommend modeling reserve requirements in local load pockets to improve scheduling efficiency and establish more efficient market signals for new investment. (See Section VI.E and Recommendation 2024-1)

Overview of Recommendations

Our analysis in this report indicates that NYISO's electricity markets performed well in 2024, although we recommend additional enhancements to improve market performance. Some of these recommendations address emerging issues that will become increasingly important as the system evolves and the State moves forward with its clean energy policies.

The table below summarizes our high-priority recommendations. The majority of our recommendations were made prior reports, but we make two new recommendations in this report. In general, the recommendations that are designated as "high priority" are those that produce the largest economic efficiencies by lowering production costs of satisfying the system's needs or improving the incentives of participants to make efficient long-term decisions.

A complete list of recommendations and a detailed discussion of each recommendation is provided in Section XI. In total, we have 24 outstanding recommendations that are discussed in that section.

High Priority Recommendations in the 2024 SOM Report

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
Energy Market Enhancements – Pricing and Performance Incentives			
2015-16	2023 SOM Appx. V.N	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	*Dynamic Reserves:* (Software Design Specs / Development Complete)
2016-1	2023 SOM Appx. V.D	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2024-1	VI.E	Use the reserve market rather than out-of-market actions to satisfy local reserve requirements in New York City, Long Island, and upstate New York load pockets.	*More Granular Operating Reserves:* (- / Market Concept Proposed)
2017-2	VI.A.1	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	N/A
Capacity Market – Design Enhancements			
2021-4	VIII.D	Improve capacity modeling and accreditation for specific types of resources.	*Modeling Improvements for Capacity Accreditation:* (Deployment / -) and *NYISO RA Model Strategic Plan* (see below)]

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
2022-1	VIII.E	Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs.	*Valuing Transmission Security:* (Market Concept Proposed)
2022-2	VIII.G	Establish seasonal capacity requirements and demand curves.	*Winter Reliability Capacity Enhancements:* (Market Design Complete / Software Design Specs)
2022-4	VIII.C	Implement more granular capacity zones and a dynamic process for updating the zones.	N/A

I. INTRODUCTION

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2024.[1] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

- Day-ahead and real-time markets that simultaneously optimize energy, operating reserves, and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals that guide decisions to invest in new and existing generation, transmission, and demand response resources (and/or retire uneconomic existing resources); and
- A market for transmission rights that allows participants to hedge the congestion costs associated with using the transmission network.

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to reliably meet the system's demands at the lowest cost. The coordination provided by the markets is essential because of the physical characteristics of electricity. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered.

The NYISO markets have several key features that are designed to allow the power of markets to satisfy the needs of the system efficiently, including:

- Simultaneous optimization of energy, operating reserves, and regulation, which efficiently allocates resources to provide these products;
- Locational requirements in its operating reserve and capacity markets, which play a crucial role in signaling the need for resources in transmission-constrained areas;
- Capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals;
- Ancillary services demand curves, which contribute to efficient prices during shortages when resources are insufficient to satisfy all of needs of the system;
- A real-time commitment system (i.e., RTC) that commits quick-start units (that can start within 10 or 30 minutes) and schedules external transactions. RTC runs every 15 minutes, optimizing over a two-and-a-half hour period.

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1 NYISO MST 30.10.1 states: "The Market Monitoring Unit shall prepare and submit to the Board an annual report on the competitive structure of, market trends in, and performance of, other competitive conditions in or affecting, and the economic efficiency of, the New York Electric Markets. Such report shall include recommendations for the improvement of the New York Electric Markets or of the monitoring, reporting and other functions undertaken pursuant to Attachment O and the Market Mitigation Measures."

- A market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets 15 to 30 minutes ahead of when the power flows in real-time.
- A mechanism that allows inflexible gas turbines and demand-response resources to set energy prices when they are needed, which is essential for ensuring that price signals are efficient during peak demand conditions.
- A real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one-hour period, allowing the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs.

These market designs provide substantial benefits to the region by:

- Ensuring that the lowest-cost supplies are used to meet demand in the short-term; and
- Establishing transparent price signals that facilitate efficient forward contracting and govern generation and transmission investment and retirement decisions in the long-term. Relying on private investment shifts the risks and costs of poor decisions from New York's consumers to investors.

As federal and state policy-makers promote public policy objectives such as environmental quality through investments in electricity generation and transmission,[2] the markets will adapt as the generation fleet shifts from being primarily fossil fuel-based, controllable, and centralized to having higher levels of intermittent renewables and distributed generation. Although large-scale changes in the resource mix currently result primarily from public policies to reduce pollution and promote cleaner generation, the NYISO markets will continue to provide:

- Useful information regarding the value of electricity and cost of production throughout the State, enabling clean energy procurements to select more efficient proposals and transmission planning processes to identify needs appropriately and select the most efficient solutions; and
- Critical incentives not only for placing new resources where they are likely to be most economical and deliverable to consumers but also for keeping conventional resources that help integrate clean energy resources while maintain system reliability.

Therefore, it is important for the markets to continue to evolve to improve alignment between the market design and the reliability needs of the system and public policy goals, to provide efficient incentives to the market participants, and to adequately mitigate market power. Section I of the report provides a number of recommendations that are intended to achieve these objectives.

2 For instance, see the New York's Climate Leadership and Community Protection Act ("CLCPA").

II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2024. It evaluates energy and capacity costs, fuel prices, generation patterns, demand patterns, and significant market events. We also evaluate investment incentives for existing generator types in southeast New York.

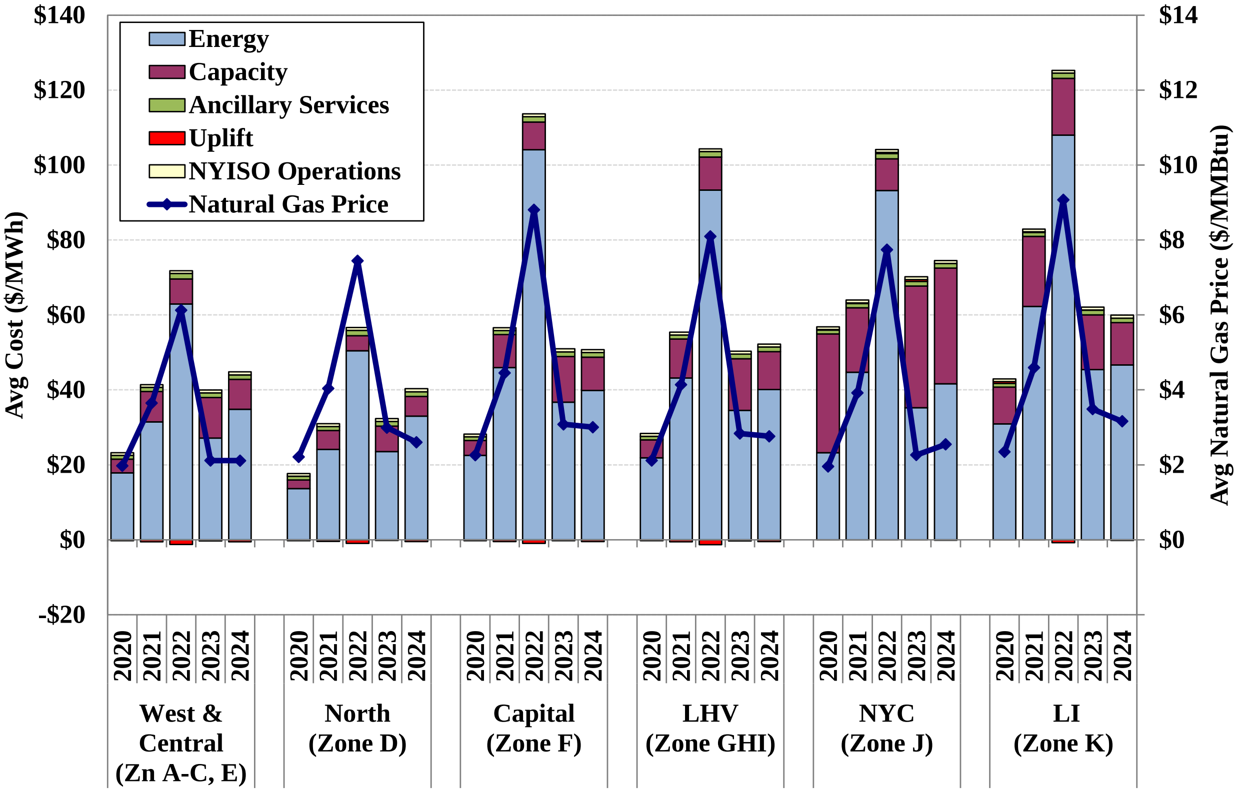
A. Wholesale Market Costs

Figure 1 summarizes wholesale market costs to consumers over the past five years by showing the all-in price for electricity, which reflects the average cost of serving load from the NYISO markets. The major components of this metric include:

- The energy component is the load-weighted average real-time energy price.
- The capacity component is based on monthly spot auction clearing prices and capacity procured in each area, allocated over energy consumption in that area.

All other components are the costs divided by the real-time load in the area.[3]

Figure 1: Average All-In Price by Region
2020 - 2024



3 Section I.A of the Appendix provides a detailed description of the all-in price calculation.

In 2024, average all-in prices ranged from $42 per MWh in the North Zone to over $76 per MWh in New York City. All-in prices rose in most regions because of higher energy costs, which was due to the following factors:

- Average imports from external control areas fell by nearly 200 MW, primarily due to reductions in imports at the Quebec interfaces.
- CO_2 emissions allowance costs rose due to higher Regional Greenhouse Gas Initiative ("RGGI") prices. RGGI prices rose by 54 percent from the prior year to average nearly $21 per ton for the year, which translates to approximately $9 per MWh in marginal costs for a typical gas-fired combined cycle generator.
- Weather conditions, both warmer in the summer and colder in the winter, contributed to an increase (2 percent) in average load.
- Transmission congestion impacted certain regions, especially New York City.

Higher energy prices were partially offset by falling capacity prices in most areas, which fell by 5 percent in New York City and by 23 to 27 percent elsewhere. The reasons for these decreases are discussed in Section VIII.A, but include significantly lower load forecasts and, in some localities, lower Locational Capacity Requirements ("LCR").

B. Net Revenues for Existing Generators

As the resource mix shifts away from conventional generation, it is important for the market to incent retirement of the least valuable generators (rather than flexible resources needed to integrate intermittent generation) and to maintain generation in a reliable condition. We evaluate the current market incentives for conventional technologies in New York. Figure 2 shows the net revenues and the estimated going-forward costs (GFCs) for several existing technology types from 2022 to 2024. To evaluate the financial returns for flexibility, net revenues from day-ahead energy sales are shown separate from net revenues from balancing energy sales (and purchases) and from the sale of operating reserves. To evaluate the financial returns of dual-fuel capability, net revenues from oil-fired operation are shown separately.

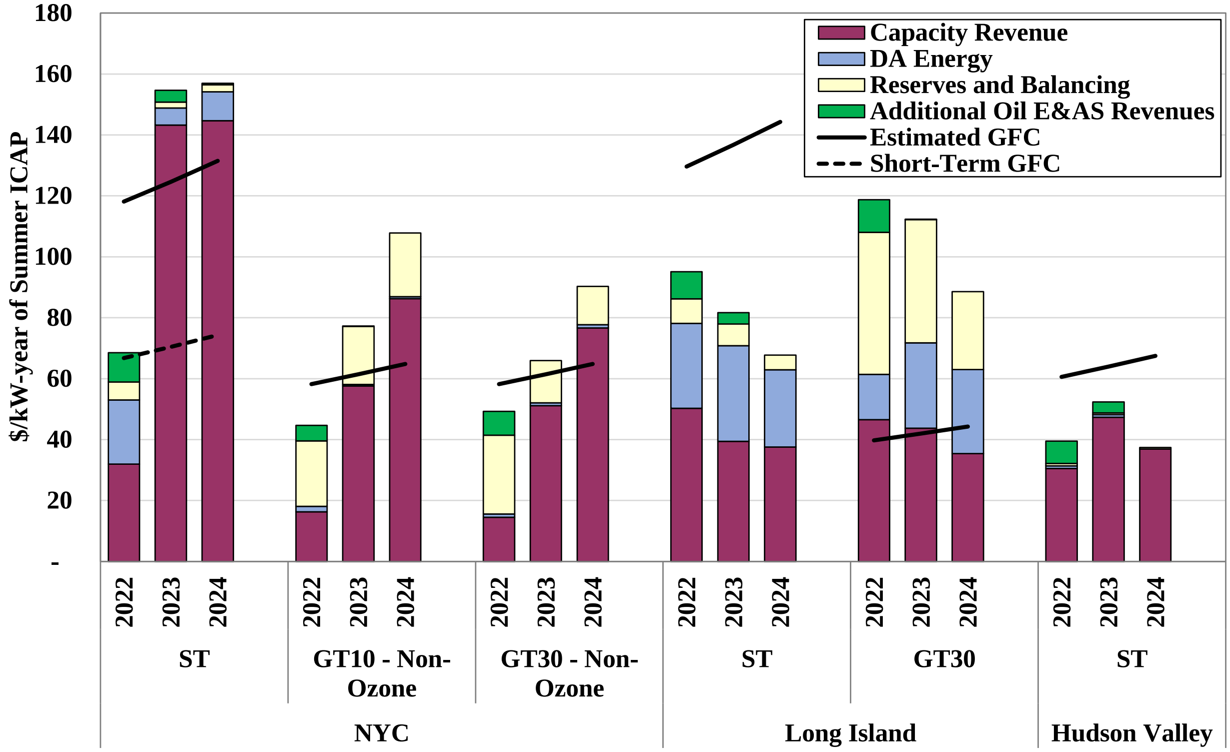
The "Estimated GFC" includes the long-run average cost of maintaining an existing unit in a reliable condition, including plant-level and other costs that may be shared across multiple units.[4] However, a firm may not be able to avoid all such costs by retiring just a single unit, and a firm may be able to avoid substantial costs by deferring maintenance and other capital expenditures in the short-term. Hence, the figure also shows a "Short-Term GFC" for New York City steam units, which excludes major maintenance and other capital expenditures. Even the "Short-Term GFC" includes some plant-level costs that would be difficult to avoid by retiring a single unit.[5]

4 The "Estimated GFC" for existing gas generators is based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

5 The "Short-Term GFC" includes fixed O&M costs, property tax and administrative costs and excludes major maintenance and capital expenses. See Appendix sections VII.A and VII.B for details regarding net revenues.

For gas turbines in New York City, we show revenues for resources that operate only outside of the "ozone season" (May through September). A large amount of gas turbine capacity in NYC has retired, while 565 MW at the Narrows and Gowanus plants will cease operating in the ozone season once they are no longer needed for reliability during peak load conditions to comply with NYSDEC "Peaker Rule" NOx emissions regulations.[6]

Figure 2: Net Revenues and Going-Forward Costs of Existing Units
2022 – 2024



Revenues for existing fossil units were mainly driven by fluctuations in capacity prices. Net revenues for NYC resources increased modestly in 2024 due to higher capacity prices in that area along with higher energy prices. The retirement of significant amounts of peaking capacity in the city contributed to higher levels of localized New York City congestion in 2024. However, net revenues decreased elsewhere primarily due to lower capacity prices systemwide.

Steam turbine units appear to be the most economically challenged of the technologies evaluated. Their average net revenues over the past few years have generally been lower than the estimated GFCs in all areas, though tight supply conditions in New York City have dramatically improved the situation for steam turbines there. Their high operating costs and physical constraints that require long start-up times and run times usually prevent steam units from earning much energy or reserve revenue, except in Long Island.

6 See NYISO Short-Term Assessment of Reliability Report for more information pertaining to the reliability need which necessitated continued operation of these units past 2025.

There is considerable uncertainty regarding the actual price level at which an existing unit owner would choose to retire or mothball. The decision to retire and the actual GFCs depend on a range of factors including whether the units are under long-term contracts, the age and condition of the individual unit, the level of incremental capital and/ or maintenance expenditure required to continue operations, the value of its interconnection rights and CRIS rights, and the owner's expectations of future market prices. In Long Island, steam turbine generators are compensated through long-term contracts, so these units are less-exposed to wholesale prices and may have stronger incentives to perform maintenance. In Hudson Valley, steam turbine generators may have incentives to defer maintenance.

Figure 2 shows that gas turbine units in New York City would have earned more than their going-forward costs in 2024 even if they had operated only outside of the five months of the ozone season. This reflects that capacity prices have risen following gas turbine retirements in late-2022 and early-2023. Nonetheless, not receiving revenues during the ozone season will make it difficult for these resources to remain in service over time, making it urgent for the NYISO to implement market reforms to adequately value winter reliability.

Existing fossil fuel generators face considerable economic and regulatory pressure that are leading some to retire. A key role of the wholesale market is to provide incentives that lead the least valuable units to retire while retaining generators with needed characteristics. The wholesale market should efficiently reward reliability, flexibility, and fuel-security if the New York power system is going to become cleaner as envisioned by policy-makers while maintaining reliability at the lowest possible cost. Hence, we have recommended market enhancements in Section I that would help reward resources more appropriately for these characteristics to help steer investment toward resources that provide the greatest value.

C. Fuel Prices

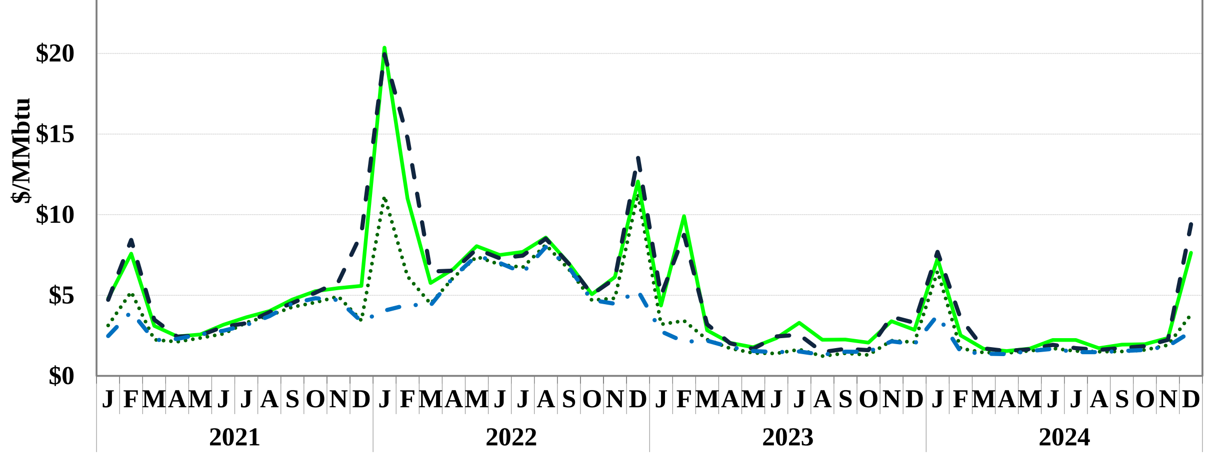
In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. Figure 3 displays monthly and annual natural gas prices from 2021 to 2024 for several key indices.[7]

Average annual natural gas prices for gas pipelines delivering to locations in New York were relatively unchanged in 2024 from the prior year levels. Strong domestic gas production numbers continued to keep prices low across much of the year. Significant changes year-over-year from 2023 to 2024 were mostly driven by transient periods of winter price volatility driven by cold temperatures. This tends to drive natural gas prices higher in the eastern parts of the state more than elsewhere.

7 Section I.B in the Appendix shows the monthly variation of fuel prices and provides our assumptions about representative gas price indices in each region.

Figure 3: Average Fuel Prices and Real-Time Energy Prices
2021 – 2024

	Avg Price per Year				2024 Value vs Prior Years		
	2021	2022	2023	2024	2021	2022	2023
Natural Gas (Tennessee Zn6)	$4.68	$9.20	$3.11	$3.06	-35%	-67%	-2%
Natural Gas (Iroquois Zn2)	$4.36	$8.82	$3.28	$2.90	-34%	-67%	-12%
Natural Gas (Transco Zn6 (NY))	$3.49	$7.04	$1.94	$2.19	-37%	-69%	13%
Natural Gas (Tenn Z4 200L)	$3.38	$5.75	$1.82	$1.83	-46%	-68%	0%



D. Demand Levels

Demand is another key driver of wholesale market outcomes. Higher demand levels drive high-cost peaking resources to set prices more frequently. Additionally, transmission congestion into load centers generally increases as demand levels rise. Lastly, annual peak demand forecasts are used to determine the MW-requirements in the capacity market.

Table 1 shows the following load statistics for the New York Control Area (NYCA) since 2015: (a) annual summer peak; (b) reconstituted annual summer peak; (c) annual winter peak; and (d) annual average load. The reconstituted summer peak incorporates any demand response that was activated during the peak load hour, either by utility deployment or by the NYISO. Therefore, a reconstituted peak load gives a truer sense of the supply resource requirements.

The average load across the system was 2 percent higher than in 2023, but remained in the bottom 50th percentile of values over the past decade. Warmer weather drove up the average load value, but increased penetration of Behind-the-Meter (BTM) solar continues to keep the value low relative to historic levels. Peak demand fell 4 percent from 2023 levels despite the warmer summer this year. Once again, BTM solar was a key driver of this reduction along with a significant peak-shaving contribution from demand response resources. The NYISO estimated that demand response resources shaved nearly 1.2 GW off the peak load and shifted the peak day as reported. As some demand response resources leave the Special Case Resource ("SCR") program and register as Distributed Energy Resources ("DER") going forward, it is more likely that load shaving deployment will shift to holding these resources in reserves.

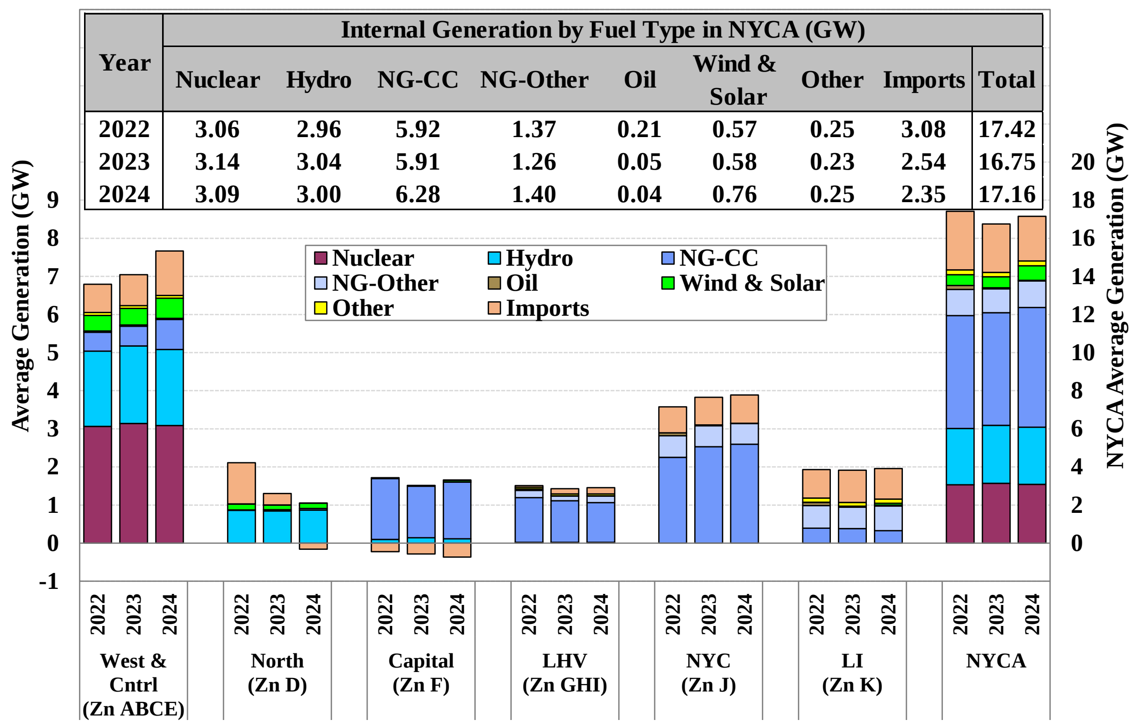
Table 1: Peak and Average Load Levels for NYCA
2015 – 2024

Year	Summer Peak (as Reported)	Summer Peak (Reconstituted)	Winter Peak	Annual Average
2015	31.1	31.1	24.6	18.4
2016	32.1	32.5	24.2	18.3
2017	29.7	29.7	24.3	17.9
2018	31.9	32.5	25.1	18.4
2019	30.4	30.4	24.7	17.8
2020	30.7	31.2	22.5	17.1
2021	30.9	31.3	22.5	17.3
2022	30.5	31.2	23.2	17.4
2023	30.2	30.5	23.4	16.8
2024	28.9	29.8	23.1	17.2

E. Generation by Fuel Type

Variations in fuel prices, retirements and mothballing of old generators, and the additions of new gas resources in recent years have led to changes in the mix of fuels used to generate electricity. Figure 4 displays annual generation by resource type from 2022 to 2024 (including net imports).[8]

Figure 4: Generation by Type and Net Imports to New York
2022 - 2024



Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind & Solar	Other	Imports	Total
2022	3.06	2.96	5.92	1.37	0.21	0.57	0.25	3.08	17.42
2023	3.14	3.04	5.91	1.26	0.05	0.58	0.23	2.54	16.75
2024	3.09	3.00	6.28	1.40	0.04	0.76	0.25	2.35	17.16

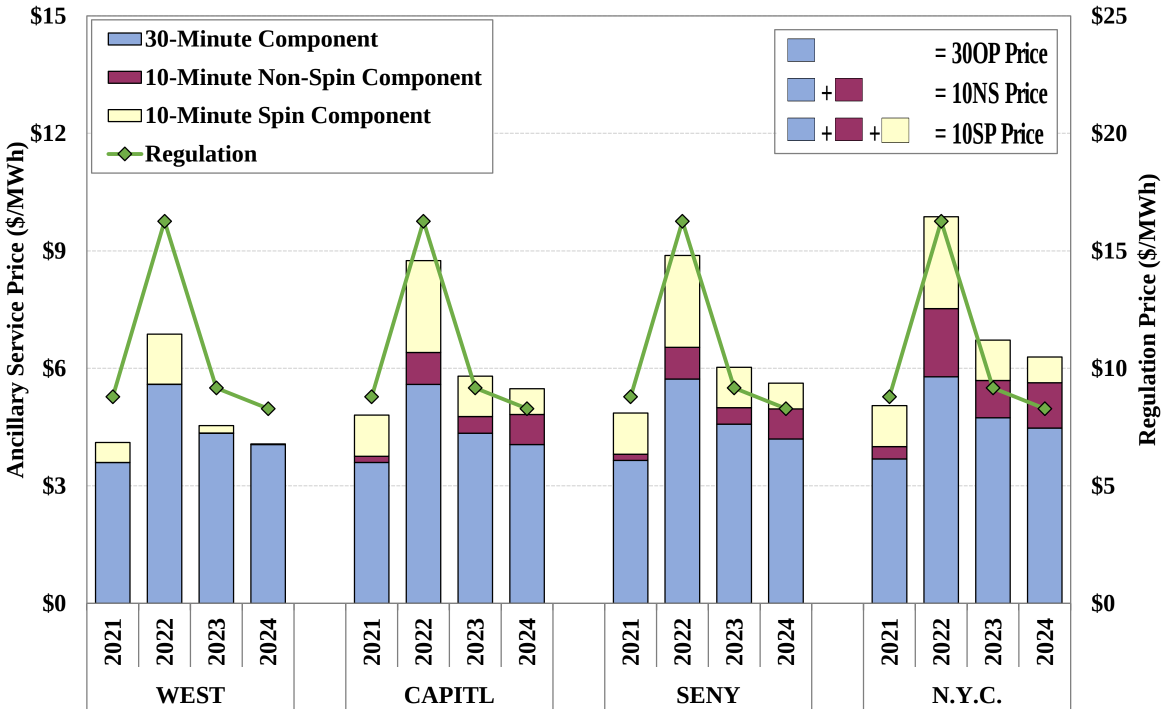
8 Net imports are assigned as follows: (a) Ontario imports to West & Central; (b) Quebec imports to North; (c) imports over the primary PJM interface are split 7, 47, and 46 percent to NYC, Lower Hudson Valley, and West & Central, respectively; (d) net imports over the primary ISO-NE interface are split 55 and 45 percent Capital and Lower Hudson Valley, respectively; and (e) Scheduled Lines where they inject (i.e., Cross-Sound and Neptune Cables, and 1385 Line in Long Island and the HTP and Linden VFT Lines in NYC).

More than half of all internal generation has come from gas-fired resources for the past three years, comprising 52 percent of the total in 2024. Output from Wind and Solar generation resources increased by 32 percent from 2022 to 2024 primarily due to the entry of several new resources since late 2023. These technologies combined accounted for over 5 percent of internal generation this year. Net imports fell by over 200 MW from 2023 because of continued decreases (~500 MW) in net imports from Quebec. Flows from Quebec have fallen to such an extent that net imports, which averaged over 1.3 GW in the import direction as recently as 2021, shifted negative in 2024 (i.e., net export direction).

F. Ancillary Services Markets

The scheduling of ancillary services and energy are co-optimized because part of the cost of providing ancillary services is the opportunity cost of not providing energy when it otherwise would be economic to produce. Co-optimization ensures that these opportunity costs are efficiently reflected in Location Based Marginal Prices (LBMPs) and reserve prices. Despite their small contribution to the overall system costs, the ancillary services markets provide additional revenues that reward resources that have high rates of availability, especially peaking units. Figure 5 shows the average prices of the four ancillary services products by location in the day-ahead market in each of the past four years.[9]

Figure 5: Average Day-Ahead Ancillary Services Prices
2021 - 2024



9 See Appendix Section I.I for additional information regarding the ancillary services markets and detailed description of this chart. Details in that chart are monthly but display the same information.

III. Long-Term Investment Signals and Policy Implementation

A well-functioning wholesale market establishes transparent and efficient price signals to guide generation and transmission investment and retirement decisions. The vast majority of proposed new projects are now driven by New York State clean energy policies and earn a combination of NYISO market revenues, state subsidies, and federal tax incentives. Efficient wholesale markets play a pivotal role in driving investors in clean energy resources to seek the most valuable projects, technologies, and locations. These incentives help avoid wasteful spending and steer investment toward projects that will satisfy state goals at a lower cost to ratepayers. Well-designed markets also encourage investments that complement clean energy projects, such as resources that are needed for grid reliability and flexibility. This section evaluates:

- Investment incentives based on recent market conditions and government policies to promote clean resources (subsection A),
- Long-term incentives for investment in renewable generation (subsection B), and
- Incentives for investment in energy storage resources that facilitate the integration of intermittent renewables (subsection C).

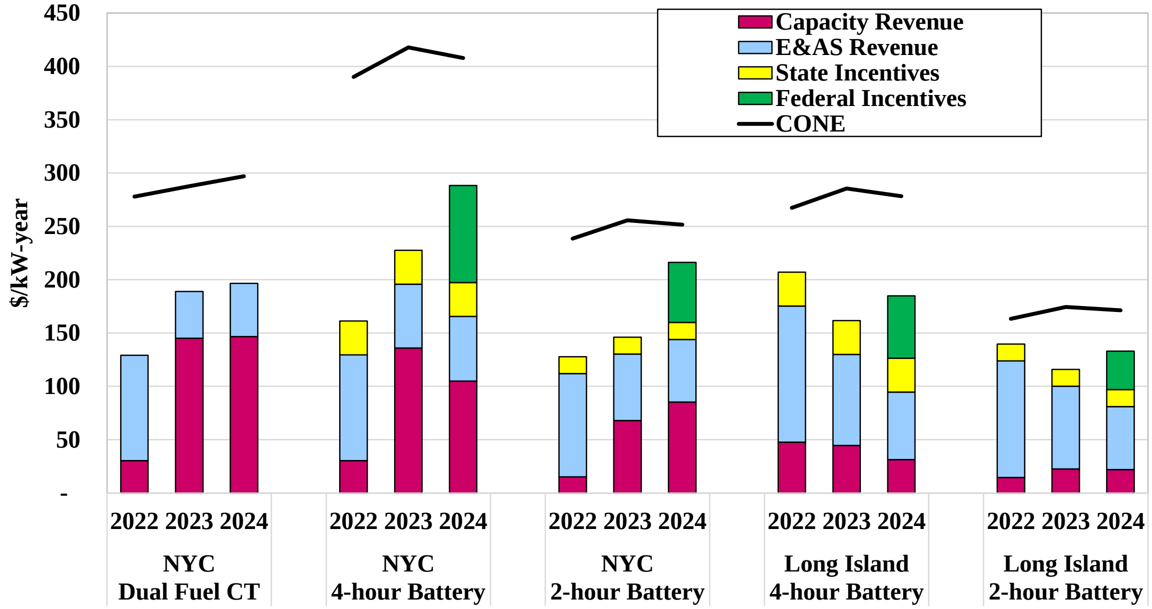
A. Incentives for Investment in New Generation

With the adoption of ambitious state policies to attract large amounts of new intermittent renewable generation, it will be critical to provide efficient investment incentives to two types of developers in particular:

- *Developers of new intermittent renewable generation* – These firms have choices about where to locate and what technologies to use for specific projects. The wholesale market rewards firms that can avoid transmission bottlenecks and generate at times that are most valuable. Developers that expect to receive more in wholesale market revenues will tend to submit lower offers in state solicitations and, therefore, are more likely to be selected.
- *Developers of new flexible resources* – Increased flexibility will be needed to integrate high levels of renewable generation, particularly around critical transmission bottlenecks. The wholesale market provides nodal price signals that differentiate the value of resources based on their locational value and flexibility, thereby delivering the highest revenues to resources that are most effective in complementing renewable generation.

This subsection focuses on how location, technology, and flexibility—all attributes that wholesale markets can value efficiently—play key roles in determining whether a particular project will be profitable to a developer. Figure 6 and Figure 7 show the estimated average net revenues from the NYISO markets, as well as state and federal subsidies, for dispatchable technologies and intermittent renewables, respectively. We compare this to their respective gross cost of new entry (CONE) in 2024. Net revenue is the total revenue that a generator would earn less its variable production costs. When these revenues exceed CONE, investors will recover their capital costs plus a required return based on a typical cost of capital.[10] Revenues and costs for H-Class gas combustion turbines and battery storage are shown in dollars per kilowatt-year, while those of wind and solar resources are shown in dollars per megawatt-hour.[11]

Figure 6: Net Revenue and Cost of New Entry for New Dispatchable Resources
2022 – 2024



The profitability of new generation varies by technology and zone, and it has been influenced by volatility in energy and capacity markets. In addition to market signals, federal incentives play a major role in the projects' profitability. We observe the following for specific technologies:

Gas-fired Combustion Turbines – Estimated annual revenues for a new CT in NYC were below the CONE from 2022 to 2024 despite relatively tight capacity margins in 2023 and 2024. This revenue gap results primarily because of significant increases in the cost of a new CT which occurred post-2021 and were not fully reflected in annual updates to the capacity demand curves approved in the 2020 Demand Curve Reset. Recent permitting decisions suggest a new combustion turbine may not be deemed compliant with State climate law.[12]

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10 The cost of capital for CT and storage technologies was assumed to equal to the merchant weighted average cost of capital (WACC) from NYISO's 2024 Demand Curve Reset study, while the cost of capital for renewables combines the merchant and regulated cost of capital reflecting that subsidy payments carry lower risk than market revenues earned by these projects. Costs and revenues for the CT reflect a 7HA.02 Frame unit, assumed to be at a brownfield site in NYC. See Appendix Section VII.C.

11 Details on estimated net revenues can be found in Appendix Section VII. See subsection C for further discussion of battery storage net revenues. We estimate state incentives for storage using the levelized value of the $75 per kWh from NYSERDA's Bulk Storage Incentive, which would have been available to projects during the study period. The PSC is currently considering a new bulk incentive program for energy storage.

12 See permit denial letters from New York Department of Environmental Conservation for Astoria Replacement and Danskammer Generating Station projects available at link, and link, respectively.

Energy storage – Market revenues of battery storage have historically been far below levels needed to justify investment. In recent years, cost pressures and rising interest rates have resulted in rising storage CONE values. However, standalone storage projects became eligible for the 30 percent federal Investment Tax Credit beginning in 2023, offsetting cost pressures. We estimate a smaller revenue shortfall for 2-hour storage than 4-hour storage because of the 2-hour storage facility has significantly lower costs but modestly lower revenues. The economics of storage are heavily supported by state and federal incentives. We estimate that in 2024, about 33 to 43 percent of storage revenues in New York City and 39 to 49 percent in Long Island would be from subsidies (including tax incentives).

In the long term, storage revenues are expected to be supported by rising intermittent renewable penetration, but capacity revenues will be negatively affected if large amounts of new storage driven by state mandates cause the Capacity Accreditation Factors (CAFs) of storage to decline.[13] The economics of longer duration batteries may become more favorable if the CAFs of shorter duration resources face steeper declines as battery penetration grows. This illustrates how future changes in state and federal policies pose risks to clean resource developers that enter the market before such changes are enacted.

Figure 7 shows estimated average revenues of intermittent renewable technologies in 2022 through 2024 compared to their estimated Cost of New Entry (CONE). REC revenues reflect the reported price of NYSERDA Tier 1 RECs for land-based renewables, and estimated OREC payments under the Index REC framework for offshore wind. CONE values are estimated based on generic cost data from public sources. We compare each technology's estimated CONE to a CONE value implied by the average Index REC strike price for projects of that technology with active publicly reported contracts with NYSERDA. The Index REC structure is designed to provide a hedge against changes in energy and capacity prices.[14]

Estimated net revenues of renewable technologies were generally sufficient to recover the resources' estimated CONE. This is primarily due to state and federal subsidies, which accounted for approximately 56 percent of revenues for land-based wind, 48 percent of revenues for solar PV, and 59 percent of revenues for offshore wind.

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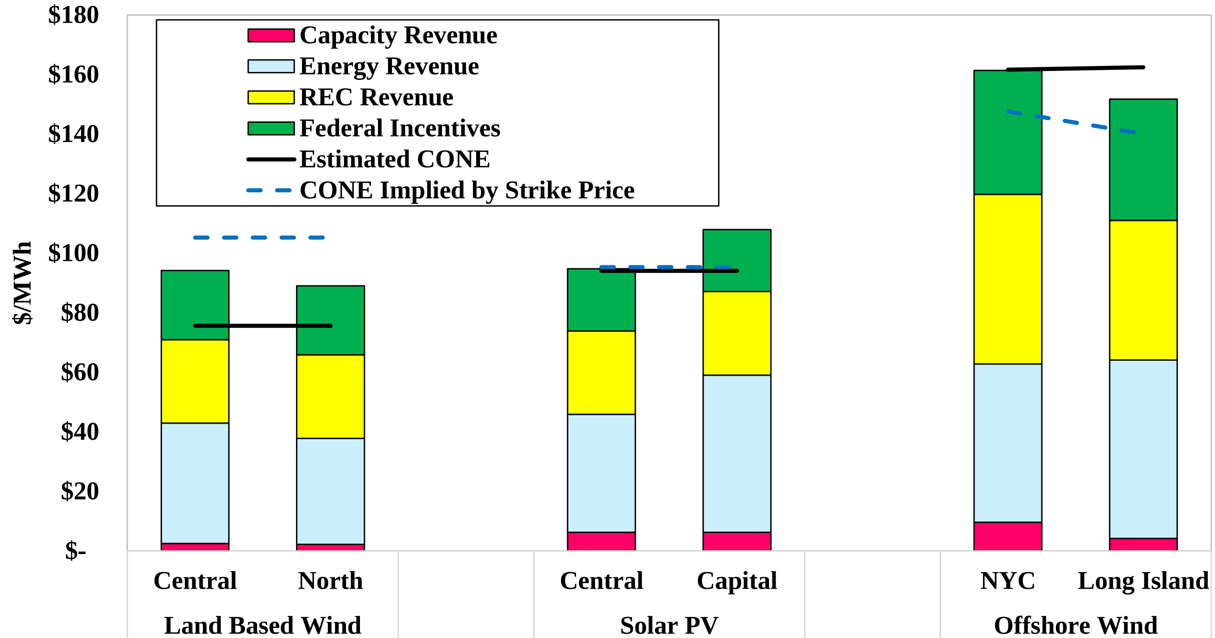
13 The final CAFs for the 2024/2025 capability year in New York City are 55.93 percent (2-hour) and 68.84 percent (4-hour), and in Long Island are 52.76 percent (2-hour) and 78.94 percent (4-hour). Before adoption of NYISO's new accreditation rules, capacity value for 2-hour and 4-hour resources was set at 45 percent and 90 percent, respectively. See capacity accreditation webpage, here.

14 See Appendix VII.C for detailed assumptions. Average strike prices include projects with active new capacity projects (excluding repowerings) and Index REC prices reported by NYSERDA as of March 2025. NYSERDA reports contract prices in nominal dollars; we convert these reported prices to a real \$2024 price with equivalent present value over the lifetime of the project. We add estimated revenues from federal incentives to the strike price to derive the 'implied' CONE. For offshore wind, strike prices include the effects of contract provisions that reduce the strike price for projects receiving federal incentives.

Figure 7: Net Revenue and Cost of New Entry for New Renewable Generation
2022 – 2024



Revenues of renewables were generally sufficient to justify new investment when including state and federal incentives. Currently active Index REC strike prices for solar projects are consistent with the estimated CONE value, while the CONE implied by active offshore wind contracts is somewhat lower than the estimated CONE (possibly reflecting developers' expectation of cost declines). The CONE implied by strike prices of active land-based wind contracts is significantly higher than the estimated cost of wind projects. This may be due in part to the impact of site specific development costs for land based wind in New York. It also likely reflects developers' expectations that their total market and REC revenues under the Index REC framework will differ from their contract strike prices. We discuss the status of renewable investments and the market risks of projects with Index REC contracts in the next subsection.

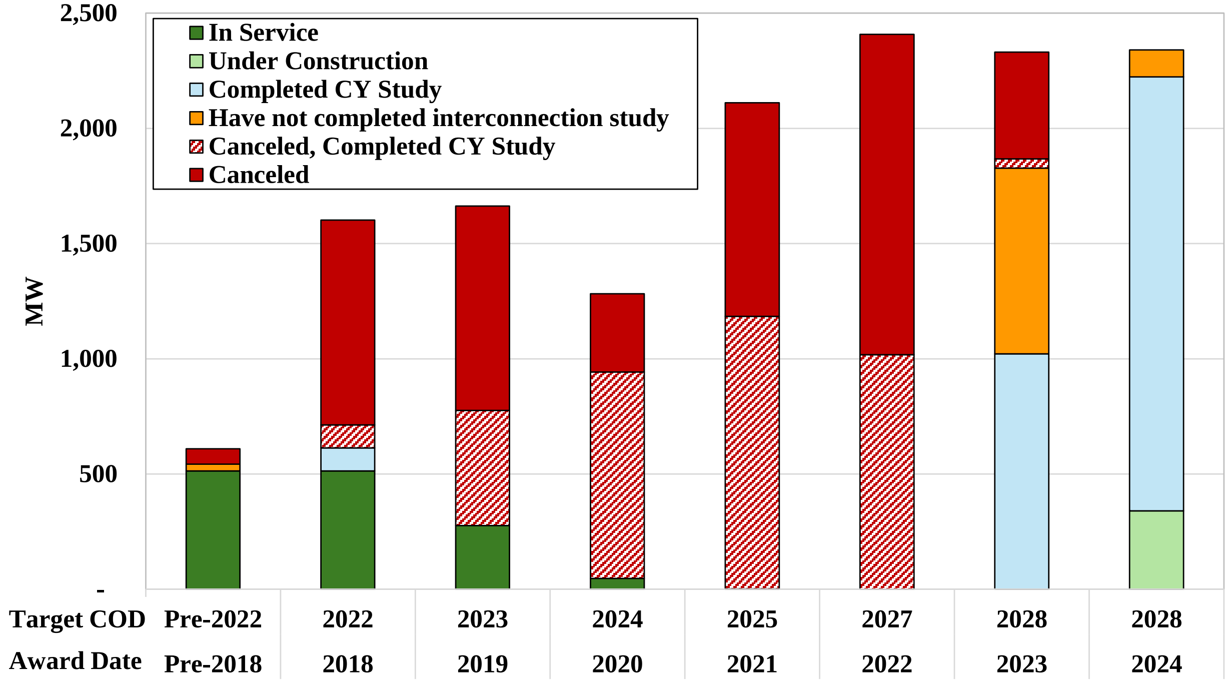
B. Long-Term Incentives for Investment in Renewable Generation

New York's Climate Leadership and Community Protection Act (CLCPA) requires transformational changes in the state's resource mix towards clean energy and away from polluting sources. The CLCPA established a 70 percent clean energy target by 2030, along with various technology-specific requirements. State and federal incentives account for a large portion of the compensation for these resources. However, energy and capacity markets still provide critical price signals that differentiate resources based on their value to the power system, encouraging the most economic projects to come forward and providing sustained revenues after state and federal incentives end. This subsection reviews the progress towards policies to promote clean renewable energy projects in NYISO and discusses how current investment incentives are affected by both current and future state policies.

1. Status of Clean Energy Investment in NYISO

Figure 8 shows a summary of land-based renewable projects that have been awarded contracts to provide renewable energy credits (RECs) under New York's Clean Energy Standard (CES) and their statuses in NYISO's interconnection queue as of March 2025. Awards that NYSERDA indicates have been canceled are shown in red.[15] This figure does not include awards from NYSERDA's 2024 solicitation which have not been made public at time of writing.

Figure 8: Summary of Land Based Wind and Solar Project Statuses



Overall, while over 14 GW of Tier 1 awards have been announced under the CES: just 9 percent have entered service, while 61 percent have been canceled and most of the remainder have not yet moved forward with construction. Land-based wind account for 839 MW of the 1,353 MW of projects that have entered service under the CES, while over 67 percent of remaining capacity with active Tier 1 contracts are solar. In addition, the State has promoted offshore wind and energy storage to meet CLCPA goals:

- *9 GW of offshore wind by 2035* – NYSERDA awarded contracts to seven projects totaling 8.3 GW, but all seven initial awards have been canceled. Two of the canceled projects (1.7 GW) were re-awarded at higher Index REC strike prices in a 2023 solicitation. The two re-awarded projects (i.e., Empire Wind and Sunrise Wind) have completed the Class Year interconnection process and NYSERDA anticipates they will enter service in 2026.

15 Data taken from NYSERDA's renewable project database (see here) and NYISO's Interconnection Queue as of March 2025. Initial COD Targets are from NYSERDA announcements of solicitation results (see here). For projects that canceled original contracts and were subsequently re-awarded, the original award is included as 'Canceled' and the latest award is included based on its current status.

- *6 GW of energy storage by 2030* – The NYPSC has adopted a target of 6 GW by 2030, including at least 3 GW participating in the NYISO markets. A large number of storage projects are in the interconnection queue, but few have been completed and none are currently listed as 'Under Construction'. NYSERDA has indicated that 630 MW with an average duration of 3.4 hours have been awarded incentives under the state's bulk storage incentive program since 2019.[16] Of these projects, 31 percent have been canceled and just 10 percent have been completed. The NYPSC recently approved a new three-year process to procure 3 GW of bulk storage projects, with solicitations beginning in 2025.

The project development track record summarized above highlights that a large share of the awarded REC contracts have not progressed as expected. Key drivers include:

- *Cost Increases* – Many projects reported unexpectedly high development costs and interest rates in the past two years which rendered their original awarded REC prices insufficient to justify investment. We estimate that the cost of new entry increased by ~32 percent for solar PV and land-based wind between 2021 and 2023. Upgrade costs required to receive CRIS rights have been significant for some projects.
- *Market Risks* – The acceleration of State procurement targets and the pattern of awards with increasingly attractive pricing terms in recent years have increased market risks for earlier-contracted projects (since these factors tend to reduce future energy prices). We discuss these market risks further in the next subsection.
- Weak Non-Performance Penalties – Given the risks of development cost increases and falling energy prices, if contracts have relatively weak financial penalties for non-performance, then developers have incentives to submit more aggressive (i.e., low-priced) offers in NYSERDA RFPs. Consequently, awards are more likely to go to projects that are relatively unlikely to be constructed.

The State has awarded many contracts under the CES, but deployment of renewable generation and storage has lagged expectations. Contracted projects have faced headwinds including permitting opposition, interconnection costs and delays, rising construction costs, and effects of the COVID-19 pandemic. NYSERDA has modified the REC contract structure to reduce financial risks to developers from variations in wholesale market conditions, but energy price uncertainty continues to be a significant risk for developers.[17] The remainder of this subsection evaluates NYISO market incentives for investment in renewable generation.

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16 See "Retail and Bulk Energy Storage Incentive Programs Reported by NYSERDA: Beginning 2019" at data.ny.gov, available here.

17 NYSERDA noted in 2020 that "a substantial portion of the projects within this cohort have encountered delays in obtaining financing" for reasons that include declining market prices and permitting. A program evaluation commissioned by NYSERDA lists "financial viability of the project at the bid price" as a driver of project delays and attrition. See NYSERDA August 10, 2020 Petition in NYPSC Case 15-E-0302, at p. 7. Conversion of Fixed REC contracts to Index RECs mitigates but does not eliminate projects' revenue risks.

2. Market Risk for Renewables with State Contracts

Since the earliest awards shown in Figure 8, State and federal policies to promote renewables have changed dramatically. Projects awarded before 2020 were proposed when State policy was to obtain 50 percent of energy from renewables by 2030. As State policies have become more ambitious, anticipated energy and capacity net revenues have declined, requiring higher State and federal subsidy levels to support new clean projects. However, projects that are constructed before the announcement of a new policy goal and that rely on wholesale market revenues will be harmed by the resulting decline in energy and capacity net revenues. This may affect projects that won earlier solicitations by hampering their ability to obtain financing and reducing their incentives to complete the permitting and construction of the project.[18]

New York's procurements for renewable energy have generally been designed to hedge against some market risks while retaining incentives for developers to maximize project value. Most large-scale renewables under contract with NYSERDA will receive payments under the Index REC structure. Under this structure, the project's REC price in each month is equal to a fixed strike price minus 'index' energy and capacity prices derived from zonal average prices. Hence, the project is hedged against changes in overall energy and capacity prices, but faces two major market risks related to its location and generation pattern:

- *Nodal Discount* – Revenues to renewables will deviate from their Index REC strike price if the LBMP at the project's location differs from the capacity zone where it is located due to transmission constraints; and
- *Technology Discount* – Revenues of renewables will deviate from the Index REC strike price if prices during hours when the renewable resource generates are lower than the average price across all hours. For example, if high wind penetration in an area causes the zonal price to be lower during high-wind hours, wind generators will face a technology discount.

Figure 9 shows the average zonal and nodal discounts for land-based wind, solar and offshore wind in selected zones in recent years. Technology discounts are calculated as the difference between the generation-weighted zonal real-time LBMP and simple average day-ahead LBMP.[19] The circles show the difference between the generation-weighted real-time nodal LBMP and the all-hours day-ahead average LBMP at individual generator locations (technology and nodal discount). The values shown reflect average discounts in 2022 through 2024 for wind and 2024 only for solar (for which few projects were in service in earlier years).

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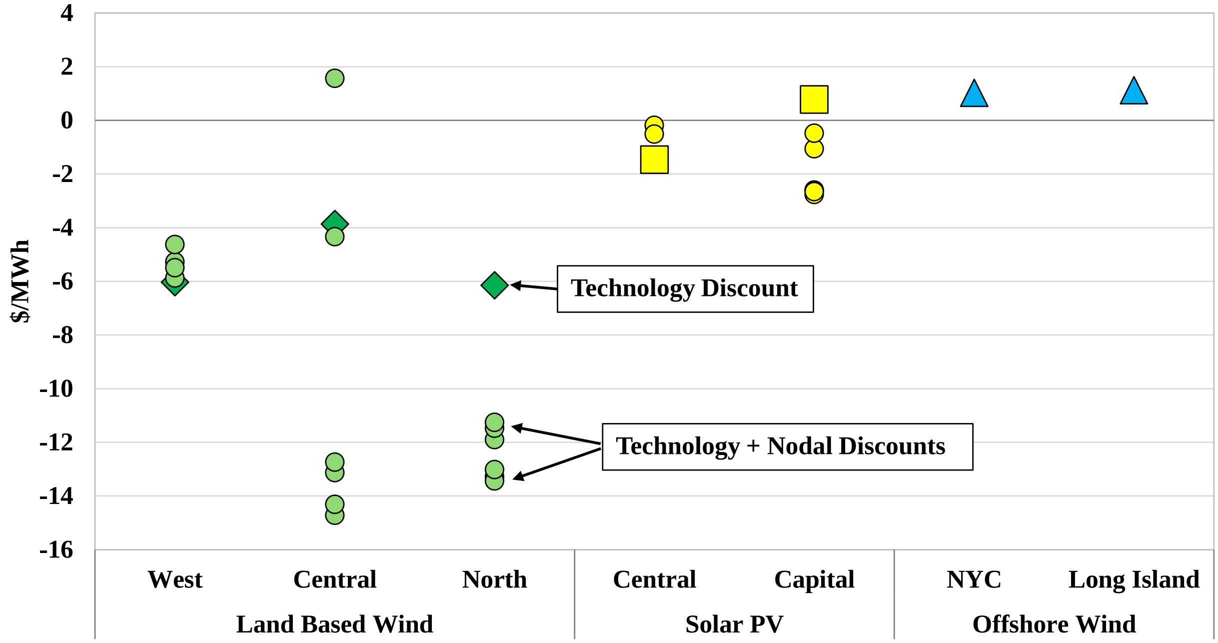
18 In late 2020, the NYPSC issued an order authorizing renegotiation of REC contracts awarded from earlier solicitations to use an Index REC structure providing greater protection from market risk, acknowledging that adverse market conditions had limited the ability of contracted projects to obtain financing. See here.

19 Actual average generation profiles are used for land-based wind and solar, while a generic generation profile is used for offshore wind

Figure 9: Renewable Technology and Nodal Discounts, 2022-2024



Large technology and nodal discounts appear at almost all locations with existing land-based wind units, including: up to $6 per MWh in Zone A, $15 per MWh in Zone C, and $14 per MWh in Zone D. These discounts are caused by generation during low-priced hours and transmission congestion that is exacerbated by high wind output. Under the Index REC contract structure, projects at these locations would earn total revenues (including NYISO market revenues plus REC revenues) below their Index REC strike price. Large nodal discounts for land-based wind projects may explain why recent Index REC strike prices for land-based wind projects exceed the estimated cost of new entry by approximately $30 per MWh (see Figure 7 earlier in this section).

Technology and nodal discounts for solar PV and offshore wind were much smaller (or negative) than for land based wind in 2024. However, our analysis NYISO's 2023 Outlook study found that as deployment of these technologies rises in the future, technology discounts are expected to grow as periods of high renewable output coincide with lower LBMPs.[20] Especially large discounts are projected to emerge for solar PV if large amounts are deployed in the coming decade as current state contracting patterns indicate. Our comparison of estimated renewable CONEs to strike prices of active projects in 7 suggests that solar PV strike prices do not include significant cushion against the emergence of technology and nodal discounts. This increases the financial risks to these projects and the likelihood that awarded contracts are ultimately canceled.

Based on the preceding analyses, we draw the following conclusions:

- NYISO market signals support efficient achievement of renewables targets by signaling the non-REC benefits of competing projects. Exposure to market risks incentivizes

20 See MMU Review of 2023-2042 System & Resource Outlook, available here.

investors to avoid projects in oversaturated locations or technologies. This will lower the cost of achieving policy objectives as projects earning higher market revenues require less support from the state.

- Use of long-term PPAs to satisfy clean energy goals create risks for current renewable projects. Future projects that receive higher levels of state support will impact the market revenues of earlier entrants by increasing technology and nodal discounts.[21] This risk may lead to developers requiring higher Index REC strike prices or reconsidering whether to invest in a project. Policy initiatives that work through transparent market signals reduce these risks and are likely to achieve their objectives at a lower overall cost.

C. Long-Term Incentives for Investment in Storage

Bulk storage deployment has been slow despite the establishment of a State energy storage procurement target and incentive programs in 2018. Subsection A suggests that potential storage revenues have been insufficient to justify investment, even after accounting for state incentives.

The New York State PSC recently adopted a proposal to begin annual solicitations for bulk storage projects beginning in 2025 to support the State's target of 6 GW of energy storage by 2030. The proposal recommends a new Index Storage Credit contract structure that would partially hedge variations in NYISO energy revenues of storage projects.[22] This structure would reduce (but not eliminate) market risk faced by storage developers, potentially accelerating deployments. Early storage developers also face risks that if future storage procurements make higher contract payments, it will tend to shrink expected energy payments to existing projects. This subsection examines potential NYISO market revenues of storage projects and how they could be affected by accelerated storage deployments.

1. Market Signals for Storage – Energy & Ancillary Services

Our net revenue estimates from Figure 6 of this section suggest that the largest potential source of revenues for energy storage is from the capacity market, but energy and ancillary services are also major revenue sources. If state-mandated storage deployment causes capacity accreditation factors (CAFs) of storage resources to decline, storage resources may rely more heavily on energy and ancillary services in the future.

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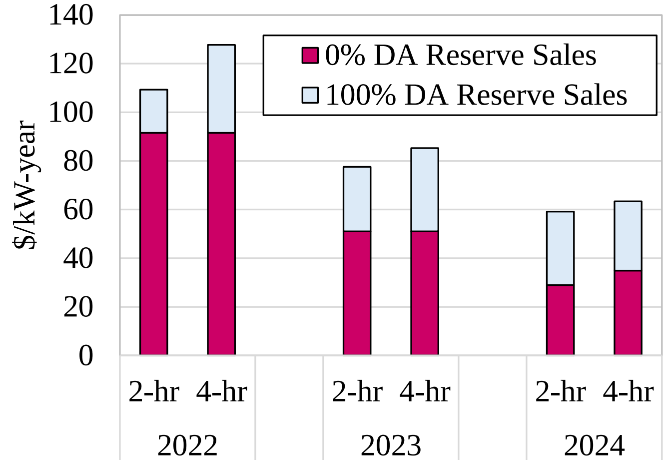
21 A related phenomenon is that future projects with higher REC payments than existing resources may profit by 'undercutting' the negative offer of the lower-REC project in NYISO's merit order dispatch, causing the new project to earn profit by "cannibalizing" the REC of the earlier project. See "MMU Review of 2021-2040 System & Resource Outlook", available here.

22 See "New York's 6 GW Energy Storage Roadmap 2024 Update", March 15, 2024, NYDPS Case 18-E-0130.

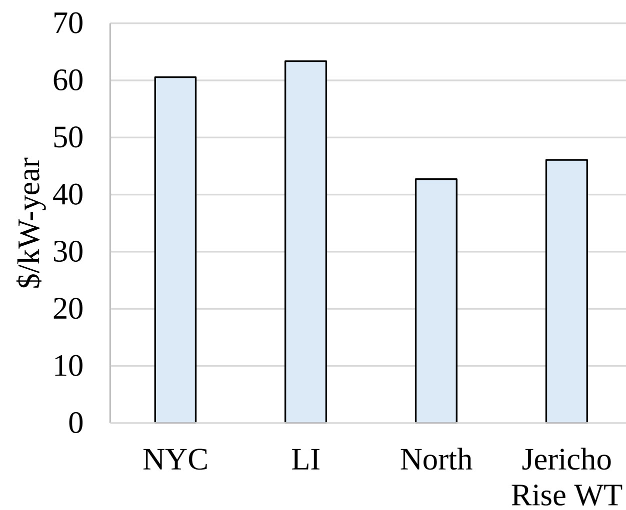
Figure 10 and Figure 11 show variation in estimated net energy and ancillary services revenues for storage based on duration, location, and bidding strategy. Figure 10 shows estimated net energy and ancillary services revenues for 2- and 4-hour battery storage in Long Island using alternative bidding strategies. We model storage revenues assuming that the battery offers its capacity as 10-minute spinning reserves in the day-ahead market, then self-schedules to charge or discharge in the real time market to take advantage of energy arbitrage and real-time reserve opportunities.[23] If the battery sold day-ahead reserves, it is required to maintain at least one MWh of charge to support its obligation for each MW of reserve sales. Figure 10 shows how storage revenues change depending on whether its spinning reserve capacity is offered in the day-ahead reserve market.

Figure 10: Estimated Storage E&AS Revenues Long Island, 2022-2024



This analysis shows that revenues under all strategies were highest in 2022, which had higher and more volatile energy prices than 2023 and 2024. Additionally, offering a larger share of the battery's capacity as day-ahead reserves would have resulted in much higher revenues. Acquiring a day-ahead reserve schedule constrains the ability of the battery to take advantage of real-time arbitrage opportunities in our model, but this would not have offset the higher revenues associated with selling reserves. Finally, a four-hour battery would have earned only $10 per kW-year more on average compared to a four-hour battery, when following the highest-revenue strategy (i.e., the 100 percent day-ahead reserve sales strategy).

Figure 11: Estimated Storage E&AS Revenues



These results suggest expected energy market revenues for batteries are currently dependent on day-ahead reserves. Strategies to increase flexibility for real-time energy arbitrage, such as

23 We assume that the battery operator lacks perfect foresight of real-time market prices. Instead, we develop threshold prices at which to charge or discharge using an algorithm that considers the day-ahead forecast, RTC forecast, and backward-looking prices from the week prior to each operating day.

reducing day-ahead reserve commitments or using a longer-duration battery, did not improve revenues relative to costs. This dependence may imply significant risk for the revenues of battery projects caused by large-scale storage procurement mandates.

Figure 11 compares energy and ancillary services revenues in 2024 across four locations, assuming 100 percent of capacity is offered in the day ahead reserves market. Revenues were highest in downstate zones. Revenues at the Jericho Rise WT location (a generator bus in the North zone) were modestly higher than revenues based on the zonal price, despite the fact that negative prices occurred more frequently at the nodal than zonal level (7 percent vs. 1 percent of real time hours, respectively). Negative prices caused driven by wind curtailment may present limited opportunities for storage because they are often clustered in many consecutive hours.

In the long term, increased deployment of intermittent renewables should increase the potential energy revenues for storage resources by increasing energy price volatility. We have previously found that energy revenues of storage increase substantially when solar resources cause negative prices to occur frequently.[24] Intermittent resources may also eventually contribute to higher operating reserve requirements. Hence, energy and reserve markets are likely to signal the need for storage investment as the penetration of renewable resources increases.

2. Market Signals for Storage – Capacity Value

Beginning in the 2024/25 capability year, NYISO accredits all capacity suppliers based on their marginal impact on reliability.[25] In 2024, the capacity accreditation factors (CAFs) were 53 to 56 percent for 2-hour storage and 65 to 79 percent for 4-hour storage resources, depending on location.[26] The CAFs will be updated each year to account for changes in the system. Future capacity revenues of storage will be greatly affected by changes in CAFs, which reflect the effectiveness of additional storage for meeting the reliability needs of the system. State-driven changes to the NYISO system could have major implications for storage CAFs, including:

- *Renewable and storage mandates*: We have previously found that marginal capacity value of storage will tend to decline as storage penetration grows, requiring longer duration to provide equivalent value. On the other hand, deployment of certain types of renewables (particularly solar) tends to increase the marginal value of storage. Hence, the efficient amount of storage deployment is tied to the pace of renewable development.
- *Seasonal reliability risk*: As discussed in Section VIII.G, tightening winter fuel conditions combined with state policy to promote electrification of winter heating could lead to reliability risk shifting towards winter in the coming decade. The requirements of

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24 See our Review of the 2023-2042 Outlook study, available here.

25 See FERC Docket ER22-772, Section VIII.D, and Appendix Section VI.I.

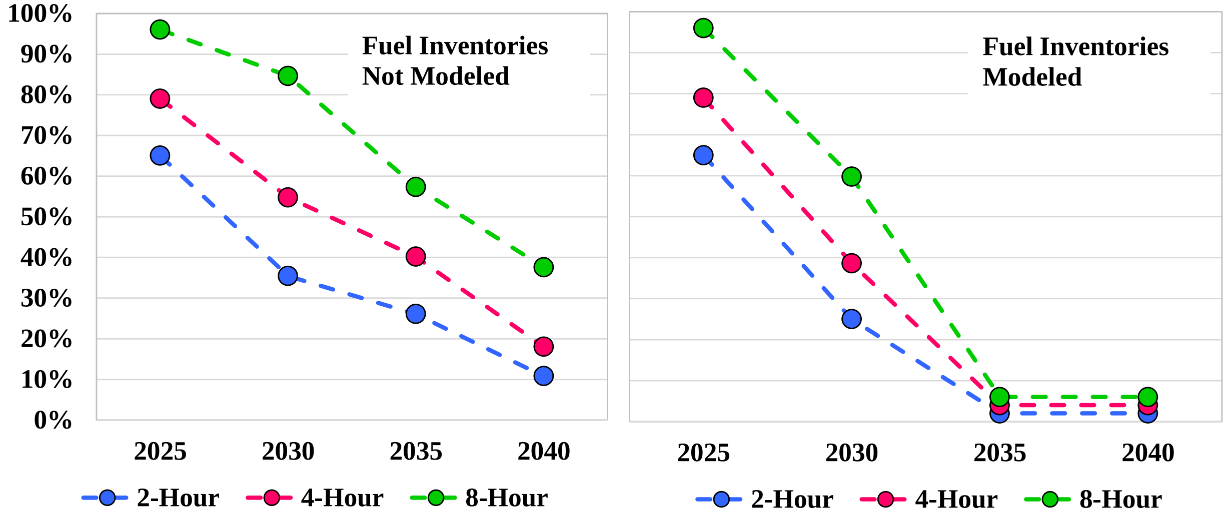
26 See NYISO's capacity accreditation webpage, available here.

a winter-risk system may differ from today's system due to variation in load profiles and fuel security risks associated with limitations on the inventories of oil and dual fuel units.

Figure 12 shows simulated marginal capacity value of 4-hour storage in New York City in a future scenario designed to meet state policy mandates, based on results of Potomac Economics' Resource Adequacy Model ("PE-RAM"). The simulated system is based on the resource mix from NYISO's 2023-2042 System & Resource Outlook policy case, which reaches a 100 percent emissions free electric system with large amounts of intermittent resources and storage by 2040. We estimated marginal storage capacity value both with and without explicit modeling of limited fuel inventories in winter.[27]

Figure 12: Storage Marginal Capacity Value by Duration and Quantity

New York City



This analysis shows that in both scenarios the marginal capacity value of 4-hour storage declines as deployment grows, although it falls much more rapidly in the Fuel Inventories Modeled scenario. This is because reliability needs in this scenario are driven by shortage of stored fuel inventories of oil and dual fuel units in extreme winter conditions. Batteries in this scenario create extra demand when they attempt to recharge during cold periods when stored oil is

27 The values in this figure were generated using Potomac Economics' proprietary resource adequacy model, PE-RAM. PE-RAM is a resource adequacy model that performs an hourly chronological simulation of supply margins and load shedding. It models multiple simulation years and considers different combinations of generator forced outages and load forecasts, in addition to transmission limits between zones, intermittent resource profiles and energy storage charging and dispatch. We performed model runs for the years 2030, 2035 and 2040 and interpolated values in between. The modeled scenarios are based on the resource additions from the preliminary State Scenario of NYISO's 2023 Outlook study, with a delay applied to achievement of clean energy targets by 2030 in line with recent projections by New York state. See Appendix Section VI.E for modeling input details. While PE-RAM will not produce results identical to NYISO's GE-MARS model used in calculation if market CAFs, it demonstrates the directional impact of rising battery penetration and rising winter load even in the presence of very high solar PV penetration.

consumed in nearly all hours, causing fuel inventories to be depleted more quickly and reducing their marginal value. The marginal value of storage declines in the long-term even in the Fuel Inventories Not Modeled scenario because the deployment of large amounts of storage to replace existing fossil resources causes prolonged reliability needs to emerge in periods of low intermittent renewable output.

These observations suggest that future capacity market revenues of storage will be affected by the level of storage deployment and the seasonal pattern of reliability risk – particularly if winter reliability risk is driven by fuel security concerns. Procurement mandates that are insensitive to the marginal reliability benefit of additional storage could result in major capacity value risk for earlier entrants (if the risk of CAF changes is allocated to developers) or higher than expected subsidy payments (if the risk of CAF changes is allocated to consumers).[28]

Conclusions on Energy Storage Incentives

The analyses in this section indicate that current market prices are likely too low to support investment in energy storage, even after considering state and federal incentives that comprise nearly 40 percent of revenues. The future market revenues of storage will primarily depend on capacity and operating reserve revenues. The value of storage for providing these products and storage developers' future revenues may be eroded if centralized procurements result in levels of investment that far outpace efficient quantities.

28 In 2022, NYSERDA and NYDPS proposed a series of annual bulk storage procurements beginning in 2024, for which the preferred contractual arrangement would provide an imperfect hedge against market risk similar to the Index REC structure used for renewables. See "New York's 6 GW Energy Storage Roadmap 2024 Update", filed March 15, 2024 in NYDPS Case 18-E-0130.

IV. Deliverability Testing and Transmission Planning Processes

New transmission investment in the bulk power system occurs through centralized planning processes including the NYISO's Comprehensive System Planning Process and its deliverability testing process to identify upgrades funded by resource developers. We evaluate the performance of these processes and consider potential opportunities for improvement. Subsection A contains our evaluation of the deliverability study component of the interconnection process, while Subsection B discusses NYISO's centralized planning processes.

A. Deliverability Study Process for New Resources

NYISO's interconnection process plays a key role by ensuring that new resources can reliably interconnect to the network and be deliverable to load. All new generation and storage projects must complete the deliverability testing process, which identifies the upgrades needed for a project to be deliverable. Upgrade costs are allocated to the interconnecting projects, which developers must consider in deciding whether to move forward with a project. If the upgrades are not efficient or new projects bear a disproportionate share of upgrade costs that benefit the system, this will deter efficient new investment. This subsection discusses the following concerns with the deliverability testing process and provides a summary of our conclusions:

- Inefficient Upgrade Project Selection – The process requires new resources seeking CRIS to be deliverable throughout the Capacity Region. However, if the SDU projects selected are not economic, the deliverability test could impede efficient generation investment.
- Deterministic Test Methodology – The test is based on a single peak demand scenario, which tends to over-estimate transmission used by intermittent and storage resources. It also models a dispatch in each capacity zone that can be extremely unrealistic.
- Resource Mix Assumptions – The test does not accurately consider how future investments will impact a project's future deliverability, leading some projects to be assigned excessive SDUs and others to be granted excessive CRIS rights.
- Favoring Existing Resources Over New Projects – New resources are required to make costly deliverability upgrades to sell capacity, instead of having an option to compete with existing resources in the same area for available headroom.

Background on the Study Process

NYISO recently redesigned its interconnection study process, resulting in the initiation of the first "Cluster Study" in 2024. Previously, the most significant interconnection study was known as the Class Year process. Both the Cluster Study and Class Year processes were designed to jointly study the impacts of a group of proposed projects and allocate network upgrade costs required for them to reliably interconnect and participate in the NYISO markets. The Cluster Study is intended to improve upon the previous process with a streamlined set of studies, shorter timelines, more information provided to developers early in the process, and improved incentives for the progression of projects that are more likely to complete the process.

The Cluster Study identifies the following categories of upgrades (these same categories were identified under the Class Year process):[29]

- Connecting Transmission Owner' Attachment Facilities (CTOAF): dedicated facilities required to connect the project to the transmission owner's network.
- System Upgrade Facilities (SUF): network upgrades needed for the group of studied projects to comply with NYISO's Minimum Interconnection Standard (MIS). Projects must agree to pay the cost allocated to them for identified upgrades to receive the right to sell energy (ERIS). The MIS identifies adverse reliability impacts of interconnecting the project, but it considers normal operating actions that would avoid these impacts (e.g. reduction in output or curtailment of the resource as needed).
- System Deliverability Upgrades (SDU): upgrades needed for resources to be deliverable under NYISO's Deliverability Interconnection Standard (DIS). Projects must pay for identified upgrades to receive the right to sell capacity (CRIS). The DIS ensures that new projects receiving CRIS rights and existing resources can simultaneously deliver their output throughout the capacity zone without violating any transmission constraints.

Once required upgrades and cost allocations are identified, each developer must choose whether to pay for required upgrades to receive ERIS or CRIS rights or withdraw from the study through an iterative process. The number of resources seeking to interconnect and the resulting upgrade costs have increased in recent years. Recent Class Year studies have taken approximately two years to complete, while the Cluster Study is designed to have a timeline of 590 days. During this time, new resources seeking to interconnect that are not part of the study must wait until a new study begins. If the Cluster Study or Class Year Study identifies the need for SDUs, a preliminary estimate of the SDUs' costs is issued and the affected projects may choose to enter an Additional SDU Study which develops final cost allocations.

1. Inefficient Upgrade Project Selection – Class Year 2023

The most recently completed Class Year study was Class Year 2023, which began in January 2023 and was completed in early 2025. Participants requested approximately 15 GW of ERIS and 14 GW of CRIS. The CY23 study identified $2.8 billion in CTOAF and SUF costs for all projects, with individual cost allocations ranging from $0 to $581 per kW of nameplate capacity with an average cost of $207 per kW. The proposed projects were found to be fully deliverable in all areas except Long Island, where an Additional SDU Study was required. [30]

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[29] For additional details on the interconnection process, see NYISO's Transmission Expansion and Interconnection Manual, available here.

[30] See notices to market participants related to Class Year 2023 on NYISO's interconnection website (available here) and Class Year 2024 Additional SDU Study Report (available here).

Table 2 summarizes the results of the CY23 Long Island Additional SDU Study and developers' final decisions. Developers requested 924 MW of CRIS for battery storage projects on Long Island, of which only 317 MW was found to be deliverable. The Additional SDU Study identified over $400 million of upgrades to make the requested projects deliverable. The largest identified SDU was a 138 kV PAR controlled line between Pilgrim and West Bus, which was estimated to have a development time in excess of 8 years and was needed to make the projects in eastern and central Long Island (comprising most of the requested capacity) deliverable.

Table 2: Summary of CY23 Preliminary SDUs

Area	Queue #	Type	Requested CRIS MW (ICAP)	Deliverable CRIS MW (ICAP)	SDU $ per kW UCAP	Final Decision
Entered Additional SDU Study						
LI East	Q825	Storage	65	26	1,170	Withdraw from Class Year
LI East	Q957	Storage	77	33	841	Withdraw from Class Year
LI East	Q971	Storage	125	36	842	Accept 55 MW partial CRIS (44%)
LI East	Q1012	Storage	77	23	842	Withdraw from Class Year
LI East	Q1117	Storage	70	20	842	Accept 30 MW partial CRIS (43%)
LI East	Q1255	Storage	80	30	962	Accept 40 MW partial CRIS (50%)
LI East	Q1256	Storage	100	30	842	Withdraw from Class Year
LI East	Q1257	Storage	60	18	842	Accept 27 MW partial CRIS (44%)
LI Central	Q1123	Storage	150	55	842	Accept 89 MW partial CRIS (59%)
LI West	Q1254	Storage	40	0	199	Accept SDU cost allocation
Did Not Enter Additional SDU Study						
LI East	Q1159	Storage	50	17	701	Withdraw from Class Year
LI East	PAM-2020-77593	Storage	10	10	0	Accept SDU cost allocation
LI Central	Q1113	Storage	20	20	0	Accept SDU cost allocation

SDU cost allocations for projects in eastern and central Long Island averaged $880 per kW of expected UCAP (based on current capacity accreditation factors (CAFs) for battery storage). The SDU costs for the associated upgrades are likely prohibitive for any developer given that $880 per kW of UCAP is close to the net present value of 20 years of capacity payments for a Long Island generator, even if the capacity price equals levelized cost of new entry for Long Island. Accordingly, all the affected developers in eastern and central Long Island withdrew entirely or accepted a partially deliverable amount of CRIS that did not require further upgrades.

The CY23 results highlight a significant concern with the deliverability test process – that the deliverability rules may require new resources seeking CRIS to fund inefficient SDUs or not move forward with the investment. This can happen when it would be more efficient to:

- Retire existing resources in the pocket – This happens when new resources would be less costly than nearby existing resources and the cost of the SDU exceeds the value of the associated transmission facilities.

- Disaggregate the Capacity Region – This happens when the efficient price level in the export-constrained area would be non-zero and the new resources would be profitable selling capacity at the reduced price level there.

While projects outside of Long Island were found to be deliverable in CY23, entry of new resources may result in new deliverability bottlenecks in future studies. For example, the CY23 study found that the deliverability headroom on the UPNY-CONED interface (between zones G and H) declined to about 200 MW when all CY23 projects were included, down from over 900 MW in Class Year 2021. Other recent Class Year studies have identified SDUs in other areas such as Staten Island that resulted in developers withdrawing or accepting only partial CRIS.

Given the scale of new capacity planned in New York, the deliverability evaluations must be accurate and should not be an inefficient barrier to new investment. In general, requiring new entrants to fund transmission upgrades is inefficient when the cost of the transmission upgrade exceeds its value (based on the difference between the present value of future capacity prices and the levelized net cost of new entry). In addition, we have concerns with several specific aspects of the deliverability framework that are discussed in the remainder of this section.

2. Concerns with Deliverability Framework – Deterministic Methodology

The DIS was designed to ensure that new resources will be deliverable throughout their Capacity Region. However, it uses a test methodology that is poorly aligned with the resource adequacy analyses that are the primary basis for determining reliability needs and capacity prices in each region. As penetration of renewables and storage grows, capacity will be valuable in a broader array of hours when load is high or intermittent output is low. As we discuss below, the deterministic deliverability methodology will tend to make inaccurate determinations and may consequently allocate excessively large SDUs to project developers.

The deliverability test models the power flows model in a single summer peak hour. "Import" and "Export" areas are defined within each capacity zone, separated by internal transmission constraints. The test increases the output of the generators in the Export zone (including Class Year projects) to its maximum level based on their average availability (accounting for forced outages and average summer output for renewable resources). If this cannot be done without causing a transmission constraint to be violated, capacity in that area is deemed not deliverable.

This deterministic test makes a single determination for the projects based on a hypothetical dispatch that is often very unrealistic. In reality, resources in the export area may be deliverable under some conditions but not others. Load levels, forced outages, intermittent output levels (including behind-the-meter solar), transmission flows from neighboring regions, and other factors are variable and have a large impact on deliverability. A comprehensive evaluation of a resource's capacity value would consider a wide range of conditions using probabilistic methods to assess how likely the resource is to be available and deliverable during the tightest conditions.

The findings of the deliverability study are most likely to be inaccurate when examining intermittent resources and storage, because their highly variable and even complementary nature is poorly represented by the deterministic approach. For example:

- Offshore wind is assumed to have an output level of approximately 35 percent of nameplate in deliverability studies (based on its average capacity factor in peak load hours), but the most critical hours for reliability are likely to occur when wind output is much lower as wind penetration rises.
- Battery storage is assumed to discharge at its maximum output level, while in reality batteries may support reliability by discharging at a reduced level over a longer period or by discharging more when wind output falls.

Since the deliverability study methodology does not consider the dynamics of these resource types, it is likely to assign excessive SDU costs. The impact of this is already being felt as hundreds of MWs of battery storage in eastern and central Long Island (where there is also significant offshore wind development) have been found undeliverable.[31]

3. Concerns with Deliverability Framework – Assumptions on Resource Mix

The Class Year SDU Study models deliverability in a particular future year. For example, the CY21 study (developed in 2021 and 2022) modeled conditions in 2026. As a result, outcomes of the SDU Study are affected by key assumptions regarding future conditions, including:

- *Stalled Projects from Prior CYs* – New resources that obtained CRIS in a prior Class Year study are modeled in service, but many projects that complete a Class Year are never built. For example, the 500 MW Poseidon HVDC project in Central Long Island completed CY 2015 and was modeled in service in the CY 2019 study. It affected the determination of SDUs even though it later exited the interconnection queue. Over 14 GW of nameplate capacity (as of March 2025) in NYISO's queue have completed the Class Year process but not have reached a final investment decision; such projects could contribute to deliverability bottlenecks in future studies even if they are never built. The newly approved Cluster Study approach may reduce the number of stalled projects by increasing the costs for a given project to retain its interconnection position.
- *Anticipated Retirements* – All existing resources are modeled in service unless they have already submitted retirement notices to NYISO or are otherwise treated as firm retirements.[32] Subsequent economic retirement of projects may cause headroom to change in the future. Consequently, a new project might have an incentive to delay entry until after such a retirement occurs to avoid SDUs.
- *Under-utilized CRIS Rights* – Existing resources are modeled based on their CRIS rights. For some resources, DMNC-based capability values are much lower than CRIS. As a

[31] See Appendix Section VI.J for an analysis of NYISO's methodology for determining the assumed output level of intermittent and storage resources in the deliverability study.

[32] Projects that notify NYISO of their intent to transfer their CRIS rights to a Class Year project at the same location will be modeled as retired when the new project is studied.

result, more capacity can be modeled in the deliverability test than can be produced in the resource adequacy model or in actual operations.

- *Stale Assumptions as IPR Penetration Rises* – The calculation of intermittent resources' average availability relies on the GE-MARS model used in the most recently available IRM study at the time of the deliverability study. Since this model will not include the Class Year projects, the average availability calculation may be inaccurate.
- *Failure to Evaluate Winter Conditions* – Winter reliability needs are increasingly important and NYISO's reliability risks may increasingly occur in the winter. CRIS values established under the current framework will become more inaccurate as the system evolves. This can produce inappropriately high SDUs for solar generation and other resources with higher summer availability.

These issues can lead to deliverability being: a) underestimated, leading to inflated or unnecessary SDUs that can inhibit investment, or b) overestimated, leading to CRIS rights being granted to resources that are not fully deliverable, which may require NYISO to increase future locational capacity requirements. Additionally, problems arise because CRIS rights allow a resource to be treated as fully deliverable in perpetuity, regardless of changes in conditions that might make the project more or less deliverable over time. Finally, even when the deliverability determinations are accurate, the resulting SDUs may not be economically efficient – in other words, the cost of the upgrades may be substantially higher than their congestion benefits, which serves as an inefficient barrier to investment in new resources.

The problems with the deliverability framework could be addressed by simply compensating capacity suppliers based on their ability to support system reliability in each year. One way to do this is to define more disaggregated zones that would allow interzonal deliverability constraints to be priced in the capacity market. We continue to recommend this change in Section VIII.C, which would be a substantial improvement over the deliverability framework.

4. Concerns with Deliverability Framework – Favors Existing Over New Resources

NYISO's market products are generally designed to provide the same compensation to similarly situated resources, regardless of which resource entered first. This is consistent with well-functioning competitive markets for most products. However, the deliverability rules in the capacity market discriminate in favor of existing resources by imposing SDUs on new resources.

For example, recent Class Year Studies have repeatedly found projects seeking CRIS rights on Staten Island to not be deliverable. These projects were allocated SDUs costing hundreds of millions of dollars, which no developer has agreed to pay. However, existing resources in Staten Island earn the New York City capacity price even if bottlenecks prevent their capacity from being fully delivered to the rest of the zone. This is a barrier to new resources that prevents them from competing with incumbent resources in export-constrained areas such as Staten Island.[33]

In an efficient market, entry of new capacity to a constrained area would result in a uniform low price for all resources in that area, putting pressure on higher-cost resources to retire. This is the case in NYISO's energy market where entry to a bottlenecked area will reduce LBMPs. This also occurs between zones in the capacity market where surplus capacity in a zone causes its price to fall relative to other zones. However, it is prevented from occurring within capacity zones by the deliverability framework and the lack of granular capacity pricing.

5. Deliverability Framework Conclusions

The NYISO's current rules are poorly suited to address deliverability in the capacity market because: (1) its deterministic deliverability test does not accurately identify deliverability concerns or efficient transmission upgrades; (2) it establishes permanent CRIS rights that do not reflect changes in deliverability as the system evolves over time, and (3) it discriminates against new resources in favor of existing resources. These problems are increasingly likely to impede efficient new investment as recent Class Year studies have allocated large SDUs to projects seeking CRIS rights. To address these concerns, we recommend:

- *Defining a comprehensive set of granular zones in the capacity market*.[34] This would effectively shrink the size of the capacity zones in which new resources seeking CRIS rights would have to be deliverable. This would greatly reduce the number of intrazonal constraints triggering SDUs and allow the capacity market to price many more interzonal constraints. This would improve incentives for both new and existing resources.
- *Establishing financial capacity transfer rights (FCTRs)* to be allocated to developers or others that wish to pay for network upgrades that would alleviate interzonal transmission bottlenecks. This would allow market participants who pay for upgrades to retain the economic value of those upgrades in the capacity market,[35] and provide a hedge against the risk of binding transmission constraints in the capacity market.[36]

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33 Projects may avoid a deliverability study or reduce the exposure to SDUs by acquiring the CRIS rights of an existing resource. NYISO revised its CRIS transfer rules in 2023 to make this process more flexible. (See Jan. 25, 2023 presentation to Management Committee "CRIS Expiration Evaluation", available here.) However, holders of existing CRIS rights will value them based on their ongoing capacity profits even when it is efficient to retire, so new resources facing costly SDUs will continue to face inefficient barriers to entry.

34 See Recommendation 2022-4 in Section XII and Section VIII.C.

35 See Recommendation 2012-1c in Section XII. Section VIII.C outlines an approach to calculating financial payments (or charges) to projects that affect transfer capability which is called the Capacity Constraint Pricing (CCP) Charge/Credit.

36 For example, consider an investor that owns a generator in an export-constrained zone and FCTRs on the interface between that zone and another zone. When the zone is export-constrained, capacity payments to generators in the zone would fall but payments to the holders of FCTRs would rise.

B. Transmission Planning Processes

NYISO's centralized transmission planning processes are designed to identify and fund transmission investments that are most cost-effective for satisfying reliability needs, achieving public policy goals, and/or reducing congestion. These planning processes are important because the markets generally do not provide efficient incentives for merchant transmission investment.

Projects selected in the planning processes are funded through regulated cost recovery rather than market revenues. Selecting inefficient projects can raise ratepayer costs and crowd out more economic merchant solutions (transmission and non-transmission). Hence, planning processes should be designed to select the most efficient projects by utilizing rigorous cost-benefit analyses. Such analyses should include the value of the capacity, energy, and ancillary services the projects affect. This subsection provides an overview of the transmission planning processes and discusses improvements that will result in more efficient transmission investment.

1. Overview of NYISO's Transmission Planning Process

NYISO performs centralized transmission planning through the Comprehensive System Planning process (CSPP).[37] The CSPP consists of the following processes:

- The *Reliability Planning Process* identifies reliability needs in the short and long term and solicits solutions for needs for Bulk Power Transmission Facilities (BPTFs);
- The *Economic Planning Process* studies potential future congestion and includes a phase to evaluate projects proposed by developers to relieve congestion, but no transmission has ever been built through this process. The main product of this process is the System & Resource Outlook ("the Outlook") that assesses future congestion and is used as the basis for evaluations of projects in other processes, such as the PPTPP.
- The *Public Policy Transmission Planning Process (PPTPP)* solicits, evaluates and selects projects designed to address policy-driven needs identified by the NY State Public Service Commission, such as integration of renewable energy.

In addition to these NYISO planning mechanisms, transmission planning carried out by utilities and state agencies affects on the wholesale markets. New York's electric utilities plan investments in lower-voltage local transmission and distribution that are needed to accommodate clean energy goals through the Coordinated Grid Planning Process.[38] The state also has a process to identify "Priority Transmission Projects" regarded as needing rapid approval to comply with state policy mandates, to be built by the New York Power Authority.[39] In recent

[37] For more information about the CSPP, see here.

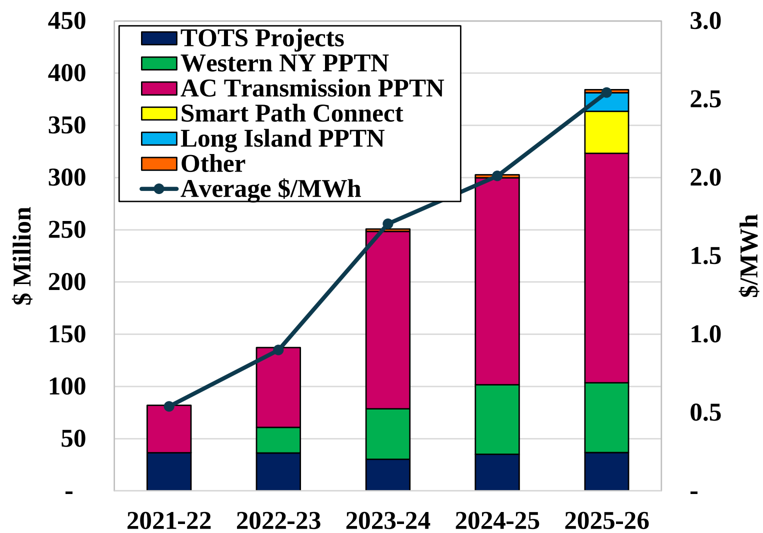
[38] Local transmission generally refers to facilities that serve local load or operate at less than 200 kV. See NYPSC Case 20-E-0197.

[39] For example, see October 15, 2020 Order in NYPSC Case 20-E-0197, identifying the "Northern New York" bulk transmission project as a Priority Transmission Project.

years, transmission investment has primarily taken place through the PPTPP. NYISO has identified solutions for three Public Policy Transmission Needs (PPTN): the Western New York, the AC Transmission, and the Long Island Offshore Wind Export PPTNs. Currently, NYISO is conducting a study for the New York City Offshore Wind PPTN.

The costs of transmission projects selected through NYISO's planning processes are allocated to loads under NYISO's OATT rate schedules. Figure 13 shows the total annual cost recovery quantities and approximate cost per MWh (averaged across all NYCA load) for transmission projects recovered through NYISO rate schedules in recent years. In practice, costs allocated to customers in each transmission owner area or load zone are not always proportional to load and vary by project. The costs of transmission projects recovered through NYISO rate schedules have increased in recent years and will continue to rise, driven by public policy projects. This trend may increase the extent to which incentives for generators and loads are driven by regulated rate structures and decrease the relative significance of LBMP congestion and locational capacity prices over time. The embedded costs of transmission owners' network that are not planned by NYISO are also recovered from NYISO market participants under the Transmission Service Charge (TSC) and NYPA Transmission Adjustment Charge (NTAC). In 2024, the TSC and NTAC averaged $8.5 per MWh systemwide, with significant variation across transmission owner areas.

Figure 13: NYISO Regulated Transmission Costs



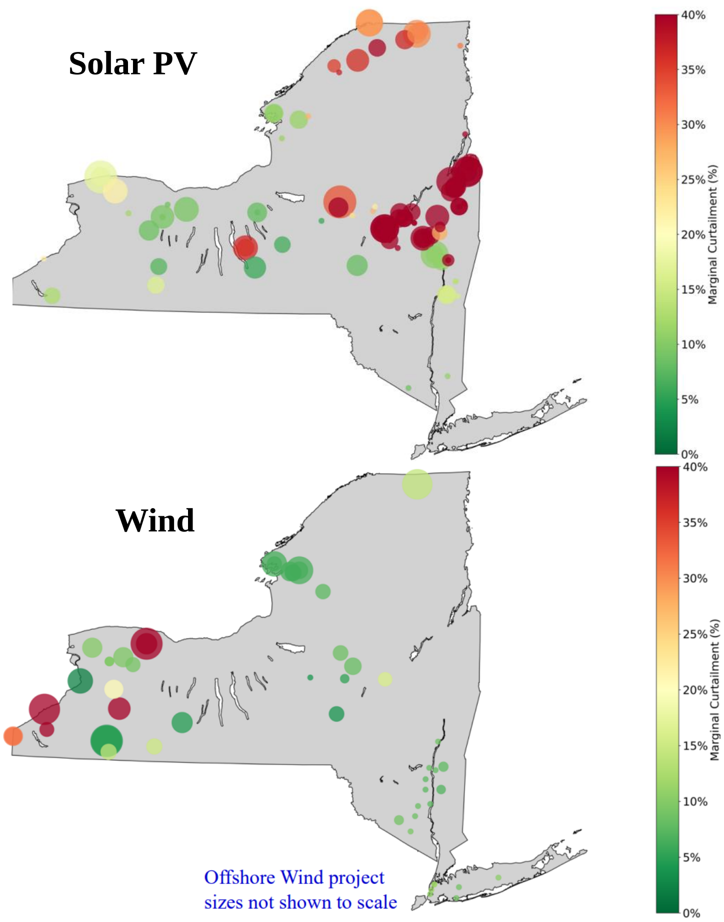
2. Improvements to Transmission Planning Processes

Transmission planning has major impacts on prices and incentives in the NYISO markets. Efficient planning decisions can enable investment in low-cost generation resources and reduce the amount of capacity needed in higher-cost areas. However, inefficient planning decisions can undermine market incentives to invest in non-transmission projects (e.g., storage or generation) that provide similar benefits at lower cost. This subsection discusses how NYISO's transmission planning can be made more efficient using wholesale market principles.

Assumptions Used in Planning Models

Assumptions used in long-term planning models such as NYISO's Outlook affect the location and magnitude of apparent transmission needs. The Outlook models are also used in the PPTN process to evaluate proposed projects' benefits. Hence, the assumptions and techniques used in the Outlook models have major implications for the NYISO markets because they affect which transmission needs are identified and which solutions are selected.

Figure 14: Marginal Curtailment Rates of Renewables in 2023 Outlook 2035 Policy High



Our reviews of recently completed planning studies provide detailed discussions of NYISO's planning models and evaluation methods.[40] Beginning with the initial 2021 Outlook, NYISO improved upon previous studies by using a capacity expansion model to develop a forecast of future resource mix changes needed to efficiently comply with state clean energy mandates. The 2023 Outlook (completed in 2024) made further improvements including usage of a chronological set of representative days in the capacity expansion model and improved representation of battery storage and dispatchable emissions free resource (DEFR) options. However, we have also highlighted potential areas for improvement in the planning study models. For example, Figure 14 shows marginal curtailment rates of solar PV and wind projects built to meet state lean energy targets in the 2023 Outlook's 2035 Policy High Load scenario. Due to local and bulk transmission constraints, solar and wind in some locations are curtailed a large percentage of the time while other locations have relatively low marginal curtailment rates. This suggests that targeting renewable additions to more deliverable areas or technologies (as NYISO market prices would tend to encourage) could potentially result in lower overall curtailment or a different set of transmission constraints being identified as problematic.

40 See MMU Review of 2021-2040 System & Resource Outlook, August 2022, available here and MMU Evaluation of the Long Island Offshore Wind Export PPTP Report, May 2023, available here.

In order to provide the most realistic and informative results to planners and market participants, we recommend the following improvements in future planning studies:

- Perform an 'optimized' production cost model sensitivity case in which renewable capacity in locations with high marginal rates of curtailment is relocated to locations with lower marginal rates of curtailment;
- Model realistic local capacity requirements driven by changes in the resource mix and transmission network;
- Model procurement of ancillary services in production cost models, considering how future needs will be driven by resource mix changes;
- Improve the siting and dispatch pattern of storage investments in MAPS to more realistically minimize renewable curtailment based on market incentives;
- Represent drivers of winter risk including fuel unavailability in the capacity expansion model; and
- Consider transmission outages and day-ahead net load forecast error when estimating production cost savings.

Valuation of Transmission Projects Using Wholesale Market Prices

Transmission projects' benefits should be evaluated by estimating the revenue that a non-regulated resource providing comparable benefits would receive in the NYISO markets. Such an approach would help to make clear when a regulated or non-regulated project would be more cost-effective. It would also support selection of the most efficiently-sized transmission projects by considering the marginal value of their benefits.

By contrast, recent solicitations have been evaluated using methods that do not reveal the project's marginal value in the NYISO markets, making it challenging to assess which projects are most competitive. Transmission benefits can be calculated based on wholesale market prices as follows:[41]

- <u>Energy benefits</u> – The market value of the congestion relief provided by the project. This is calculated considering the project's impact on constrained transmission elements in each hour (which may or may not be project facilities), given the flows and the shadow prices of congested elements.
- <u>Capacity benefits</u> – The market value of avoided generation investment that would be needed without the project. This is calculated using the marginal reliability impact (MRI) of the project facilities, the increase in transfer capability they provide, and the Net Cost of New Entry ("Net CONE") used to determine capacity prices. This results in valuation comparable to revenues received by capacity sellers.

[41] See also February 21, 2023 comments of Potomac Economics in NYPSC Case 22-E-0633.

- Implied Net REC – For solicitations that explicitly target renewable energy integration, the efficiency of transmission proposals can be compared to other alternatives by calculating an Implied Net REC. This is calculated as the project's levelized cost net of energy and capacity benefits, divided by the incremental reduction in annual renewable curtailment it provides ("renewable deliverability impact").[42]

These calculation techniques are based on evaluating conditions in a "project case" (which assumes the transmission project is in-service), while the NYISO calculates benefits by comparing conditions in the project case to a "base case" (in which the project is not included). One key feature of estimating benefits based on the project case alone is that it is simpler and facilitates accounting for other changes in the assumed resource mix.

Transmission Planning Conclusions

Using the principles of efficient market incentives in planning models and when evaluating proposed projects will allow the NYISO to select more efficient projects and help to level the playing field between regulated transmission and non-regulated investments. Hence, we recommend the following:[43]

a) Update the methodology of the Outlook study to address the modeling assumption and methodology improvements discussed in this section;

b) Evaluate economic and PPTN projects using a project case that considers changes to the resource mix resulting from the Project's inclusion; and

c) Estimate transmission project benefits based on their NYISO market value.

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[42] For renewable and storage projects, the renewable deliverability impact is the annual MWh of energy an incremental MW of the resource would provide (or save from being curtailed) without causing curtailment of other resources. For transmission projects, the renewable deliverability impact is the annual MWh of incremental transfers of renewable energy across the project facilities and other lines whose loading the project relieves, measured during hours of curtailment due to transmission constraints. This can be calculated using generation shift factors of renewable resources and flows over the project facilities.

[43] See Recommendation 2022-3 in Section I.

V. DAY-AHEAD MARKET PERFORMANCE

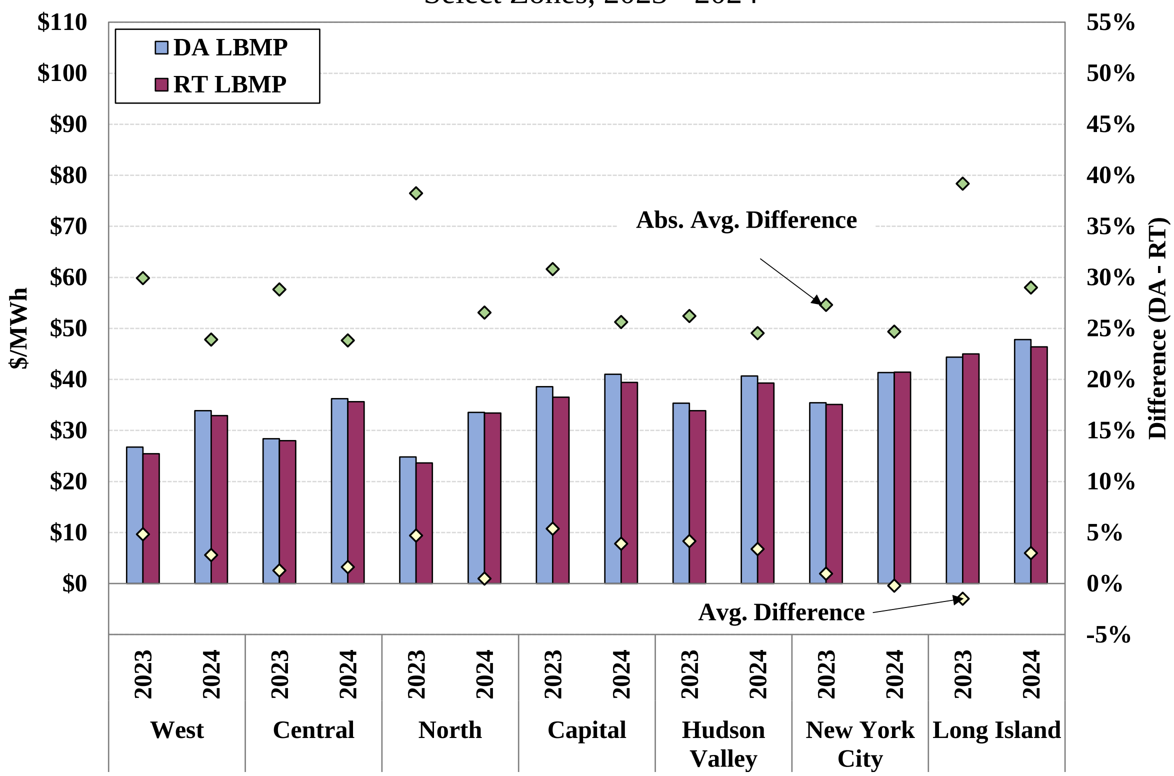
The day-ahead market enables firms to make forward purchases and sales of power for delivery in real-time the next day. This allows participants to hedge their portfolios and manage real-time price volatility. In a well-functioning market, the day-ahead and real-time prices will not diverge systematically because participants will adjust their purchases and sales to arbitrage such differences. Price convergence is desirable also because it promotes the efficient commitment of generation, procurement of natural gas, and scheduling of external transactions. In this section, we evaluate the convergence of day-ahead and real-time energy prices (in subsection A), day-ahead scheduling patterns (in subsection B), and virtual trading (in subsection C).

A. Day-Ahead to Real-Time Price Convergence

The following figure evaluates price convergence at the zonal level by reporting the percentage difference between the average day-ahead price and the average real-time price in select zones. The figure also reports the average absolute value of the difference between hourly day-ahead and real-time prices. These statistics are shown on an annual basis.[44]

Figure 15: Price Convergence between Day-Ahead and Real-Time Markets

Select Zones, 2023 - 2024



44 Section I.H in the Appendix evaluates the monthly variations of average day-ahead and real-time energy.

Day-ahead prices in 2024 were higher on average than real-time prices in all regions except New York City. In a competitive market, day-ahead prices typically exhibit a small premium over real-time prices, while real-time prices are often higher during volatile periods. In 2024, we observed low real-time volatility and persistently low gas prices and few transmission outages affecting the Central East Interface. Real-time prices were higher in July in most regions when peak load conditions occurred and reserve shortages were most common. Day-ahead price premiums were largest in January when gas price volatility was highest.

Long Island remains more susceptible to real-time price premiums than other areas for several reasons. First, the generation fleet is older and non-quick start units are relatively slow-ramping steam units, contributing to more real-time price volatility in the morning and evening ramping hours. Second, the local gas distribution company provides less flexibility to generators that increase or decrease gas schedules intraday, and Long Island is more reliant on oil-fired generation. Third, Long Island is less connected to other areas through the high voltage transmission system.

The North zone has: (a) substantial amounts of intermittent renewable generation, (b) interfaces with Quebec that convey large amounts of imports that are low-cost or inflexible during real-time operations, and (c) volatile loop flows passing through from neighboring systems. These factors lead to volatile congestion pricing on transmission bottlenecks from north to central New York. However, given persistent draught conditions in Quebec in recent years, imports from Quebec have fallen, which has ameliorated congestion on this path.

New York City congestion increased in 2024 and volatility was higher in real-time largely because of tighter supply conditions after the retirement of several hundred megawatts of peaking generation resources. Transmission outages, coupled with increased reliance on old, slow-ramping steam turbines which are more prone to unforeseen outages than newer resources, drove real-time premiums in the city during 2024.

B. Day-Ahead Load Scheduling

Under-scheduling load generally leads to lower day-ahead prices, while over-scheduling tends to raise day-ahead prices above those in real-time. Figure 16 shows the average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percentage of real-time load in 2023 and 2024 for several regions.

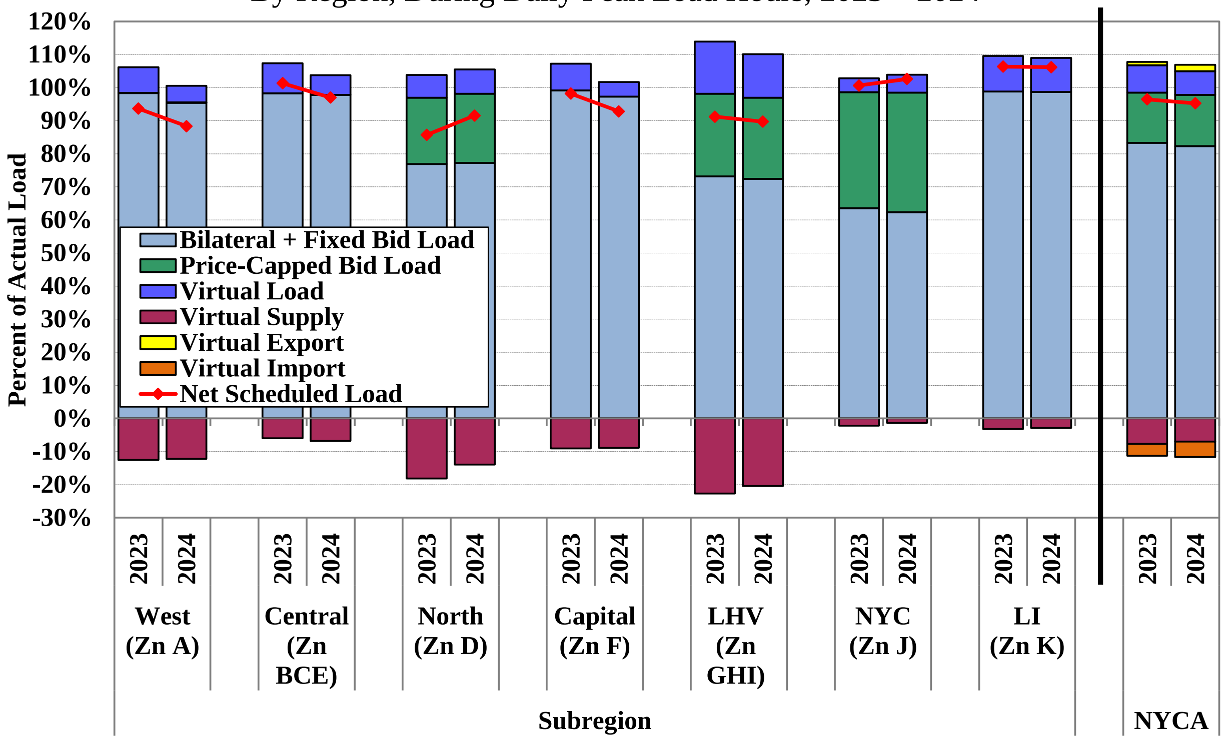
Overall, net scheduled load in the day-ahead market was approximately 95 percent of actual NYCA load during daily peak load hours in 2024, slightly lower than in 2023. This pattern of net under-scheduling at the NYCA level is driven by several factors that reduce the incidence and severity of high real-time prices, including:

- The large quantity of available offline peaking generation and available import capability that can respond to unexpected real-time events,

- Out-of-market actions (i.e., SRE commitments and OOM dispatch) that bring online additional energy and reserves after the day-ahead market, and
- The tendency for renewable generators to under-schedule in the day-ahead market.

Figure 16: Day-Ahead Load Scheduling versus Actual Load

By Region, During Daily Peak Load Hours, 2023 – 2024



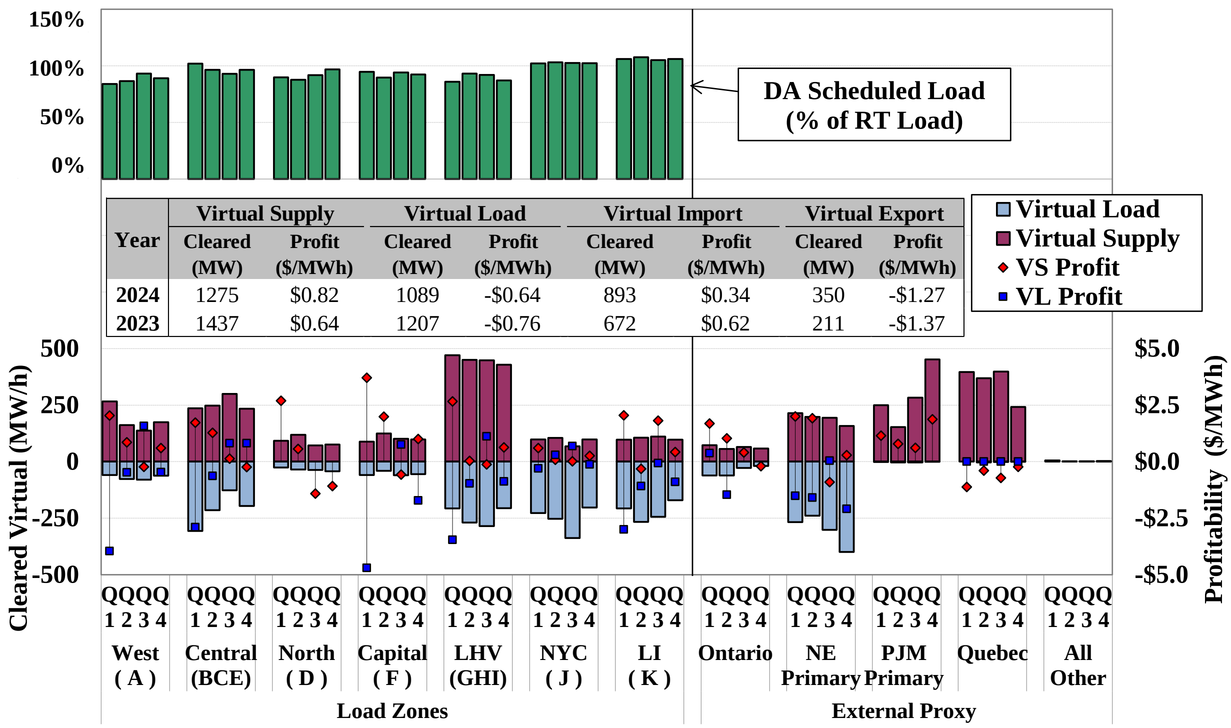
Average net load scheduling tends to be higher where volatile real-time congestion leads to very high (rather than low) real-time prices. Historically, this was the case in the West zone where net load scheduling was high because the majority of load was located just downstream of transmission bottlenecks near Niagara. However, completion of the Empire State Line in June 2022 has relieved most of this congestion and the related real-time price volatility. Consequently, average day-ahead net scheduled load in the West zone has steadily fallen from 109 percent in 2021 to 88 percent in 2024.

Net scheduled load fell in most regions, although New York City saw an increased percentage of net load scheduled day-ahead from 2023. Higher day-ahead net load scheduling generally helps increase commitment of resources in these areas. In New York City, day-ahead net scheduled load rose to average 103 percent in 2024, which was likely driven by more frequent severe localized congestion patterns following the exit from the market of approximately 800 MW of peaking capacity between the summers of 2022 and 2023.

C. Virtual Trading

Virtual trading helps align day-ahead prices with real-time prices, which is particularly beneficial when systematic inconsistencies between day-ahead and real-time markets would otherwise cause the prices to diverge. Such price divergence ultimately raises costs by undermining the efficiency of the resource commitments in the day-ahead market. Figure 17 summarizes virtual trading by location in 2024, including internal zones and external proxy buses.[45]

Figure 17: Virtual Trading Activity
by Region by Quarter, During All Hours, 2024



Year	Virtual Supply Cleared (MW)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW)	Virtual Export Profit ($/MWh)
2024	1275	$0.82	1089	-$0.64	893	$0.34	350	-$1.27
2023	1437	$0.64	1207	-$0.76	672	$0.62	211	-$1.37

The profits and losses of virtual load and supply have varied over time, reflecting the difficulty of predicting volatile real-time prices. Virtual traders netted a profit of approximately $1.2 million in 2023 and $1.8 million in 2024. Virtual profits at internal zones in 2024 totaled $3 million, while virtual trading at interfaces lost $1.2 million. The overall average rate of virtual profitability remained slightly positive at $0.06 per MWh. In general, low virtual profitability indicates that the markets are relatively well-arbitraged, while virtual losses are unlikely to persist for a significant period.

45 See Figure A-37 in the Appendix for a detailed description of the chart. The method used in this report to calculate virtual quantities and profits has changed from past State of the Market reports. Specifically, DA scheduled transactions at the external interfaces that were cut or curtailed by system operators are excluded from the numbers in this report, resulting in higher net profitability numbers for virtual imports and exports.

VI. Market Operations

The purpose of the wholesale market is to coordinate resources efficiently to satisfy demand while maintaining reliability. The day-ahead market should commit the lowest-cost resources necessary to meet expected conditions on the following day, and the real-time market should dispatch the available resources efficiently. Prices should reflect the cost of satisfying demand while maintaining security and reliability. Efficient real-time prices encourage competitive supplier behavior, demand response participation, and investment in new resources and transmission in the most valuable locations. During shortage conditions, real-time prices should reflect the value of foregone supply and incent suppliers to support reliability. Effective system operations are also important, as they significantly affect wholesale market efficiency and costs.

We evaluate six aspects of market operations in this section, focusing on the efficiency of incentives, scheduling, and pricing, particularly during tight operating conditions:

- Market Performance under Shortage Conditions (sub-section A)
- Real-Time Pricing of GTs Bidding Mult-Hour Minimum Run Times (sub-section B)
- Operation of Duct-Firing Capacity (sub-section C)
- Performance of Intermittent Power Resources during Curtailment Events (sub-section D)
- Supplemental Commitment for Reliability (sub-section E)
- Uplift from Bid Production Cost Guarantee (BPCG) payments (sub-section F)

This section discusses several recommendations we have made to enhance pricing efficiency and performance incentives in both the day-ahead and real-time markets.[46] .

A. Market Performance under Shortage Conditions

Prices during shortage conditions are important for providing efficient long-term market signals. Shortages occur when available resources are insufficient to meet the system's need for energy and ancillary services. Efficient shortage pricing rewards suppliers and demand response resources for promptly addressing these shortfalls. This ultimately improves the resource mix by shifting revenues from the capacity market into the energy market, thereby more accurately compensating resources based on their performance. In this subsection, we evaluate real-time market operations and price formation during two primary types of shortage conditions:[47]

46 A comprehensive list of our recommendations is provided in Section I.

47 Emergency demand response deployments are similar to shortage conditions because they occur when NYISO forecasts a reserve deficiency. See Appendix Section VIII.C for our evaluations of demand response deployments in 2024.

- **Operating reserve and regulation shortages** – These occur when the market schedules less than the required level of an ancillary service. The co-optimization of energy and ancillary services ensures that the foregone value of ancillary services is reflected in LBMPs.
- **Transmission shortages** – These occur when modeled power flows exceed transmission constraint limits. During transmission shortages, LBMPs at affected locations are typically set using the Graduated Transmission Demand Curve (GTDC).

1. Operating Reserve and Regulation Shortages

Although regulation shortages remained the most frequent type of ancillary services shortage in 2024, they occurred in fewer than 3 percent of intervals. This marked a continued decline from the 2022 level largely because of increased regulation-capable supply following the entry of new Energy Storage Resources (ESRs). Despite modest increases from 2023 due to higher load levels, operating reserve shortages continued to be relatively infrequent in 2024. System-wide 30-minute reserve shortages were the most common, occurring in approximately 0.6 percent of intervals. Collectively, shortages in regulation and operating reserves increased average LBMPs by 7 to 9 percent in 2024.[48] Thus, ancillary services shortages have a significant impact on investment signals, shifting incentives toward flexible generation.

During operating reserve shortages, real-time prices should accurately reflect the foregone value of reserves, providing adequate incentives to attract resources needed to maintain reliability without resorting to out-of-market actions. This subsection evaluates NYISO's shortage pricing, including the efficiency of the Operating Reserve Demand Curve (ORDC) in reflecting the reliability value of each class of reserves.

ORDC Price Levels in NYISO versus Neighboring Areas

NYISO's ORDCs are relatively low compared to shortage pricing levels in PJM and ISO New England.[49] Figure 18 compares NYISO's shortage pricing incentives with those provided by its neighbors, both of which have shortage pricing in their energy markets that is supplemented by additional "pay-for-performance" settlements in the capacity market.[50] The figure shows that shortage pricing is generally much lower in New York than in the neighboring markets:

- During deep shortages of 30-minute reserves, NYISO shortage pricing, including locational adders, approaches roughly $1,000 per MWh, significantly lower than ISO-NE's current level of approximately $6,700 per MWh. ISO-NE's shortage pricing will

48 See Section V.H in the Appendix for this analysis.

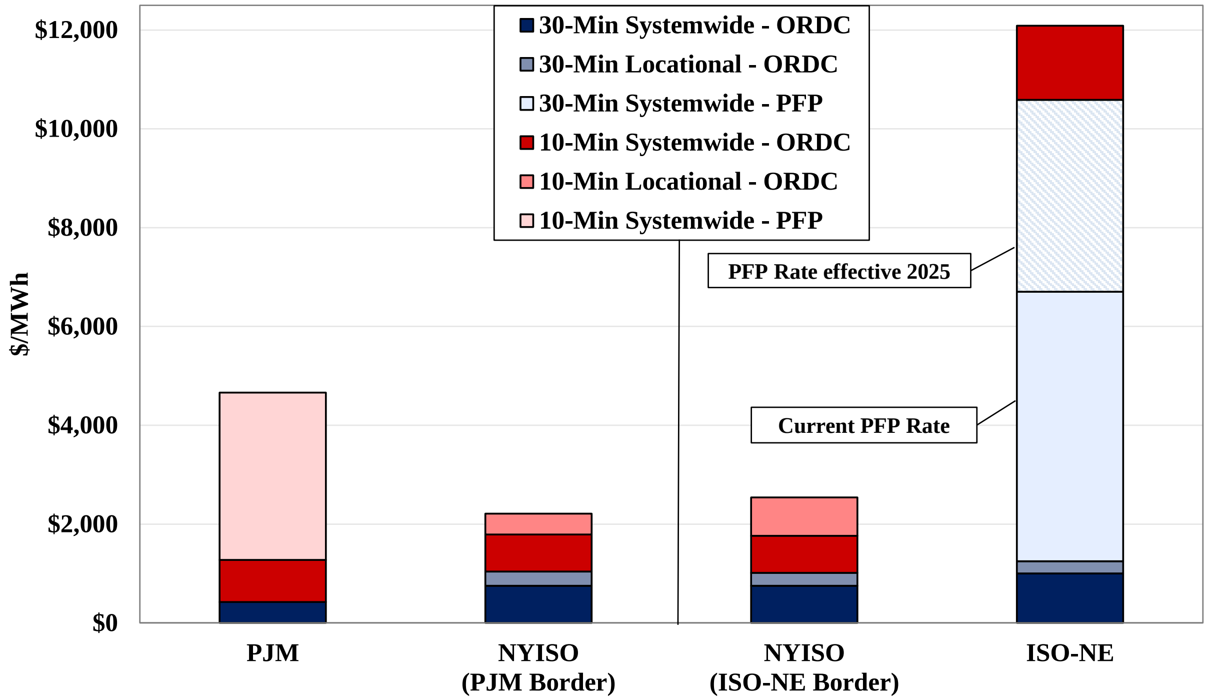
49 ISO New England has Pay For Performance ("PFP") rules, and PJM has Capacity Performance ("CP") rules. These rules provide incentives similar to shortage pricing through adjustments to capacity payments.

50 See Figure A-86 in the Appendix for description of this chart.

further increase to over $10,000 per MWh in June 2025, following the scheduled rise of its Performance Payment Rate from $5,455 to $9,337 per MWh.[51]

- During deep shortages involving multiple 30-minute and 10-minute reserve requirements, NYISO invokes statewide shortage pricing levels that can exceed $2,000 per MWh under severe conditions. However, this remains substantially lower than the current total shortage pricing in neighboring markets – nearly $4,700 per MWh in PJM and over $12,000 per MWh in ISO-NE starting this summer.

Figure 18: Shortage Pricing in NYISO vs. Neighboring Markets



Consequently, when NYISO is in a much less reliable state than PJM or ISO-NE, market participants will have strong incentives to export power from (or reduce imports to) NYISO. This pricing disparity will tend to undermine reliability in New York or necessitate out-of-market actions by NYISO operators to maintain system reliability.

ORDC Price Levels Compared to the Reliability Value of Reserves

In addition to comparing NYISO's shortage pricing with its neighbors, we also evaluate how effectively NYISO's shortage pricing reflects the reliability risks associated with reserve shortages. Shortage pricing is determined by an RTO's ORDC for each class of reserves. Ideally, the ORDC should indicate the marginal reliability value of these reserves, based on the value of being able to serve the load, referred to as the Value of Lost Load (VOLL). As reserve

51 See ISO New England Tariff Section III.13.7.2.

levels fall, the risk of load shedding increases, implying the marginal value of reserves can be estimated as:

Expected Value of Lost Load (EVOLL) = VOLL × Probability of losing load

Based on studies examining the value of reliability, a reasonable estimate of NYISO's VOLL is approximately $30,000 per MWh.[52] The slope of an efficient ORDC depends on how rapidly the probability of losing load increases as operating reserves decreases, which is estimated from the likelihoods of random contingencies and conditions that could arise during a shortage in the NYISO market. To quantify the relationship between available operating reserves and the probability of losing load, we used a Monte Carlo simulation tool that considered random forced generation outages, wind forecast errors, net load forecast errors, and import curtailments by neighboring areas (collectively referred to as "unexpected losses of net supply").[53]

Figure 19: Comparison of MMU Economic ORDC to the Current 10-Minute ORDCs

NYCA Wide 10-Minute Reserves

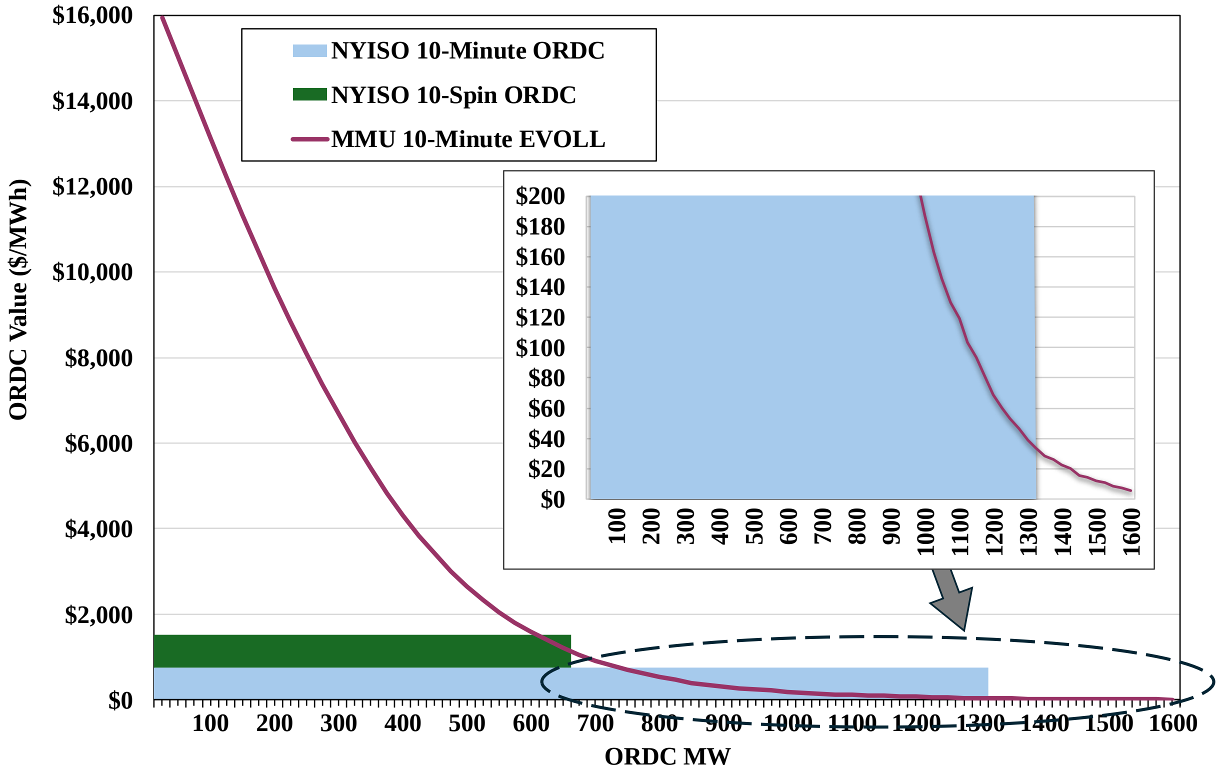


Figure 19 compares our estimates of the EVOLL curve for NYCA-wide 10-minute reserve requirements to the current ORDC utilized in the NYISO market, including both 10-minute spin and 10-minute total reserves that together reflect the total value of 10-minute reserves.

52 See Section V. HH in the Appendix for the mentioned studies.

53 See Section V.H H in the Appendix for the simulation methodology in more details.

This analysis reveals that the current ORDC curves significantly undervalue the marginal reliability value of 10-minute reserves when available 10-minute reserve levels drop below 600 MW. Specifically, the MMU-estimated EVOLL curve rises above $16,000 per MWh when 10-minute reserves are nearly depleted, which is 10 times higher than the current combined ORDC value of $1,525 per MWh for 10-Minute Spin and 10-Minute Total reserves. However, when reserve levels are above 800 MW, the existing 10-minute total ORDC is significantly higher than the estimated marginal reliability value of these reserves.

A comparable analysis of the 30-minute ORDC is discussed in Appendix Section V.H. It shows that the existing 30-minute ORDC in the NYISO market undervalues 30-minute reserves when they are at or below approximately 725 MW. The estimated marginal reliability value at near-depletion is roughly $2,800 per MWh, nearly four times of the $750 per MWh set by the current ORDC.

Finally, the MMU-estimated EVOLL curves extend beyond the existing requirements of 1,310 MW for 10-minute reserves and 2,620 MW for 30-minute reserves. These estimates of the reliability value of holding additional reserves beyond the base requirements support the NYISO's proposal to develop additional longer lead-time reserve products as we have recommended and "uncertainty reserve" products to address uncertainties associated with intermittent resource availability.[54]

ORDC Price Levels – Conclusions

We recommend NYISO revise its current ORDC curves to accomplish two primary objectives:

- **Schedule resources necessary to satisfy reliability criteria without resorting to OOM actions** – Current ORDCs may not provide sufficient incentives, especially given that PJM and ISO New England have adopted unreasonably strong shortage pricing incentives.
- **Achieve better alignment with the estimated reliability value of reserves** – Existing statewide ORDCs undervalue reserves during deep shortages of 10-minute and 30-minute operating reserves when reliability risks are highest.

This recommendation should be a high priority because the demand for resources to respond to emergency conditions in real-time will become increasingly important.[55] The large-scale entry of intermittent renewables will significantly increase net load forecast uncertainty and, consequently, the estimated reliability value of reserves. Implementing this recommendation will improve incentives for generation and load flexibility. Any cost increase associated with higher ORDCs would be offset by corresponding reductions in capacity market demand curves.

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[54] See Recommendation 2021-1. Also see presentation to the Management Committee, "*Balancing Intermittency*", October 31, 2024.

[55] See Recommendation 2017-2.

2. Transmission Shortages

It is crucial for the market to establish efficient prices during transmission shortages, accurately reflecting their severity and properly valuing the effects of transmission bottlenecks across the system. Most transmission shortages are minor and short-lived, posing no significant threat to security or reliability. This is largely because NYISO uses a Constraint Reliability Margin (CRM) of 10 to 100 MW, which provides a buffer between modeled flows and transmission limits for each facility. This buffer ensures that transient differences between schedules and actual output do not lead to violations of transmission security criteria.[56] To reflect the severity of shortages, NYISO uses a Graduated Transmission Demand Curve (GTDC), setting moderately high prices during slight shortages, escalating as the shortage grows more severe.[57]

In November 2023, NYISO implemented *Constraint Specific Transmission Shortage Pricing*, which aligns the MW steps on the GTDC with each facility's CRM.[58] This enhancement improved the alignment between shadow prices and the severity of congestion. Additionally, most internal facilities previously assigned a zero-value CRM now use a new two-step GTDC with a 5-MW CRM. This adjustment largely eliminated the use of constraint relaxation in 2024, which previously occurred in 4 to 5 percent of all transmission shortages. In 2024, transmission shortages occurred in more than 9 percent of all 5-minute market intervals, higher than the 5 percent in 2023, driven largely by the enhancements made in the GTDC.

Despite these improvements, we have identified an ongoing issue that undermines pricing by causing the market software to not recognize real-time transmission shortages. Specifically, this is caused by NYISO's "offline GT pricing," which treats an offline GT being dispatchable in five minutes even though it cannot realistically start that quickly. This inefficiently depresses constraint shadow prices and associated congestion when constraints are violated. It also leads to significant discrepancies between modeled and actual flows, reducing the effectiveness of the real-time market models in maintaining transmission security, particularly in areas that rely more on peaking units, such as Long Island. To secure facilities when there are differences between modeled and actual flows, NYISO may employ larger CRMs on particular constraints, such as the 345 kV lines from upstate New York to Long Island.

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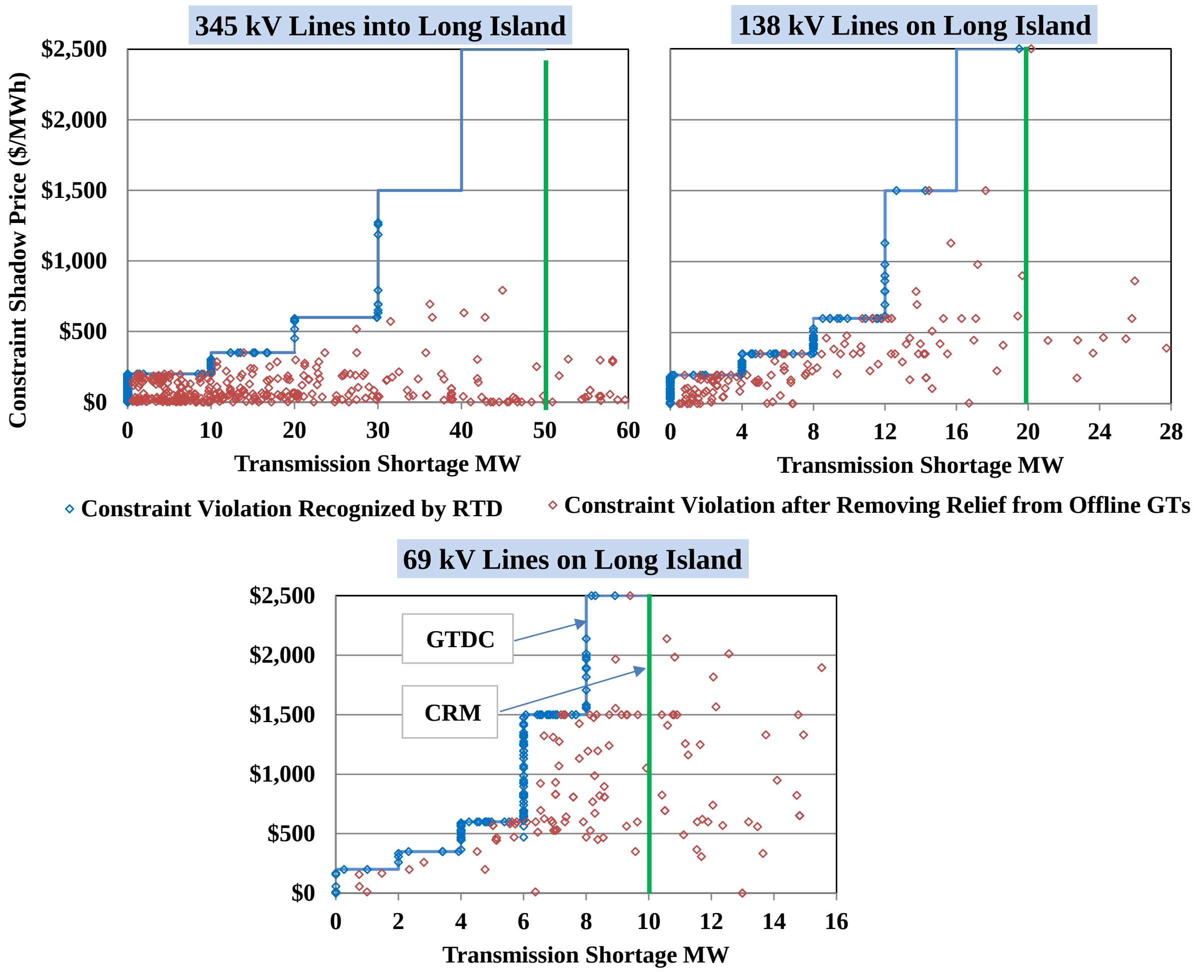
56 A default CRM value of 10 MW is used for 69 kV and 115 kV constraints, while a default CRM value of 20 MW is used for most facilities at higher voltage levels. NYISO may adjust the CRM for an individual facility based on operating experience as necessary to maintain security.

57 Until November 14, 2023, most transmission constraints used a GTDC with a 5-MW step at $350/MWh and a 15-MW step at $1,175/MWh. See Figure 20.

58 Since November 14, 2023, most transmission constraints use a GTDC with five steps of equal length at: $200/MWh, $350/MWh, $600/MWh, $1,500/MWh, and $2,500/MWh. Each step is one-fifth of the CRM in length. Constraint violations larger than the CRM use a GTDC price level of $4,000/MWh.

Figure 20 shows our analysis of Long Island transmission facilities, comparing the magnitude of transmission constraint violations calculated by market software (represented by the blue points), which assumes offline GTs can generate output, with the actual constraint violations recognizing that offline GTs remain offline and produce no output (represented by red points).[59]

Figure 20: Transmission Constraint Shadow Prices and Violations
With and Without "Relief" from Offline GTs, 2024



Most of the GTs that are treated by NYISO's market software as capable of responding to a 5-minute dispatch instruction while offline are located in Long Island. This "offline GT pricing" practice may lead NYISO to reduce modeled transfer limits, thereby constraining transmission flows at artificially low levels in areas that rely more on peaking units such as Long Island. Consequently, this leads to unnecessary generation dispatch and inflated production costs during most periods. Given these inefficiencies, we recommend that NYISO eliminate offline fast-start pricing.[60]

59 See Figure A-90 in the Appendix for description of the chart.

60 See Recommendation 2020-2.

B. Real-Time Pricing of Gas Turbines Bidding Multi-Hour Minimum Run Time

Gas turbines run more frequently under tight conditions, making it particularly important to establish efficient real-time prices that incent resources to be flexible. Under existing fast-start pricing rules, real-time prices include the as-offered deployment costs of fast-start units, including start-up, incremental energy, and minimum generation costs.

However, fast-start units with minimum run time offers exceeding one hour are currently excluded from fast-start pricing eligibility. Specifically, the real-time market software (including RTC and RTD) and settlement rules ignore these units' actual minimum run time offers, deeming them to have a one-hour minimum run time whenever they submit economic real-time offers. Yet, despite being treated the same (for scheduling purposes) as units offering a one-hour minimum run time, these units are not eligible to set prices. This prevents LBMPs from accurately reflecting the true costs of maintaining reliability when these gas turbines are needed.

Figure 21: Prices During Commitments of GTs Offering Multi-Hour Min Run Times
2022 - 2024

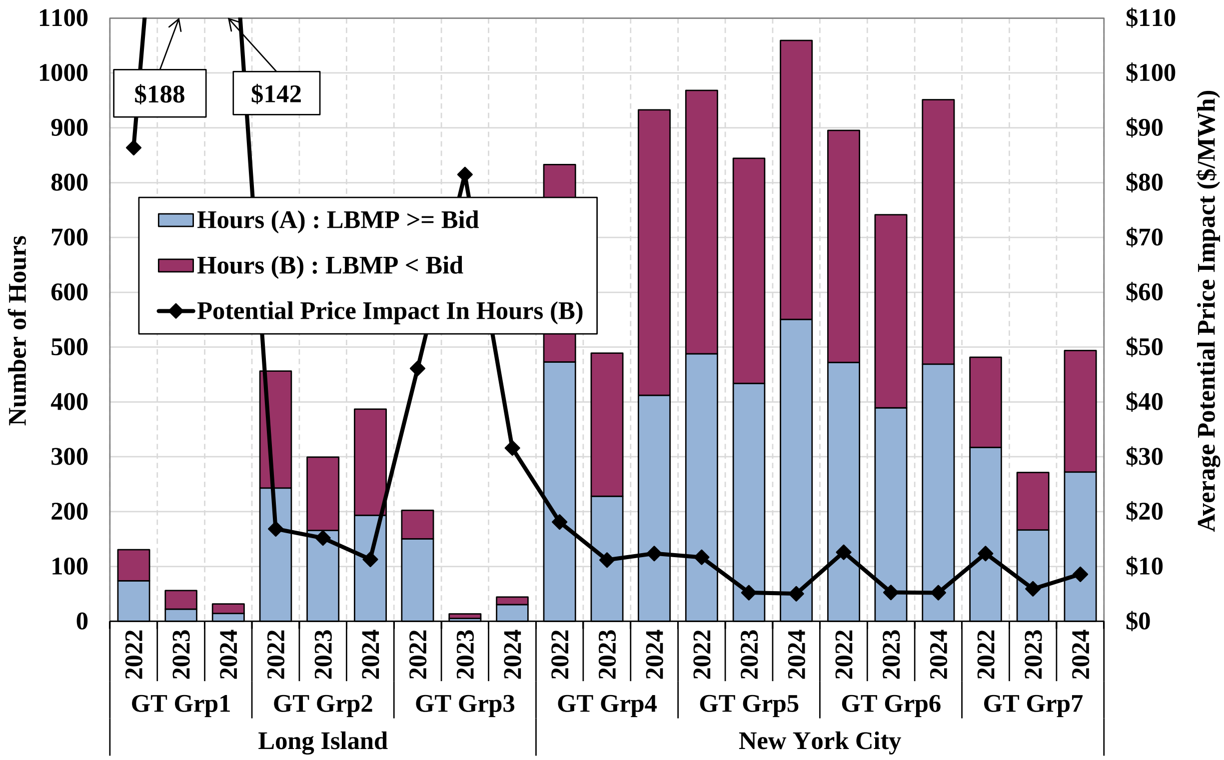


Figure 21 evaluates prices during economic commitments of gas turbines offering multi-hour minimum run times in the real-time market from 2022 to 2024.[61] Gas turbines in New York City and Long Island are combined into seven groups based on their electric connection to the grid.

Economic starts were more frequent among the four GT groups in New York City, ranging from approximately 300 to 1,100 hours each year over the past three years. However, LBMPs fell below GT costs in 48 percent of these hours. This disparity was largely due to these GTs not being eligible to set prices when their minimum run time offers exceed one hour. We estimate that if these GTs were allowed to set prices, the average LBMP during these hours would have been increased by up to $5-18 per MWh at various locations in New York City.

On Long Island, although the three GT groups had fewer economic starts each year, GT operating costs exceeded LBMPs in 45 percent of these start hours. The potential price impact was considerably higher at these Long Island locations, with estimated LBMP increases ranging from $11 to $188 per MWh during the affected hours. These potential LBMP increases correspond to an annual net revenue increase of $1-$6.5 per kW-year across various load pockets in New York City and Long Island, although price impacts could extend to broader areas depending on congestion patterns.

Given these inconsistencies between real-time prices and scheduling, we recommend NYISO revise its fast-start pricing criteria. Specifically, fast-start pricing eligibility should be based on the minimum run time used for scheduling, rather than on the submitted offer parameter, which is currently disregarded for real-time scheduling. By aligning these criteria, NYISO can enhance price efficiency and provide more appropriate investment signals for market participants.[62]

C. Dispatch Performance of Duct-Firing Capacity

Most combined cycle units in New York have duct burners, which use supplemental firing to increase the heat energy of a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. There are a total of 44 units across the state that can provide approximately 886 MW of duct-firing capacity in the summer and 917 such MW in the winter, collectively.[63] However, some duct-firing capacity is not always capable of following a five-minute dispatch signal.

61 Economic GT commitments include GT start-ups made economically by RTC, RTD, and RTD-CAM, excluding self-schedules. See Figure A-73 in the Appendix for more details of this analysis.

62 See Recommendation 2023-2.

63 See Table A-9 in the Appendix.

We show an example of a combined-cycle unit in the Appendix that could not follow dispatch instructions during a Reserve Pickup (RPU) event because its duct burner could not be fired in 10-minutes.[64] However, this duct burner capacity is treated as capable of following 5-minute dispatch signals in the market scheduling and pricing software. Given this inconsistency, suppliers with such capacity must decide whether to offer a service they are frequently not physically capable of providing.

Offers to Sell Duct-Firing Capacity that Cannot Perform Reliably

We estimate that, in 2024, on average:

- 109 MW was offered but not capable of following 5-minute ramping instructions; and
- 129 MW was scheduled for but not capable of providing 10-minute reserves.

These quantities present challenges in real-time operations especially under tight system conditions such as in an RPU event.

Capacity Not Offered Because of Limitations of Scheduling Software

The inflexibility of duct-firing capacity leads to several additional problems related to these combined cycle generators:

- Reduced energy offers – Some combined cycle units with a duct burner do not offer it into the real-time market. We estimate that an average of 50 MW of duct-firing capacity was unavailable for this reason in 2024.
- Reduced regulation offers – Some combined cycle units do not offer regulation in the real-time market because they face the risk of needing to regulate into their duct-firing range, where they may have limited ability to respond to AGC signals or may have higher operating costs and outage risks.[65]
- Reduced ramping and operating reserve offers – Some combined cycle units offer very conservative ramp rates for normal energy dispatch and operating reserves. A single *Emergency Response Rate* is used for operating reserves scheduling and is required to be greater than or equal to all *Normal Response Rates* that are used for normal energy dispatch. When units face the risk of providing operating reserves in the duct-firing range, they may offer both emergency and normal response rates far below their true capability in the non-duct range to comply with this requirement. Additionally, some units were disqualified from offering reserves because they were not able to perform in audits of the duct burner range. We estimate that an average of 46 MW of available 10 and 30-minute reserves in non-duct ranges were not offered for this reason in 2024.

64 See Appendix Section V.B for details about the analyses in this subsection.

65 Based on NYISO survey of participants with assets containing duct burners, less than 25 percent of this capacity has the ability to respond to AGC 6-second signals necessary for regulation movement while the duct-burners are operating.

We recommend NYISO consider alternative ways to schedule this capacity that takes into account the physical limitations of duct burners.[66] Ideally, this would: (a) allow generators to submit offers that reflect their true ramp capabilities in both the non-duct firing and duct-firing portion so energy and reserves could be scheduled appropriately and efficiently, and (b) allow generators to submit offers that limit their regulation range to exclude the duct-firing capacity.

Assessment of the NYISO Proposed Modeling Enhancements

NYISO proposed tariff changes in the *Improve Duct-Firing Modeling Project* to address the issues discussed above.[67] The enhancements would allow generators to identify an output range with slower ramp rates that could also be designated as ineligible to provide specific ancillary services the unit is eligible to provide at lower output levels. The project would also prevent RTD-CAM from dispatching combined cycle generators into the duct firing range. The proposal has potential to largely address the concerns raised above except for one critical consideration: the proposal does not make the ramp rate ranges (which would demarcate the duct-firing range) biddable parameters. Instead, the proposal would continue to set individual generator ramp rate ranges as administrative parameters that can only be modified after consultation with NYISO even though the physical capabilities of these units fluctuate with ambient conditions.[68]

Although we support the core modeling changes proposed by NYISO, if ramp rate ranges are not biddable parameters, it will undermine the objectives of the project. We illustrate in the Appendix of this report how the upper operating limit of a typical combined cycle varies across the hours of a single day based on ambient conditions.[69] Since duct firing ranges are generally the last block of output, the output level where duct burners need to fire varies daily and hourly.

In the Appendix, we analyze the implications of offering the duct-firing ranges of combined cycle generators with limited opportunities to adjust the ramp rate ranges assuming that suppliers are diligent in updating their ramp rate ranges twice per week based on recent weather trends.[70] The figure shows how much capacity across all combined cycle units with duct burners would have been mischaracterized as either: (a) baseload capacity incorrectly designated as slow-ramping duct burner capacity, or (b) duct burner capacity incorrectly offered as baseload capacity. The analysis shows that baseload capacity would be incorrectly designated as duct burner capacity when the forecasted conditions used to set the administrative ramp rates are warmer than actual conditions, while duct burner capacity would be incorrectly designated as

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66 See Recommendation 2020-1.

67 See *"Improve Duct-Firing Modeling"*, MC, October 31, 2024

68 The NYISO has committed to reviewing these consultation cases within 3-business days. See presentation.

69 See Figure A-76.

70 See Section V.B in the Appendix for the methodology and results of this analysis.

baseload if the forecasts were cooler than the actual conditions. The first type of error will be more frequent in the morning/evening hours when air temperatures are lower than average for a day, while the second type will be more common in the afternoon when temperatures are warmer than average. Attempts to minimize one type of error increases the other. The best approach to ensure that duct firing capability is accurately represented to the scheduling software is to permit biddable ramp rate for market participants.

D. Performance of Intermittent Power Resources during Curtailment

Intermittent power resources (IPRs), i.e., wind and solar generators, are usually scheduled at the level of NYISO's Wind/Solar Energy Forecast. However, the real-time dispatch model occasionally issues a Wind and Solar Output Limit ("Output Limit") to reduce output to manage flows over a transmission constraint. During constrained intervals, the LBMP is set by the offer price of the resource (which is typically negative) or another IPR in the area. To maintain system security and reliability, all generators (including IPRs) must follow dispatch instructions.

While generators are not always capable of following dispatch instructions perfectly, the NYISO rules impose financial penalties when a generator's production differs from the 5-minute instruction by more than 3 percent of its Upper Operating Limit (UOL).[71] The purpose of the financial penalties is to ensure that generators have incentives to follow dispatch instructions and that generators are not rewarded for threatening security and reliability.

Table 3 displays the performance of Wind and Solar IPR facilities in 2024 during economic curtailment events. Each resource had its actual curtailment performance evaluated against the estimated curtailment instruction and placed into performance categories of 10 percent tranches.[72] For each performance tranche, the table shows:

- **No. of Units:** the count of IPRs with average curtailment performance in the tranche
- **Percent of ICAP:** Total ICAP of all IPRs in that tranche
- **Percent of Economic Curtailment:** Percent of total IPR output curtailed

For example, 10 resources had an average performance of 80-90 percent during economic curtailments, representing 16.8 percent of all Wind and Solar IPR capacity and 2.9 percent of all energy curtailment instructed.

71 Section 5.2.4.3 of the Accounting and Billing Manual defines the 3-percent of UOL as the tolerance for IPRs in determining if an overgeneration charge ought to apply.

72 Average performance is calculated for each resource in RTD intervals when an Output Limit was imposed based on the difference between the generator's actual output and its economic basepoint plus 3-percent of its UOL. For a more detailed description of this figure, see Appendix Section V.C.

Overall performance during economic curtailments averaged close to 100 percent and most IPRs (60.5 percent of total capacity) respond at 80 percent or better performance. However, overall performance statistics are skewed by the fact that if an IPR does not respond to a curtailment instruction, the operators will be forced to dispatch another unit, leading the IPR to no longer be curtailed. Consequently, more than 96 percent of all curtailment instructions were placed on the 19-best performing resources. Nearly 40 percent of IPRs performed worse than 80 percent, with roughly 10 percent performing at a sub-30 percent rate. Poor performance by a few resources creates operational challenges that threaten transmission security, encouraging transmission owners to operate their equipment more conservatively, which would lead to more curtailment of renewable energy over time.

Table 3: Performance of IPRs during Economic Curtailment
2024

ance Range	No. of Units	Percent of ICAP	Percent of Economic Curtailment
0% to 10%	0	0.0%	0.00%
10% to 20%	3	8.7%	0.03%
20% to 30%	2	1.1%	0.05%
30% to 40%	0	0.0%	0.00%
40% to 50%	0	0.0%	0.00%
50% to 60%	2	7.7%	0.10%
60% to 70%	3	9.7%	0.16%
70% to 80%	5	12.3%	0.38%
80% to 90%	10	16.8%	2.90%
90% to 100%	19	43.7%	96.38%

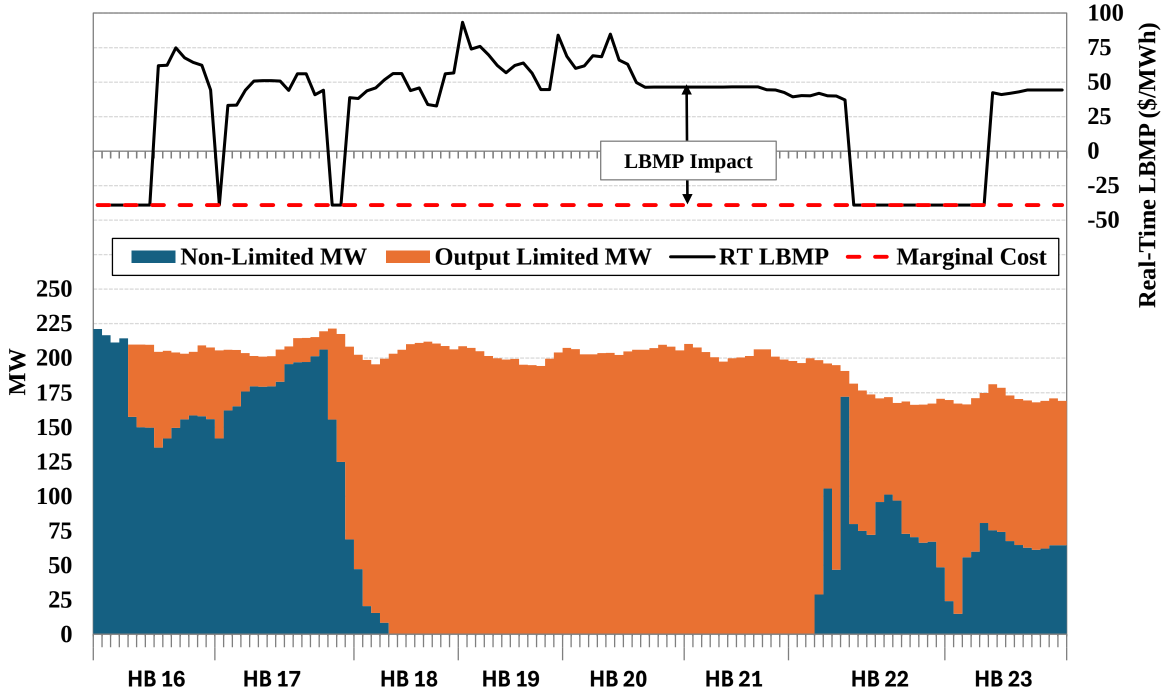
When an IPR does not follow curtailment instructions, it is frequently caused by connectivity issues between the generating facility and automated and/or remote operating systems. In our investigations of specific poor-performing IPRs, we have found that the failure to follow curtailment instructions is sometimes caused by the failure of systems controlled by the local transmission owner rather than the generating facility. During these events, the market model will first issue an Output Limit, but it becomes apparent that the IPR is not following instructions when large differences arise between the modeled transmission system flows and actual flows. In such cases, the operators are forced to curtail other, more-economic IPRs to correct for the non-responsiveness of the non-curtailing IPR.

Figure 22 examines a day when a wind generator did not follow curtailment instructions for an extended period, forcing the NYISO operators to manually curtail other IPRs to maintain transmission security. The primary axis shows the total generation from the IPR broken out by that which would not have been restricted by an Output Limit (blue columns) and the generation that ought to have curtailed (orange columns) in each interval of hours beginning 16-23 of that day. The secondary axis shows the real-time nodal LBMP (black line) at the non-responding

IPR along with an estimate of its marginal cost (red dashed line). Whenever these two lines diverge it indicates that the magnitude of the manual curtailments issued by the NYISO eliminated the constraint.

This event illustrates how IPRs sometimes benefit financially from not following dispatch instructions. First, the IPR produced 1200 MWh of excess output for which it received an estimated $133 per MWh of benefit relative to settlements had it followed its Output Limits.

Figure 22: Failure to Follow Curtailment Instructions
Event where IPR Unable to Respond to Output Limits, January 2024



Second, the LBMP was inflated by an average of roughly $69 per MWh over these intervals. Overall, the IPR received an additional $159,000 of net revenues by not obeying its instructions. On the other hand, several other IPRs were harmed by responding to manual curtailments, which caused them to miss out on REC sales and Production Tax Credits.

Review of the performance of individual IPRs when Output Limits are imposed highlights that mitigation and settlement rules do not provide sufficient disincentives for poor performance, especially if performance improvements would require some financial investment in more reliable control systems. Further, IPRs are rewarded for poor performance when operators are forced to manually curtail other competing resources. Balancing settlement rules include an overgeneration charge based on the maximum of the regulation capacity price in the day-ahead and real-time. This charge may not outweigh the benefits an IPR receives from ignoring Output Limits if either their bids are sufficiently above reference level or if manual curtailments are necessary and LBMPs never turn negative.[73] To address these concerns, we recommend changes to the overgeneration charge to provide incentives for IPRs to follow dispatch instructions.[74]

E. Supplemental Commitment for Reliability

Supplemental commitments occur when a generating unit is committed to address local or systemwide reliability needs not reflected in the day-ahead and/or real-time markets. There are several types of supplemental commitments:

- **Day-Ahead Reliability Units (DARU)** commitment occurs before the day-ahead market at the request of transmission owners or NYISO for anticipated reliability needs;
- **Day-Ahead Local Reliability Rule (LRR)** commitment occurs within the day-ahead market's economic commitment process specifically to meet un-priced local reliability needs in New York City;
- **Supplemental Resource Evaluation (SRE)** commitment occurs after the day-ahead market at the request of transmission owners or NYISO for reliability; and
- **Forecast Pass Commitment (FCT)** occurs within the day-ahead market after the economic pass if it does not schedule enough physical resources to satisfy forecasted load and reserve requirements.

These OOM commitments highlight gaps in the market design, indicating a need for reliability services that the market is currently not procuring efficiently. Moreover, OOM commitments tend to depress energy and reserves prices, which undermines incentives for the market to maintain reliability and generates uplift costs. Hence, it is important to minimize supplemental commitments and look for ways to procure the underlying reliability services through the day-ahead and real-time market systems.

1. Supplemental Commitment in New York State

Figure 23 summarizes four types of reliability commitment (DARU, LRR, SRE, and Forecast Pass) by region in 2023 and 2024.[75] In 2024, approximately 400 MW of capacity was committed on average for reliability, marking a 9 percent decrease from 2023. The decline was largely attributable to a 29 percent reduction in New York City for reasons evaluated further below.

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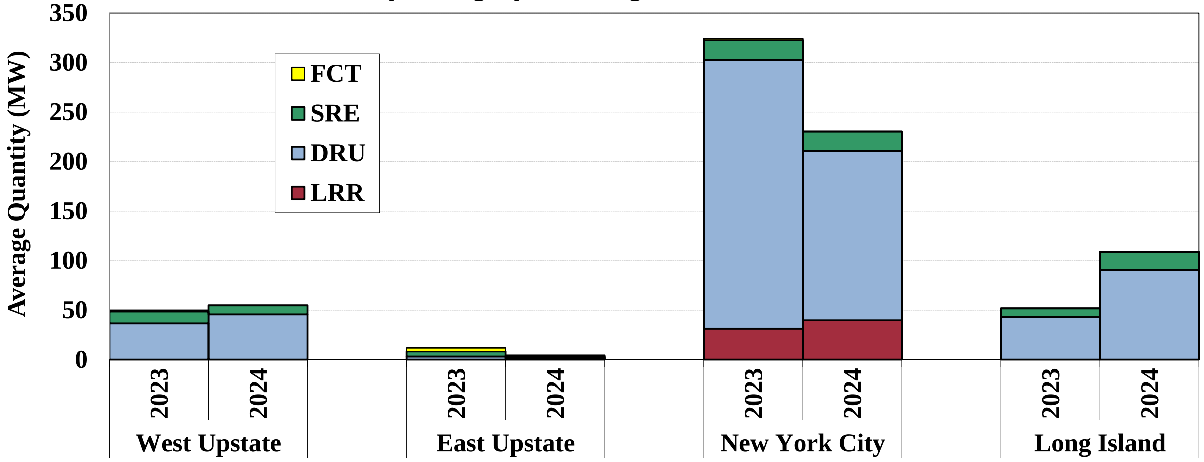
73 When the real-time LBMP is negative, the net change to a non-responsive IPR's balancing settlement can be given by the formula: $\boldsymbol{(E_{RT} - E_{BP}) * (LBMP_{RT} + CREDIT) + P}$, where E_{RT} = Real-time Actual Output in MW from the resource; E_{BP} = the economic basepoint of the unit; $LBMP_{RT}$ = Real-time LBMP; CREDIT is the sum of the value per MWh of the applicable PTC and RECs to the resource; and P = Overgeneration Charge which is 0 if the Actual Output is less than or equal to the Basepoint plus 3% of UOL. This equation will yield a positive value if (CREDIT + LBMPRT) > P. For more details, see Appendix Section V.C.

74 See Recommendation 2023-3.

75 See Section V.J in the Appendix for a description of the figure.

Figure 23: Supplemental Commitment for Reliability in New York
By Category and Region, 2023-2024



Conversely, reliability commitments increased on Long Island, particularly in the first and second quarters when steam turbines were committed to manage high voltage issues during periods of light load. Reliability commitments to satisfy N-1-1-0 criteria (i.e., normal line loading after the two largest contingencies) occurred on 10 high load days in 2024, indicating that the current Long Island 30-minute reserve requirement is inadequate. The absence of these criteria in the market software forces system operators to resort to OOM commitments when needed, leading to understated prices and poor market incentives. Modeling reserve requirements in the Long Island load pockets where these OOM actions are used would improve efficiency and encourage new resources to locate where they are most valuable. Hence, we recommend that the NYISO implement local reserve requirements in Long Island that are adequate to maintain reliability rather than rely on out-of-market actions.[76]

Additionally, although the day-ahead and real-time markets schedule resources to satisfy reserve requirements on Long Island, reserve providers are currently not paid reserve clearing prices corresponding to these requirements. Instead, they are paid based on the clearing prices for the larger Southeast New York region. Compensating reserve providers in accordance with the market scheduling decisions would improve market incentives, providing better signals to new investors over the long term. Hence, we recommend the NYISO set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.[77] The NYISO plans to implement this recommendation along with the Dynamic Reserves project.[78]

[76] See Recommendation 2024-1.

[77] See Recommendation 2019-1.

[78] See "Long Island Reserve Constraint Pricing", MIWG, February 7, 2024.

In upstate regions, OOM commitments increased in 2024, primarily to satisfy N-1-1 criteria in the North Country load pockets, which occurred on 205 days compared to 143 days in 2023. As in New York City and Long Island, we recommend modeling these local reserve requirements to improve market efficiency and establish proper market signals for future investments.[79]

2. Reliability Commitment in New York City and North Country Load Pockets

Table 4 further examines reliability commitments made by the local transmission owner in New York City and by NYISO for North Country load pockets, which accounted for most reliability commitments in 2024.[80] We evaluate OOM commitments to ensure they are necessary for reliability and cost-effective and to identify potential gaps in NYISO's market design.[81]

Table 4: Reliability Commitment in New York City and North Country
2024

Category of Reliability-Committed Capacity	New York City		North Country	
	Committed Capacity (GWh)	% of Total	Committed Capacity (GWh)	% of Total
Economic	332	14%	75	28%
Verified - Needed	178	8%	150	55%
Verified - Headroom	883	37%	40	15%
Unverified	965	41%	5	2%
Total GWh	**2359**		**271**	

In 2024, OOM commitments to satisfy reserve requirements occurred on 205 days in the North Country load pockets and 238 days in New York City load pockets. In New York City, 59 percent of these commitments were verified by the MMU as either economic or necessary to satisfy specific reliability requirements based on applicable system conditions related to forecasted load, the status of generation and transmission, and contingencies. Conversely, 98 percent of North Country commitments were verified as economic or needed for reliability. The large "unverified" reliability commitments in New York City may result from several factors: (a) DARU requests are routinely made two to five days in advance for consecutive days, and forecasts are often less accurate when the DARUs are requested; and (b) the local transmission owner may have operational requirements that are not known by the MMU or NYISO.

Notably, a significant portion of these commitments, 37 percent in New York City and 15 percent in North Country, were categorized as surplus headroom on the units beyond the needed

79 See Recommendation 2024-1.

80 See Section V.J in the Appendix for more details for this analysis.

81 NYISO's *Day Ahead Scheduling Manual*, Section 4.2.6 requires a TO requesting the commitment of unit for reliability to provide the reason and NYISO to review and validate the request.

generation level, including hours committed to satisfy Minimum Run Time requirements. This was due to limited flexible generation options available to meet these reliability needs. Smaller flexible resources like batteries and DERs could offer more cost-effective reliability solutions. However, current market structures do not provide incentives for satisfying these local needs. Given the significant influence of OOM reliability commitments on resource scheduling and pricing, we recommend NYISO model the underlying N-1-1 and N-1-1-0 requirements explicitly as local reserve requirements, which would encourage investment in smaller dispatchable resources (e.g., batteries and DERs) to effectively satisfy these reliability needs.[82]

3. Forecast Pass Commitment

Forecast pass commitments were infrequent, and the total committed capacity was small. Nonetheless, we identified two issues in this process. First, certain quick-start capacity was incorrectly categorized as slow-start capacity in the Forecast Pass. Consequently, most FCT commitments would not have occurred if these quick-start units were properly classified.[83] Software changes would be necessary to correct this issue. Second, our evaluation showed that the physical energy and reserves scheduled in the day-ahead market were frequently below forecasted load and reserve requirements.[84] Thus, NYISO holds substantial reserves on resources not scheduled (or compensated) in the day-ahead market. It would be beneficial to explicitly model this reliability need as a reserve requirement, and to procure and price such reserves in the market by setting dynamic reserve requirements.[85] In some cases, reserve requirements could be satisfied by resources with longer lead times than the current 10 and 30-minute reserve providers. Hence, we recommend that NYISO evaluate the need for longer lead-time reserve products.[86] Before creating longer lead-time reserve products, it may be more efficient to represent such requirements in the market with a 30-minute reserve requirement. NYISO should consider these tradeoffs in its evaluation of dynamic reserves.

F. Guarantee Payment Uplift Charges

When suppliers scheduled by NYISO do not fully recover their as-offered costs from energy and ancillary services sales, they receive supplemental guarantee payments. NYISO recovers these payments through guarantee payment uplift charges. However, these uplift charges are difficult to hedge and do not provide transparent economic signals to market participants and potential

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82 See Recommendation 2024-1.

83 See Section V.J in the Appendix for more information about this analysis.

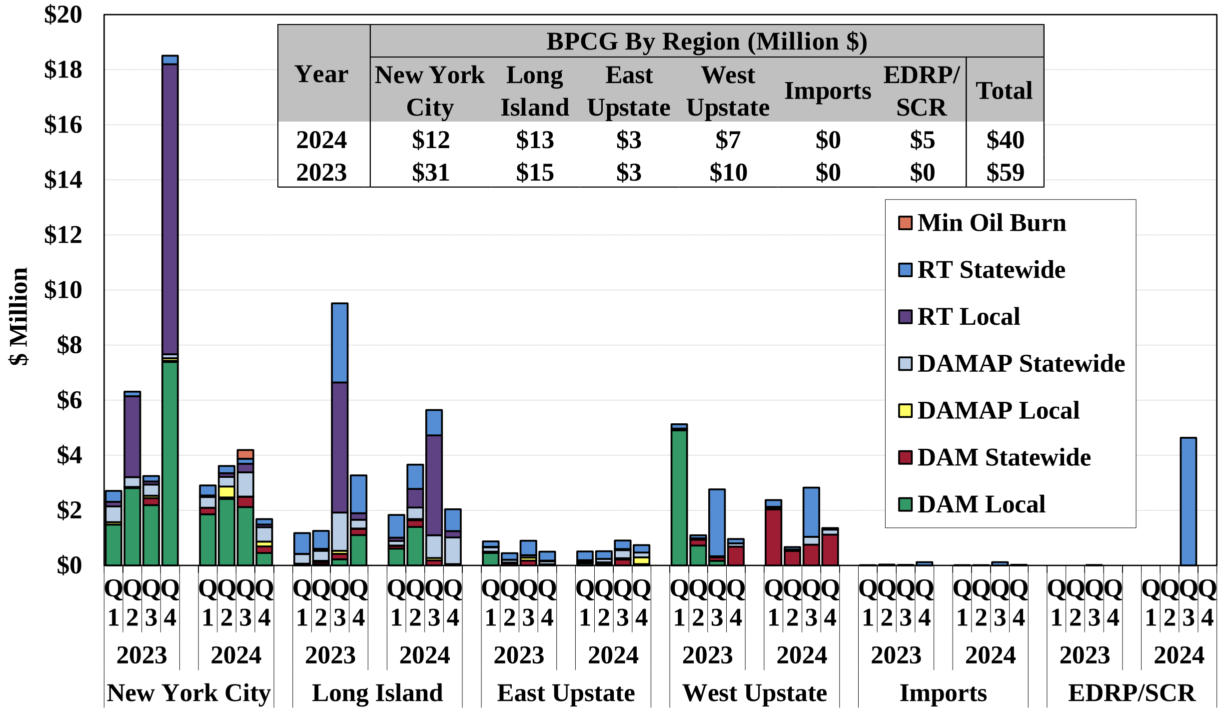
84 See Section V.J in the Appendix for more information about this analysis.

85 See Recommendation 2015-16.

86 See Recommendation 2021-1. NYISO's *2024 Market Vision* report states it will evaluate longer look-ahead reserve products in the *Balancing Intermittency Phase 2* project beginning in 2026.

investors. Therefore, it is important to minimize these charges. When the markets reflect reliability requirements and system conditions efficiently, uplift charges should be relatively low. Figure 24 shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2023 and 2024 on a quarterly basis.[87]

Figure 24: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2023 – 2024



Guarantee payment uplift totaled $40 million in 2024, marking a 32 percent decrease from 2023 despite increases in natural gas prices, CO_2 emission costs, and load levels in 2024. The reduction occurred primarily in New York City but was partially offset by a $5 million BPCG payment to demand resources due to multiple SCR activations by NYISO on high load days.

New York City experienced higher BPCG uplift in 2023 largely because certain dual-fuel steam turbines received approximately $20 million in BPCG payments during two local gas pipeline outages in June and October. Since these units require natural gas to ramp up incremental output, the local transmission owner kept them online and operated them at a higher output level on oil to provide local reserves throughout the outage periods. Excluding these specific events, BPCG uplift in New York City was relatively consistent from 2023 to 2024, as reductions in supplemental commitments offset impacts from higher gas prices, emission allowance costs, and load levels. In 2024, more than 60 percent of New York City BPCG uplift was paid to generators committed to satisfy N-1-1-0 local requirements. Since these reserve requirements are satisfied using OOM commitments and costs are recovered through guarantee payments,

87 See Section V.K in the Appendix for a more detailed description of this analysis.

market incentives to satisfy these requirements are very weak. We have recommended that NYISO explicitly model local reserve requirements to satisfy these N-1-1-0 needs, which would greatly reduce associated BPCG uplift and provide more transparent and efficient price signals to the market.[88]

BPCG uplift on Long Island fell modestly in 2024. Nearly $5 million was paid in the category of real-time local BPCG uplift, with 85 percent going to high-cost peaking resources that were frequently needed in the summer months to satisfy the Transient Voltage Recovery (TVR) needs on the East End of Long Island. We have recommended NYISO consider modeling local TVR requirements on Long Island in the day-ahead and real-time markets.[89] Our estimates have shown significant impact on LBMPs in the Long Island load pockets from this potential modeling improvements, which should provide a more efficient market signals for investment that tends to help satisfy reliability criteria and relieve congestion.[90] Additionally, approximately $2 million of DAMAP accrued on Long Island GTs, most of which resulted from the inconsistency between scheduling and pricing of reserves, as reserve clearing prices do not account for the costs of satisfying the reserve market requirements. We have recommended NYISO set reserve clearing prices for Long Island that consider all binding reserve constraints in the market scheduling model.[91]

West New York accounted for roughly $7 million in BPCG uplift payments in 2014, mostly going to units that supplementally committed to manage local reserve needs in the North Country load pockets (205 days). Incorporating more of these requirements into the day-ahead and real-time markets would enhance market efficiency and effectiveness.[92]

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88 See Recommendation 2024-1.

89 See Recommendation 2021-3.

90 See Section VII.B for this analysis.

91 See Recommendation 2024-1.

92 See Recommendation 2024-1.

VII. Transmission Congestion and TCC Contracts

Congestion arises when the transmission network lacks sufficient capacity to dispatch the least expensive generators to satisfy demand. When congestion occurs, the market software establishes Location-Based Marginal Prices (LBMPs) to reflect the cost of serving load at each location on the network. These LBMPs reflect that higher-cost generation is required at locations where transmission constraints limit the ability to deliver lower-cost power.

Congestion charges are applied to purchases and sales (including bilateral transactions) in both the day-ahead and real-time markets, based on the congestion components of respective LBMPs.[93] Market participants can hedge day-ahead congestion charges by owning Transmission Congestion Contracts (TCCs), which entitle the holder to payments corresponding to the day-ahead congestion charges between two locations. However, no TCCs are sold for real-time congestion, as most power is scheduled through the day-ahead market.

Transmission owners recover part of the embedded cost of building and maintaining the transmission network through revenues from TCC sales and day-ahead congestion charges. When transmission capability is sold in the TCC auctions, day-ahead congestion revenues are used to compensate TCC holders. Any residual revenue is paid to transmission owners. The remaining embedded costs are recouped by Transmission Owners through a flat Transmission Service Charge (TSC), assessed per MWh of real-time withdrawals.

This section discusses four key aspects of congestion management in 2024:

- Day-ahead and real-time transmission congestion revenues (Subsection A),
- Transmission constraints managed using out-of-market actions (Subsection B),
- TCC prices and payments (Subsection C),
- Allocation of day-ahead congestion residuals (Subsection D),

In addition, general congestion patterns are summarized in the Appendix Section III, while the Market Operations section and its corresponding appendix evaluate other elements of congestion management.[94]

A. Day-ahead and Real-time Transmission Congestion Revenues

This subsection analyzes congestion that is managed by scheduling resources in the day-ahead and real-time markets to provide relief.

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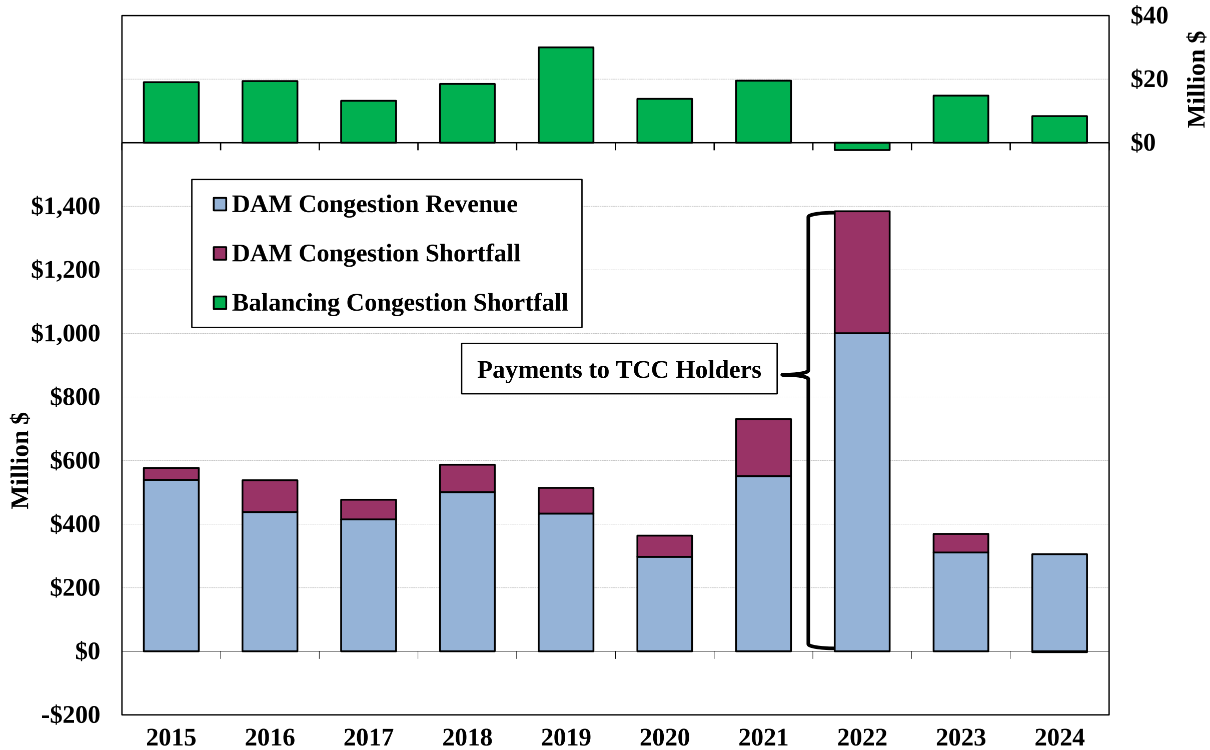
93 Congestion charges to bilateral transactions scheduled through the NYISO are based on the difference in congestion component of the LBMP between the two locations (i.e., the sink minus the source).

94 See evaluations of pricing during transmission shortages (VI.A and coordinated congestion management with PJM (Appendix V.E).

Figure 25 evaluates overall congestion revenues and shortfalls in the past ten years, showing annual summaries for the following categories:

- **Day-ahead Congestion Revenues** – These are collected by NYISO when power is scheduled to flow across congested transmission lines in the day-ahead market.
- **Day-ahead Congestion Shortfalls (and Surpluses)** – Shortfalls occur when day-ahead congestion revenue collections are less than payments to TCC holders. This typically happens when the amount of TCCs sold exceeds the actual transmission capability modeled in the day-ahead market. Shortfalls highlight outages and other factors that reduce transmission capability over constrained interfaces. Conversely, surpluses occur when day-ahead schedules utilize transmission capability not sold in the TCC auctions.
- **Balancing Congestion Shortfalls (and Surpluses)** – These arise when actual real-time flows over a constraint differ from those scheduled in the day-ahead market. Shortfalls occur when day-ahead scheduled flows exceed real-time flows, often due to outages, loop flows, modeling inefficiencies, or other operational limitations. Surpluses occur when real-time schedules utilize more transmission capability than is day-ahead scheduled.

Figure 25: Congestion Revenues and Shortfalls
2015 – 2024



The figure shows that day-ahead congestion revenues, day-ahead congestion shortfalls, and balancing congestion shortfalls all declined from 2023, approaching the lowest levels seen over the past decade. We discuss these changes further in the subsections below.

1. Day-Ahead Congestion Revenues

Despite increases in natural gas prices, emission allowance costs, and load levels, day-ahead congestion revenues fell slightly from $311 million in 2023 to $306 million in 2024, just above the decade-low of $297 million recorded in 2020. The primary driver of this reduction was the completion of the AC Transmission Segment A and Segment B projects at the end of 2023. These projects eliminated the need for lengthy transmission outages which required construction work and increased transfer capability across the Central-East and UPNY-SENY interfaces. Additionally, lower net imports from Quebec further reduced West-to-East congestion.

As a result, although transmission facilities alongside the Central-East interface remained the largest contributor to day-ahead congestion in 2024, its share dropped significantly from 53 percent in 2023 to just 24 percent.[95] This reduction was partially offset by higher natural gas prices and greater regional gas spreads during the winter months of 2024, which typically exacerbate Central-East congestion.

Long Island congestion levels remained relatively stable between 2023 and 2024, continuing to account for the second largest share of day-ahead congestion. Major transmission outages have been the primary driver over the past two years. One of the two 345 kV lines connecting upstate to Long Island was out of service for approximately 200 days in each year, greatly reducing import capability from upstate regions.

Unlike other regions, New York City facilities and West-to-Central lines experienced notable increases in day-ahead congestion in 2024. In New York City, more than 40 percent of this congestion occurred during two cold spells in mid-January and late December, driven by tight gas supply and elevated gas prices. Most of the West-to-Central congestion occurred on the Scriba-Volney 345 kV line, which frequently limited exports of gas-fired and nuclear generation from the Oswego Complex during high load conditions in the summer months.

2. Day-Ahead Congestion Shortfalls

Table 5 shows day-ahead congestion shortfalls for selected transmission facility groups.[96] Day-ahead congestion shortfalls fell from $59 million in 2023 to a net surplus of $3 million in 2024. This marks the first time in the past decade that an annual net surplus has been recorded.

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95 See Appendix Section III.B for congestion revenues by transmission facility group.

96 Appendix Section III.F provides descriptions and detailed results for each transmission facility group.

Table 5: Day-Ahead Congestion Shortfalls in 2024

Facility Group	Annual Shortfalls ($ Million)
Central to East	-$18.4
North to Central	$7.8
Long Island Lines	
901/903 PARs	-$9.4
Other Factors	$8.7
New York City Lines	$6.2
All Other Facilities	$2.2

Transmission outages have been the primary driver of day-ahead congestion shortfalls in recent years. In 2024, several key outages contributed significantly to these shortfalls:

- **North to Central New York** – Multiple transmission outages occurred throughout the year to accommodate work on the Smart Path Connect Project in the North and Mohawk Valley load zones.
- **Long Island** – The Dunwoodie-Shore Road 345 kV circuit ("Y50 line") was out of service for more than 200 days, spanning two extended periods, including nearly the entire first quarter and again from mid-June to late October.
- **New York City** – The Dunwoodie-Mott Haven 345 kV circuit ("71 line") was out of service in January and February, while the Mott Haven-Rainey 345 kV circuit ("Q12 line") was out of service on most days in April.

NYISO allocates day-ahead congestion shortfalls that result from qualifying transmission outages to responsible transmission owners.[97] In 2024, NYISO allocated $30 million in shortfalls in this manner, with the outages listed above accounting for the majority of the total. This allocation mechanism provides transmission owners with incentives to minimize the costs and duration of planned outages.

However, these outage-driven shortfalls were offset by two primary sources of day-ahead congestion surpluses:

- **PAR-controlled lines between New York City and Long Island** – The 901 and 903 lines generated over $9 million in day-ahead congestion surpluses due to differences between the TCC auctions and the day-ahead market in assumed flows from Long Island to New York City across the two lines. Normally, ConEd has a contractual right to flow up to 300 MW from upstate New York through Long Island to New York City, but since LBMPs are typically higher in Long Island, revenue surpluses are created when ConEd schedules less than 300 MW to flow from Long Island to New York City in the day-ahead market. In 2024, these schedules were reduced on most days because of the extended outage of the Y50 line which flows power from upstate to Long Island.

[97] The allocation method is described in NYISO Open Access Transmission Tariff, Section 20.

- **New transmission facilities** – Some new facilities related to the Public Policy Transmission Projects were modeled as out-of-service in TCC auctions but as in-service in the day-ahead market, leading to congestion surpluses of more than $20 million.

Currently, these surpluses are not allocated to responsible transmission owners. Instead, they are socialized across all transmission owners in proportion to their TCC auction revenues. The allocation of day-ahead shortfalls and surpluses is discussed further in Subsection D.

3. Balancing Congestion Shortfalls

Table 6 shows balancing congestion shortfalls by transmission facility group in 2024.[98] [99] Unlike day-ahead shortfalls, balancing congestion shortfalls are generally socialized to all NYCA load through Rate Schedule 1 charges.[100]

Table 6: Balancing Congestion Shortfalls in 2024

Facility Group	Annual Shortfalls ($ Million)
External Interfaces	$8.3
TSA Contraints	$3.8
Central to East	-$3.8
All Other Facilities	-$1.1

Congestion shortfalls are modest on most days but can escalate significantly on a limited number of days due to unexpected events. For example, during the Thunderstorm Alert events, transfer capability into Southeast New York was greatly reduced, contributing nearly $4 million in congestion shortfalls from approximately a dozen occurrences over the summer months.

External interfaces accounted for the majority of balancing congestion shortfalls in 2024, totaling more than $8 million. Most of these shortfalls accrued on the primary PJM interface in December. Beginning December 20, NYISO operators utilized OOM actions to secure the Watercure-Oakdale 345 kV circuit ("31 line") against potential simultaneous outages of the Nine Mile 2 and Fitzpatrick nuclear generators. The primary operational responses included curtailing scheduled transactions and reducing import limits across the primary PJM interface. This out-of-market approach persisted until the end of January 2025, when a revised operational procedure for Fitzpatrick was developed to prevent the simultaneous loss contingency scenario. When a transmission constraint is managed by curtailing and limiting imports, it results in balancing

98 Appendix III.F provides additional details on balancing congestion shortfalls.

99 The balancing congestion shortfalls estimated in this table differ from actual balancing congestion shortfalls because the estimate: (a) is partly based on real-time schedules rather than metered injections and withdrawals; and (b) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of price corrections and Scarcity Pricing Adjustments.

100 The only exception is that some balancing congestion shortfalls from TSA events are allocated to Con Ed.

congestion shortfalls, which are allocated to end users through Rate Schedule 1. If the constraint had been managed explicitly in the market software, these costs would be allocated to the two generators through LBMPs instead of being uplifted to end users.

However, these shortfalls were partially offset by surpluses generated on the Central-East interface, resulting from increased transfer capability due to operational adjustments to the status of nearby capacitors and static voltage compensators, as well as real-time operations under the PJM-NY M2M process.

B. Management of Constraints using Out-of-Market Actions

Transmission constraints on facilities rated 100 kV and above are generally managed through the day-ahead and real-time markets. This approach provides several key benefits, including:

- **More efficient resource scheduling** that optimally balances the costs of satisfying demand, ancillary services, and transmission security requirements; and
- **More efficient price signals** that inform longer lead-time decisions, such as fuel procurement, generator commitment, external transaction scheduling, and investments in generation and transmission infrastructure.

However, certain transmission constraints, particularly those on lower voltage networks, are resolved primarily through out-of-market actions, such as:

- Out of merit dispatch and supplemental commitment of generation;
- Curtailment of external transactions and limitations on external interface transfer limits;
- Use of internal interface or constraint transfer limits that serve as proxies for limiting transmission facilities; and
- Adjusting PAR-controlled line flows on the higher voltage network.

In April 2021, NYISO first began to incorporate a limited set of 69 kV constraints on Long Island in the day-ahead and real-time markets.[101] This has allowed resources previously dispatched out-of-merit to manage these constraints to be scheduled economically, which has helped improve the efficiency of scheduling, pricing, and market incentives.

Out-of-market actions to manage constraints remain common in some areas. Table 7 shows the frequency of such actions by region, displaying the number of days in 2023 and 2024 when OOM actions were used.[102] New York City experienced the most frequent OOM actions of any

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101 The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models. The Brentwood-Pilgrim 69 kV line and the Elwood-Pulaski 69 kV line were incorporated in April 2021. The Deposit-Indian Head 69 kV line and the West Hempstead-Malverne 69 kV line were incorporated in April 2022. The Holtsville-West Yaphank 69 kV line was incorporated in March 2023.

102 See Section III.D in the Appendix for more details on the use of various resource types.

region in the past two years. Most of these actions were commitments to satisfy N-1-1-0 requirements in New York City load pockets. In the North Zone, OOM actions were frequent as well, primarily to commit generation to satisfy N-1-1 requirements in the North Country load pockets, which are not currently modeled in the day-ahead and real-time markets. Large OOM commitments in these local pockets often occurred on days with relatively low reserve needs, leading to sizable surplus headroom on the OOM-committed units and substantial uplift costs. These OOM commitments are evaluated in more detail in Section VI.E.

Table 7: Summary of OOM Days for Managing Network Security and Reliability
2023-2024

Area	# of Days with OOM Actions	
	2023	2024
North Zone	188	225
New York City	265	242
Long Island	172	182
All Other Regions	68	38

On Long Island, supplemental commitments were typically made for reserve needs under tight system conditions, often driven by severe weather, constrained gas supplies, emergency outages of inter-ties, or generator trips. Although Long Island experienced relatively few of these OOM commitments over the past two years, it would be still beneficial to consider modeling the full reserve requirements in the day-ahead and real-time markets.[103] Incorporating N-1-1 requirements into the market software for key local areas, such as New York City, Long Island, North Country load pockets, would improve scheduling efficiency, provide more efficient investment signals, and help integrate renewable and storage resources.

Aside from OOM commitments for local reserve needs, Long Island experienced the most frequent OOM actions to manage low-voltage network constraints. Table 8 summarizes the frequency of these actions in 2023 and 2024, including total hours and days in which OOM actions were taken to manage 69 kV constraints and Transient Voltage Recovery (TVR) constraints in four areas of Long Island. The table also shows the average estimated LBMP in each pocket based on the marginal costs of resources used to manage these constraints.

OOM actions to secure 69 kV facilities on Long Island have become less frequent since April 2021, when NYISO began incorporating 69 kV constraints in the market software. As a result, resources that were previously dispatched out-of-merit to manage these constraints were instead scheduled economically on 112 days in 2023 and 162 days in 2024. Overall, OOM actions to

103 See Recommendation 2024-1.

manage 69 kV constraints have declined more than 50 percent from the levels typically seen prior to 2021. Nonetheless, in the valley stream load pocket, gas turbines were still needed on 40 to 50 days in each of the last two years to secure 69 kV transmission constraints involving a contingency not modeled in the market software.

Table 8: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2023-2024

Year	Long Island Load Pockets	69kV OOM		TVR OOM		Avg. LBMP	Est. LBMP w/ Modeling Local Constraints
		#Hours	#Days	#Hours	#Days		
2023	Valley Stream	473	41			$38.97	$44.46
	Brentwood	33	5			$40.19	$40.25
	East of Northport	114	16			$43.52	$44.37
	East End	44	8	676	69	$44.31	$61.20
2024	Valley Stream	371	49			$41.30	$42.58
	Brentwood	5	2			$41.41	$41.43
	East of Northport	82	9			$43.27	$43.44
	East End	20	5	646	63	$44.04	$57.92

NYISO has a process to periodically evaluate and incorporate additional 69 kV constraints into the market models as needed. This process should continue to reduce OOM needs on Long Island and improve scheduling and pricing efficiency. Setting more efficient LBMPs that recognize the marginal cost of satisfying local transmission constraints will provide better signals for future investment. However, this process does not address the TVR requirements on the East End of Long Island where OOM actions are frequent on high load days in the summer months. The high costs of turning on oil-fired resources to meet the TVR needs are not currently reflected in LBMPs. Hence, we recommend NYISO model East End TVR needs (using surrogate constraints) in the market software.[104] We illustrate in Section III.E of the Appendix one approach to develop surrogate constraints that could be used to satisfy TVR constraints within the market models.

C. Transmission Congestion Contract Prices and Payments

We evaluate the performance of the TCC market by examining the consistency of TCC auction prices and congestion prices in the day-ahead market for the Winter 2023/24 and Summer 2024 Capability Periods (i.e., November 2023 to October 2024). Table 9 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[105]

104 See Recommendation 2021-3.

105 Appendix Section III.H describes how we break each TCC into inter-zonal and intra-zonal components.

- The *TCC Profit* measures the difference between the *TCC Payment* and the *TCC Cost*.
- The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path.
- The *TCC Payment* is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points.

Table 9: TCC Cost and Profit
Winter 2023/243 and Summer 2024 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
Central Zone	$37	-$9	-23%
Mohawk VL	-$23	$19	-82%
Capital Zone	$25	-$13	-53%
Long Island	$10	$10	96%
New York City	$12	$0	3%
All Other	$5	-$2	-32%
Total	**$66**	**$5**	**8%**
Inter-Zonal TCC			
Other to Central New York	$26	-$13	-50%
Other to Southeast New York	$69	-$58	-84%
New York to New England	$78	-$59	-76%
All Other	$14	$7	46%
Total	**$187**	**-$124**	**-66%**

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2023 to October 2024 incurred a net *loss* of $118 million. Overall, TCC holders experienced a *negative* return of 47 percent (as a weighted percentage of the original TCC prices), compared to a *negative* return of 66 percent in the previous 12-month period. TCC holders experienced average *losses* of 66 percent on inter-zonal transmission paths, while realizing an average *gain* of 8 percent on intra-zonal paths.

Substantial losses, totaling $117 million, occurred on transmission paths crossing the Central-East interface, into Southeast New York, and across the border to New England. These losses coincided with a 54 percent reduction in day-ahead congestion revenue along these transmission paths from 2023 to 2024. The reduction was driven primarily by lower net imports from Quebec, fewer transmission outages, and increased transfer capability following the completion of major transmission upgrades, all of which greatly eased west-to-east transmission bottlenecks. This reduction was not well anticipated at the time of the auctions, TCC holders consequently suffered losses on most intra-zonal and inter-zonal transmission paths within the affected regions. Conversely, participants realized a profit of $19 million on intra-zonal paths in the

Mohawk Valley zone. This profit can be attributed primarily to TCC holders benefiting from higher congestion in the TCC auction than in the day-ahead market on counter-flow transmission paths.

These findings suggest that TCC prices generally align with the levels of congestion anticipated at the time of the auctions. The profits and losses of TCC bidders on most transmission paths typically correlate with changes in day-ahead congestion patterns from previous years, emphasizing the importance of anticipated congestion levels in evaluating TCC profitability. Further, unexpected congestion, often triggered by lengthy unplanned outages, frequently serves as a key driver of TCC profitability. TCC auction results also suggest that market expectations of congestion improve closer to real-time operations, consistent with the availability of more accurate information about the state of the transmission system and market conditions.

D. Allocation of Day-Ahead Congestion Shortfalls and Surpluses

Day-ahead congestion shortfalls and surpluses (“residuals”) occur when day-ahead network capability differs from the modeled capability in the TCC auctions. Shortfalls arise when the day-ahead flows over a binding constraint are lower than the transfer capability used by TCCs, while surpluses occur when day-ahead flows exceed the transfer capability used by TCCs. In general, it is beneficial to allocate surpluses and shortfalls on a “cost causation” basis because this provides efficient financial incentives for Transmission Owners (TOs) to maintain equipment, configure the transmission system, and schedule outages. This subsection evaluates various categories of residuals and the extent to which they are allocated efficiently.

Shortfalls and surpluses are allocated to the responsible TO when they result from most changes in modeled transfer capability. These include qualifying transmission outages, return-to-service of transmission, facility uprates, and facility derates that can be attributed to a specific TO. This allocation is based on the flow impacts of these factors on binding constraints in the day-ahead market and is consistent with a cost causation principle.[106] However, the remaining shortfalls and surpluses are allocated in proportion to the TCC auction revenues received by each TO, which does not align with cost causation principles.[107]

The following example illustrates how the allocation of surpluses may not always align with cost causation principles. Consider a scenario where a transmission constraint binds in the day-ahead market with a scheduled flow of 300 MW, while TCCs have been previously sold utilizing only 260 MW of transfer capability. This implies that the constraint is undersold by 40 MW. If the additional 40 MW becomes available due to an uprate of the facility after the TCC auction, the TO receives congestion surpluses corresponding to these additional 40 MW from the day-ahead

[106] See OATT, Attachment N, Formula N-6 through N-14 for the calculation of these allocations.

[107] See OATT, Attachment N, Formula N-15 for the calculation of this allocation.

market. Conversely, if the additional 40 MW arises solely because fewer TCCs were sold than the available transfer capability, the responsible TO receives only a small portion of the resulting congestion surpluses. This allocation method is inefficient as it unfairly penalizes TOs that own equipment on interfaces that bind under multiple transmission flow patterns.[108]

Table 10 shows actual allocations of day-ahead congestion residuals over the past four years, categorized into two distinct groups. The first category includes allocations based on the cost causation principle, following Formulas N-6 through N-14 in the OATT Attachment N. The second category consists of allocations based on TCC revenues, using Formula N-15. It is important to note that these numbers represent net annual allocations, which understate the allocation inefficiencies observable at more granular levels (e.g., hourly or constraint-specific).

Table 10: Category of Day-Ahead Congestion Residual Allocations
2021-2024

Year	Cong. Residual Allocation ($M)	
	Cost Causation	Formula N-15
2021	$122.4	$56.8
2022	$326.5	$57.4
2023	$62.5	-$4.1
2024	$29.9	-$32.8

In 2021 and 2022, significant N-15 shortfalls occurred primarily due to reductions in the Central-East interface limit caused by operational changes in nearby capacitors, static voltage compensators, and other transmission equipment modeled in the day-ahead market. Consequently, if TCCs are oversold across the Central-East interface due to changes in the status of certain equipment, one set of TOs receives the excess TCC revenues, while the resulting shortfalls are borne by a different set of TOs. This allocation method does not incentivize the efficient operation of transmission equipment.

N-15 surpluses have become more significant over the past two years, reaching nearly $33 million in 2024. We estimated hourly N-15 residuals for each transmission constraint and present them by month for major facility groups in Figure 26.

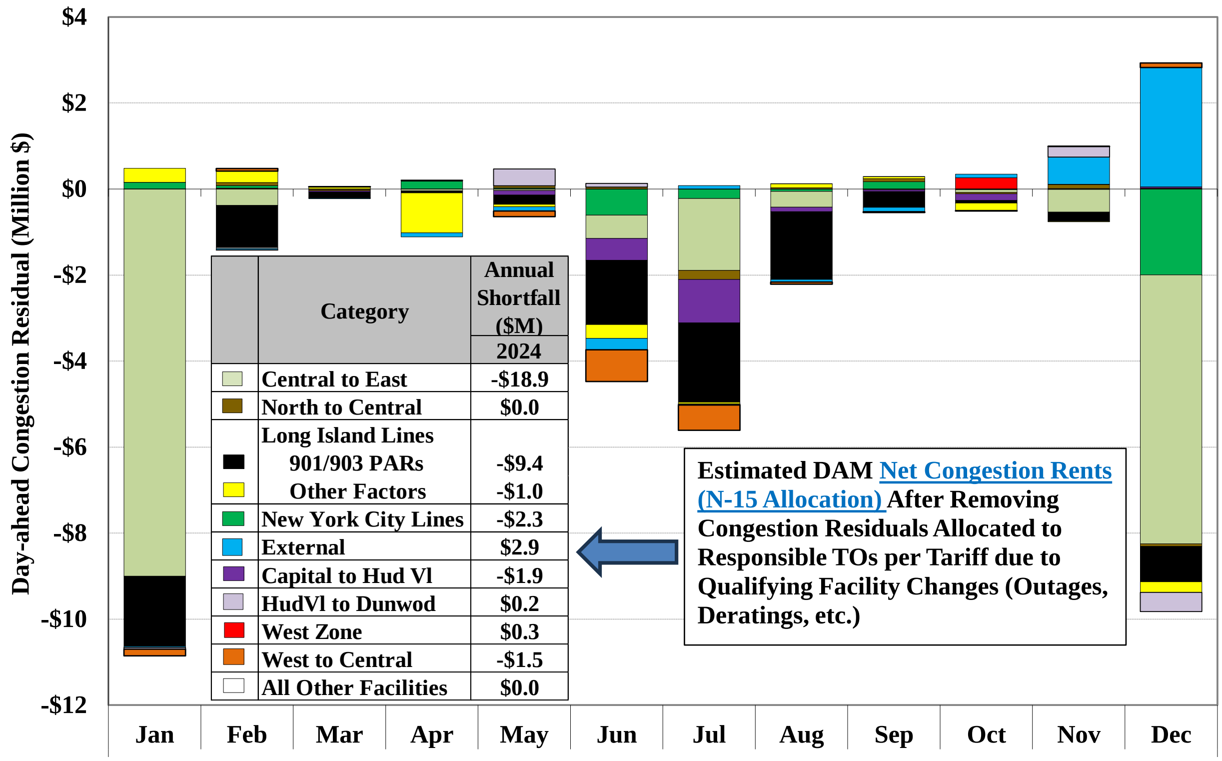
N-15 surpluses frequently accrue for interfaces that were constrained in the day-ahead market but that had been undersold in the TCC auction. Such congestion tends to result from changes in

108 For example, suppose a 100 MW line between nodes A and B is constrained: (i) from A to B for 200 hours at a shadow price of $5/MWh and (ii) from B to A for 150 hours at a shadow price of $5/MWh. The line will provide $17,500 of congestion revenue = 100 MW * 20 hours * $5/MWh + 100 MW * 15 hours * $5/MWh. However, the holder of a 100 MW TCC from node A to B (assuming a distribution factor of 100% for the TCC onto the line from A to B) will receive just $2,500 = 100 MW * 20 hours * $5/MWh *minus* 100 MW * 15 hours * $5/MWh. This results in a $15,000 revenue surplus, but the surplus is allocated to all TOs rather than just the owner of the line from node A to B.

the pattern of generation and load from day to day and hour to hour, which shift the pattern of congestion across the transmission network. Such variations accounted for a large share of N-15 surpluses on Long Island facilities in April and New York City facilities in June and December. This pattern is becoming more prevalent as intermittent renewable generation is added to the system. Hence, if TCCs are undersold across a particular interface due to shifting generation patterns, the surpluses are allocated across all TOs (in proportion to the TCC revenues) rather than to the TO whose equipment is enabling transfers across the network. As a result, TOs do not recoup the full value of their transmission assets when they are undersold in the TCC auctions, providing incentives to oversell transmission capability in the TCC auction.[109]

Figure 26: Estimated N-15 Residuals by Facility Group

By Month, 2024



Another significant type of N-15 surplus emerged from differences in flow assumptions on PAR-controlled lines between the day-ahead market and TCC auctions. Specifically, the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) generated over $9 million in N-15 surpluses in 2024. These lines consistently caused congestion surpluses because their assumed flows from Long Island to New York City were typically 300 MW in TCC auctions but significantly lower in the day-ahead market. Since these flows are generally

109 When a commodity is oversold in a forward market, it tends to depress forward prices relative to spot prices. Thus, it is likely that the oversale of TCCs tends to reduce overall collections of revenue by transmission owners.

uneconomic and raise production costs, reducing the scheduled flow from the TCC auction to the day-ahead market led to significant surplus congestion revenue. This also underscores that efficient scheduling the 901 and 903 lines would substantially reduce production costs.[110] Even though Con Ed has contractual rights to schedule these facilities, if Con Ed reduces the schedule of these facilities, leading to production cost savings and congestion revenue surpluses, most of these surpluses are distributed to other TOs.

A third type of N-15 surplus accrued on new transmission facilities. The new facilities associated with the AC Transmission Segment A and Segment B projects, as well as the Hurley Avenue Highway System Deliverability Upgrade project, were modeled as out-of-service in TCC auctions due to their eligibility for Incremental TCC awards. NYISO does not model such facilities as in-service in TCC auctions until the relevant Incremental TCC evaluation process concludes. However, these facilities were modeled as in-service in the day-ahead market, leading to congestion surpluses of more than $20 million in 2024. Again, these surpluses are allocated broadly among all TOs in proportion to TCC auction revenues, which does not align with the allocation of transmission upgrade costs.

In light of these inefficiencies, we recommend the NYISO revise the allocation of day-ahead congestion residuals that is currently socialized among TOs in proportion to TCC revenues rather than being assigned to the responsible TO. Instead, the allocation should be determined by changes in scheduled utilization of the transmission system between the TCC auctions and the day-ahead market. This adjustment would enable transmission owners to recover the value of transmission scheduled in the day-ahead market, even if the capacity was undersold in the TCC auctions.[111]

110 See Recommendation 2012-8.

111 See Recommendation 2023-1.

VIII. Capacity Market Performance

The capacity market is designed to ensure that sufficient capacity is available to satisfy New York's planning reserve margins. This market provides economic signals that supplement the signals provided by the energy and ancillary services markets to facilitate new investment, retirement decisions, and participation by demand response.

The capacity auctions set clearing prices for four locations: New York City, Long Island, a Locality for Southeast New York ("the G-J Locality"), and NYCA. By setting a clearing price in each Locality, the capacity market facilitates investment where it is most valuable for satisfying the NYISO's planning needs. This section of the report discusses the following:

- A summary of capacity market results in 2023 in Subsection A;
- Principles for setting efficient prices in the capacity market (Subsection B); and
- We recommend capacity market reforms in the following areas:
  - Defining additional pricing locations in the capacity market each year to capture emerging transmission bottlenecks (Subsection C),
  - Reforming capacity accreditation to ensure that supply resources are compensated efficiently as the resource mix evolves (Subsection D),
  - Compensating resources efficiently when locational capacity requirements are driven by transmission security limits (Subsection E),
  - Providing efficient capacity compensation to transmission investment (Subsection F), and
  - Reflecting seasonal capacity value in Subsection G.

A. Capacity Market Results in 2024

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices. Table 11 shows average spot auction prices for each locality for the 2024/25 Capability Year and year-over-year changes in key factors from the prior Capability Year. Table 11 shows that capacity prices rose in most regions primarily because of generator retirements. Changes in parameters such as the Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) also affect year-over-year capacity price trends.

A large amount of capacity in New York City retired in November 2022 and May 2023 due to the NYDEC Peaker Rule regulations. Reductions in UCAP from internal resources in 2024 were driven primarily by increased net exports to neighboring regions, higher EFORd values, and lower DMNC ratings of several resources. Surplus conditions in G-J Locality and Long Island led pricing in those regions being set by the systemwide curve throughout the year, except during

May – July in Long Island. In 2024, prices were driven down by a sharp drop in the systemwide load forecast and a lower LCR in New York City compared to the year prior.

Table 11: Capacity Spot Prices and Key Drivers by Capacity Zone[112]
2024/25 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2024 Margin (% of Requirement)	5.8%	16.4%	5.7%	11.7%
Net Change from Previous Yr	1.5%	7.9%	3.1%	-1.4%
Average Spot Price (Full Year)				
2024/25 Price ($/kW-month)	$3.47	$3.47	$11.76	$3.60
Percent Change Yr-Yr	-28%	-29%	-29%	-25%
Change in Demand				
Load Forecast (MW)	-507	-172	-72	-38
IRM/LCR	2.0%	-4.4%	-1.3%	0.1%
ICAP Requirement (MW)	150	-817	-204	-35
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-554	-182	-158	-180
SCR (MW)	-152	-73	-60	-7
Import Capacity (MW)	-7			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	-12%	-20%	-12%	-27%
Net Change in Derating Factor Yr-Yr	3.1%	2.3%	3.0%	1.4%

B. Principles for Efficient Locational Pricing for Capacity

Capacity markets should be designed to provide efficient price signals that reflect the value of additional capacity at each location. This will direct investment to the most valuable locations and reduce the overall capital investment necessary to satisfy the "one day in ten year" planning reliability standard. The current framework for determining capacity prices involves:

- Estimating Net CONE and creating a demand curve for each existing locality,
- Determining the amounts of capacity to be procured in each locality at the LOE using the "LCR Optimizer," and
- Setting the spot prices based on the locality's capacity margin and its demand curve.

In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the upcoming 2025/26 Capability Year. There are numerous combinations of LCRs that could satisfy NYISO's planning reliability criteria. The NYISO sets LCRs using the "LCR Optimizer" method, which is designed to minimize consumer payments while respecting (1) the 1-in-10 reliability standard, (2) the systemwide IRM, and (3) transmission security limits (TSLs) in each locality. Increasing the LCR in an area tends to reduce its marginal reliability value because

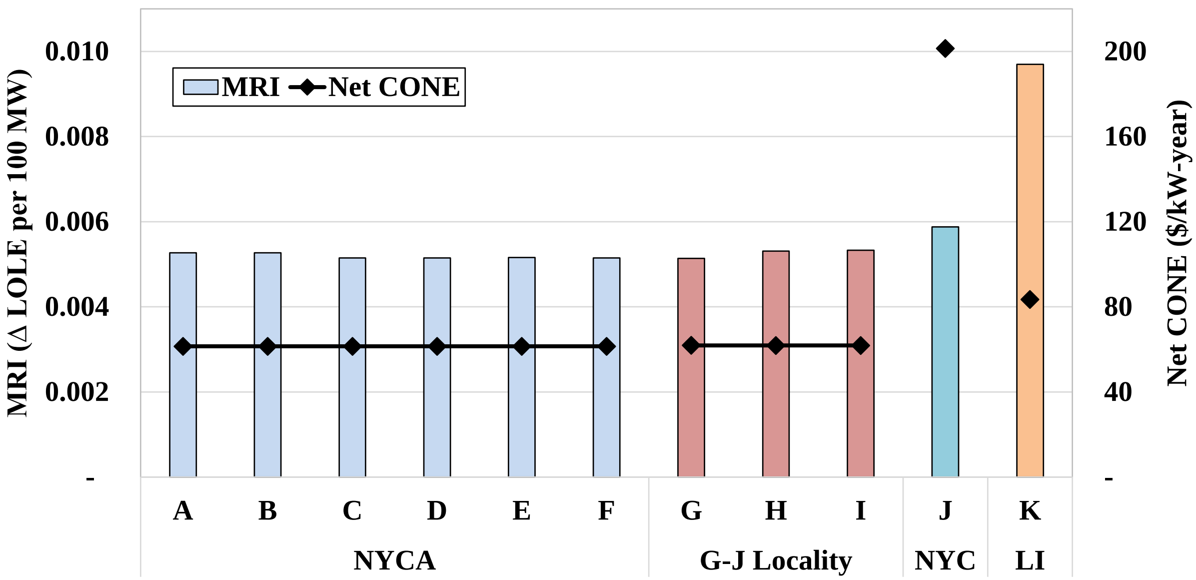
112 See Section VI.D in the Appendix for more details.

each additional unit of capacity provides diminishing benefits. In evaluating the performance of the capacity market, we define two values that quantify the costs and benefits of capacity:

- Marginal Reliability Impact (MRI) – the estimated reliability benefit (i.e., reduction in annual loss of load expectation (LOLE)) from adding some UCAP to an area.
- Cost of Reliability Improvement (CRI) – the estimated cost of adding an amount of capacity to a zone that improves the LOLE by 0.001. This is based on the estimated cost of new investment (Net CONE) from the latest demand curve reset study divided by the MRI of capacity in a particular location.

In an efficient market, the CRI should be the same in every zone under long-term equilibrium conditions (i.e. Level of Excess or "LOE"). If the CRI is lower in one zone than in another, cost savings would result from shifting purchases from the high-cost zone to the low-cost zone. Figure 27 and Figure 28 show the estimated MRI, Net CONE, and CRI for each locality and zone based on the 2025/26 Final LCR Case.[113]

Figure 27: Marginal Reliability Impact (MRI) and Net CONE by Locality and Zone
2025/2026 Capability Year at Level-of-Excess Conditions

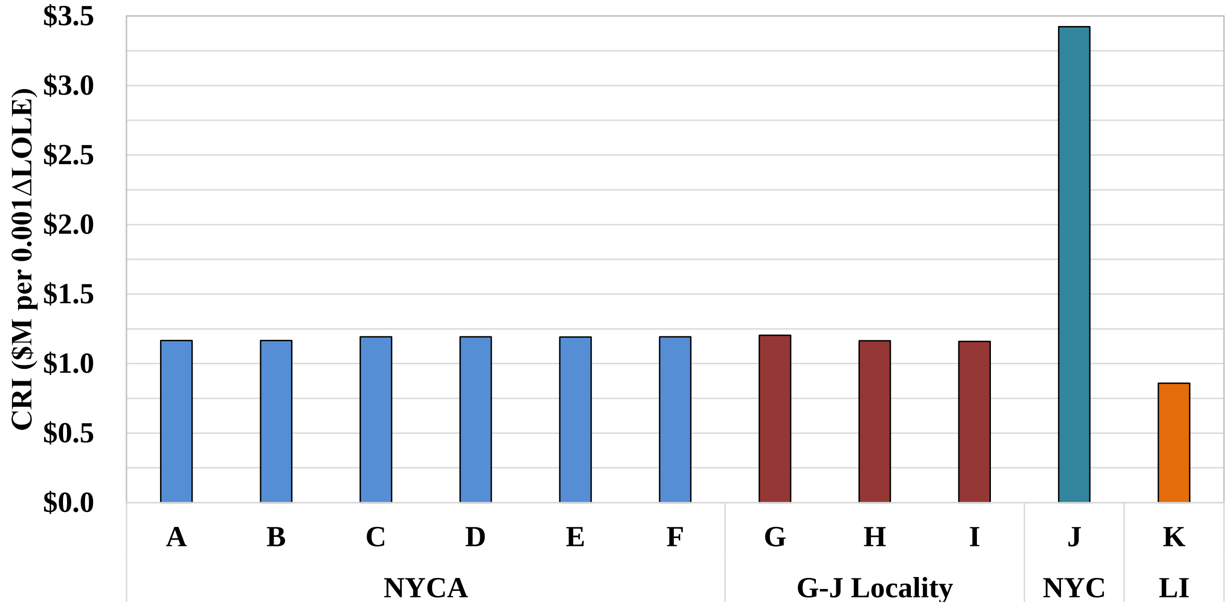


It is apparent from Figure 28 that the use of the Optimized LCRs Method does not result in equal CRI values across zones. The range between the minimum CRI location of Zone K (at $0.9 million per 0.001 events) and the maximum CRI location of Zone J (at $3.4 million per 0.001 events) is significant and indicates the requirements in some areas are inefficiently high or low. For example, the relatively low CRI in Zone K indicates that it would be efficient to place additional capacity there, suggesting that its LCR for the 2025/26 Capability Year (106.5

113 See Section VI.F of the Appendix for the methodology and assumptions used to estimate the CRI and MRI.

percent) is below the efficient level. The TSL-based floor does not prevent the Optimizer from selecting a higher LCR value for a locality.

Figure 28: Cost of Reliability Improvement (CRI) by Locality
2025/2026 Capability Year at Level-of-Excess Conditions



Several factors account for the inefficiency of prices in the capacity market:

Issues with LCR Optimizer: The LCR Optimizer uses an optimization objective function that is designed to minimize consumer costs from the perspective of a single buyer with market power rather than to the marginal capacity costs (i.e., investment costs), which has historically resulted in inefficient and overly volatile LCRs.[114] NYISO has been analyzing potential changes in the objective function to minimize investment costs but recently paused this effort.[115] We support development of an optimization approach that minimizes investment costs, but this must be done in conjunction with a more granular capacity zone framework (which is discussed later in this section) and consideration of appropriate Net CONE curves for use in the optimization. If the capacity zone framework is not sufficiently granular, transmission constraints may arise in the resource adequacy model that cannot be accounted for efficiently when the LCRs are set.[116] The

114 By minimizing overall consumer costs, the NYISO procures capacity like a monopsonist. Thus, the LCR Optimizer may shift purchases inefficiently from one area to another *because of* the resulting price effects. See discussion in Appendix VI.F of flaws in the Optimizer's objective function.

115 See NYISO presentation to March 6, 2025 Installed Capacity Working Group, available here.

116 For example, in some years, transmission constraints have limited flows into Zones A and B in the IRM and LCR studies, but the IRM/LCR study process cannot set minimum requirements specifically for Zones A and B. Rather, the only way that the IRM/LCR study process can satisfy the local needs of Zones A and B is by raising the statewide IRM by shifting capacity into Zones A, C, and D in a fixed proportion that includes a relatively small share for Zone A. Consequently, to resolve a relatively small need in Zones A and B, the

current inconsistency between the current 4-capacity zone configuration and the transmission constraints that bind in the resource adequacy model contributes to volatile and inefficient locational requirements.

The LCR Optimizer may also fail to set efficient LCRs because it is run after the IRM has already been determined. The LCR values are strongly affected by the IRM, which acts as a constraint in the LCR Optimizer which limits the range of possible LCR outcomes, but the range of possible LCRs may vary significantly from year to year.[117] As a result, changes to the IRM can cause volatility in the LCRs.

Overly Broad Pricing Zones: In recent LCR studies, we have observed MRI values for Zone G which are lower than for zones H and I, and lower MRI values for resources in Staten Island compared to the rest of New York City. This suggests that there are material differences in the reliability value of resources at different locations in the same capacity zones. Subsection C discusses improving locational capacity prices by defining more granular capacity zones to account for intrazonal transmission bottlenecks.

Impact of Transmission Security Limits: The LCRs for the NYC and the G-J Locality capacity zones were set at the minimum floors based on their transmission security limits (TSLs). While the high CRI in Zone J suggests it would be efficient to shift capacity to other zones, the Optimizer cannot reduce the Zone J LCR because doing so would violate the TSL-based minimum requirement. While the TSLs have in some cases led to inefficiently high LCRs, they have also prevented other problems with the LCR Optimizer from causing the LCRs to be set at extremely high or low values. The impacts of the TSLs are discussed further in Subsection E.

C. Defining Additional Pricing Locations in the Capacity Market

An efficient capacity market requires capacity zones that accurately recognize the system's ability to utilize generation in different areas. When transmission bottlenecks limit generation deliverability during tight hours, capacity prices reflect these bottlenecks to send more efficient investment incentives. This section discusses deficiencies with NYISO's current process for defining capacity zones and proposes a process to set more efficient locational capacity prices.

Issues with Current Zonal Framework

NYISO's capacity market consists of four pricing regions encompassing one or more load zones: New York City, Long Island, the G-J Locality, and Rest of State. The boundaries between these

IRM/LCR study process must move a much larger amount of capacity to Zones A, C, and D and from southeast New York.

117 This process is known as the "Tan 45" procedure. A description of this process can be found in the NYISO presentation to NYSRC on June 3, 2020 "Unified Methodology & IRM Anchoring Method", available here.

regions roughly capture the locations of historical transmission bottlenecks that limit capacity deliverability during summer peak periods.[118] NYISO performs a New Capacity Zone study every four years to examine whether new capacity zones should be created. This process has created a new capacity zone only once, when the G-J Locality was created in 2013. The existing zonal framework and new zone creation process suffers from several deficiencies:

- _Highway constraints not modeled_ – Generators in load zones that are separated by transmission constraints within an existing capacity region all receive the same price. For example, in recent LCR studies we have observed transmission bottlenecks within the Rest of State region (between zones A-B and zones C-F) and within the Lower Hudson Valley (between zone G and zones H-J). As winter demand grows, binding constraints will likely emerge across the Central East interface between zones A-E and zone F.
- _Byway constraints not modeled_ – Generators whose output is limited by transmission constraints within a load zone receive the full capacity price even when they are effectively not deliverable. For example, there are binding deliverability constraints between Staten Island and the rest of New York City, but Staten Island resources are paid the premium New York City price. Similarly, recent deliverability studies have found binding constraints between eastern and western Long Island.
- _Considers Only One Peak Load Scenario_ – The New Capacity Zone study will not lead to creation of new zones in many situations where bottlenecks are present. It relies on a deterministic study process that considers only one set of system conditions. As a result, it fails to detect deliverability constraints that bind in NYISO's probabilistic resource adequacy model. This inadequacy will grow as more intermittent and storage resources, whose output is not well represented by a deterministic snapshot, enter the market.
- _Barriers to New Investment_ – New resources attempting to enter potentially bottled areas may be assigned System Deliverability Upgrades (SDU) by the interconnection process. In recent years nearly all proposed new resources in certain areas have been assigned prohibitively costly SDUs (see IV.A). This system discourages new investment while protecting incumbent resources in bottled areas from competition. It also relies on deterministic assumptions that may inaccurately assess new resources' deliverability.

The impact of these shortcomings is to over-compensate resources in bottled areas and under-compensate resources in high-value areas, which drives up capacity prices and retains excess capacity in service. This is because the IRM and LCR processes compensate for the presence of bottled capacity in a sub-regional area by inflating ICAP requirements instead of limiting procurement in the bottled area. Legacy resources in bottled areas have incentives to not retire and to retain their rights to sell capacity, preventing new entrants from entering those areas.

118 Capacity deliverability broadly refers to the ability of generation to be delivered to load at times of peak system need. Assessments of deliverability examine whether the available generation in a region is simultaneously deliverable to load in a scenario where all generation is needed to avoid load shedding.

Overview of Proposal

We recommend that NYISO establish a dynamic process to update capacity zones used to set prices (Recommendation 2022-4).[119] This would expand the number of capacity zones and replace the existing zone creation process, while keeping the structure of the capacity market largely intact.[120] Its primary effect would be to: (1) discount capacity payments to export-constrained areas that are currently overpriced (such as Staten Island), and (2) allow for reliability needs to be efficiently reflected in prices as they emerge (for example, if bottlenecks in winter cause the value of capacity in zones A-E to fall relative to Zone F in the future). We discuss this proposed process for establishing capacity zones and requirements in this subsection:

1. Represent all major capacity deliverability bottlenecks in the resource adequacy model;
2. Designate capacity zones as import or export-constrained capacity zones based on the configuration of binding transmission constraints in the resource adequacy model;
3. Determine ICAP requirements for all import and export zones;
4. Establish import and export demand curves for use in the Spot Auction;
5. Apply a financial Capacity Constraint Pricing Credit or Charge to capacity payments of resources that positively or negatively impact aggregate deliverability between regions.

1. Represent all major deliverability bottlenecks in the resource adequacy model

NYISO's resource adequacy model GE-MARS is a probabilistic simulation of load shedding risk that accounts for transmission limits between regions. It is used in the IRM and LCR studies to determine the ICAP Requirements in the capacity market. The representation of the NYCA region in the IRM and LCR studies includes areas based on the eleven historic load zones (zones A-K) with transmission limits between them.[121] In reality, there are also internal bottlenecks

119 In this subsection, a "capacity zone" refers to a pricing zone with a capacity market demand curve (such the NYCA and G-J Locality zones), a "region" refers to a part of a capacity zone that may have a distinct price (such as the Rest of State and GHI regions within the NYCA and G-J Locality), and an "area" refers to a part of the system that is separated from other areas by transmission bottlenecks. Areas are represented as "bubbles" in the GE-MARS topology and include (but are not limited to) the 11 historic load zones (A-K).

120 We have also recommended that NYISO implement Locational Marginal Pricing of Capacity ("C-LMP"). (Recommendation (2013-1c). Under this approach, prices would be set based on the Marginal Reliability Improvement (MRI) of capacity at each location, without the need for an ICAP Requirement or demand curve. In the long term, this approach will better adapt to changing system conditions and be simpler and more transparent, since it would greatly reduce the number of administrative parameters that influence capacity market outcomes. For a discussion of C-LMP, see Section I and Section VIII.E of our 2022 Report on the NYISO Markets, available here. The recommendation for more granular capacity zones (2022-4), which is discussed in this section, achieves many of the benefits of C-LMP but does not comprehensively revise the existing capacity market structure.

121 Transmission limits between Staten Island and New York City are modeled indirectly by a dynamic limit on PJM imports to Zone J via the "J3" area.

within the load zones that limit deliverability of capacity. For example, recent deliverability studies indicate that binding export constraints exist in Staten Island and eastern and central Long Island, with deliverability headroom tightening in other areas. New intra-zonal constraints may arise over time and pricing capacity in these areas efficiently requires that they be represented in the resource adequacy model so the bottled capacity can be quantified.

Hence, the annual process used by NYISO and NYSRC to update the transmission topology for the IRM study could identify intra-zonal capacity bottlenecks based on power flow simulation and represent those constraints in GE MARS. New constraints could be represented by modeling additional areas in MARS with transmission interfaces between adjacent areas. Not all constraints detected this way will lead to binding constraints in MARS since the probabilistic outcomes of MARS will differ from a deterministic power flow assessment.[122] It may be necessary to establish a threshold for representation of a new area in MARS so that only bottlenecks that affect a significant amount of capacity are represented.

2. Designate capacity zones as import or export-constrained based on configuration of binding constraints in the resource adequacy model

After the previous step identifies individual capacity zones and transmission interfaces, individual zones can be classified as either import or export zones:

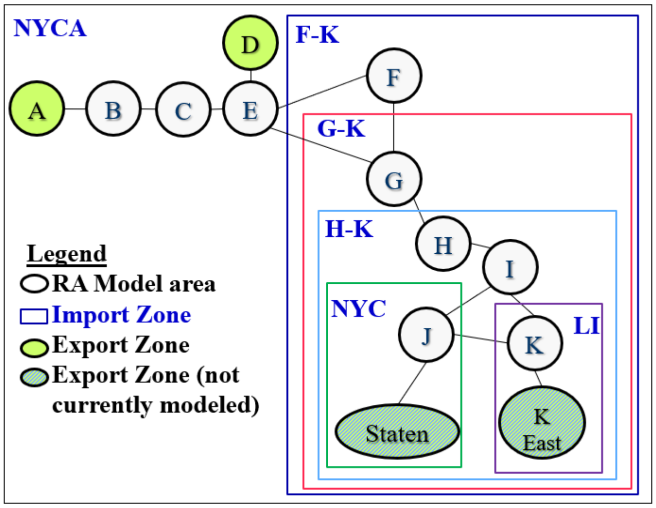
- An import zone consists of one or more areas whose ability to import capacity is constrained during all or some hours of reliability risk. Import zones would function like NYISO's existing capacity zones and could be nested within other import zones. For example, a constraint on the UPNY-CONED interface between zones H and G could lead to an import zone within the existing G-J locality consisting of zones H-J.
- An export zone is an area that has surplus capacity facing export bottlenecks to a "parent" region. When exports from an area to its parent region are constrained in MARS, an export zone should be created. Each export zone would be nested inside of an import zone. The process for compensating capacity in these zones is discussed further below.

Figure 29 provides an example capacity zone topology under our proposal. It shows potential import and export capacity zones following completion of the Long Island PPTN transmission projects. Compared to today's capacity zones, the G-J Locality is expanded to include Zone K due to increased transfer limits within this area following the Long Island PPTN. New import zones are created downstream of the Central East (F-K) and UPNY-CONED (H-K) interfaces. Within the Rest of State region, export zones are created in western and northern New York. Finally, new areas not currently modeled directly in MARS are created in Staten Island and eastern Long Island, which lead to creation of export zones within the existing NYC and Long

122 A difference in the value of capacity between zones can be observed by calculating the Marginal Reliability Impact (MRI) of each zone when the system is modeled at the target reliability criteria. A difference in MRI between zones indicates a binding transmission constraint between those zones.

Island import zones. This arrangement of potential import and export zones is illustrative, and new or different zones could be created depending on the location of deliverability bottlenecks.

Figure 29: Illustration of Import and Export Zones After LI PPTN Projects In Service



This process would largely eliminate the need to assign mandatory SDUs to new projects seeking CRIS. Instead, all resources in a bottled region receive lower capacity prices reflecting the value of capacity in that region. Informational studies could be regularly conducted by NYISO to inform developers of potential new zones likely to emerge in the coming years based on the locations of projects in the interconnection queue. Developers entering bottled regions could elect to fund transmission upgrades and earn financial rights allowing them to benefit from the capacity value of the upgrades (see Recommendation 2012-1c and Subsection F).

3. Determine ICAP Requirements for all import and export zones

NYISO would continue to use the LCR Optimizer to establish LCRs for each import zone while satisfying the minimum TSL-based floors.[123] This method implicitly accounts for both the cost and the marginal reliability benefit of procuring capacity in each region as the amount procured changes. As a result, the optimized LCRs will maximize procurement in lower-cost regions until transmission constraints begin to limit the effectiveness of capacity there.

Under this process, the ICAP Requirements of import zones would represent the targeted minimum amount of capacity to be maintained in that zone. For export zones, the ICAP Requirement would represent the maximum amount of capacity that would be fully deliverable to the parent zone.[124] The requirements of export zones would be set such that any additional capacity will cause the export constraints to bind during critical hours in MARS.[125] The requirements of export zones would be included in the requirements of the parent import zone.

123 The NYCA IRM is currently determined prior to the LCRs by the NY State Reliability Council (NYSRC) using a different process from the LCR Optimizer. It would be more efficient to determine the IRM and LCRs simultaneously using the LCR Optimizer, but this is not necessary for Recommendation #2022-4.

124 To determine the amount of fully deliverable capacity, the LCR Optimizer would use a modest (~5 percent) discount on the cost of supply in the export-constrained zone. Thus, the export-constrained zone would not need its own Net CONE estimate.

125 This implies export zone capacity should have an MRI very close to that of the parent zone when capacity is equal to the requirement, and a declining MRI relative to the parent zone if additional capacity were added.

4. Establish import and export demand curves for use in the Spot Auction

Currently, the capacity market's spot auction is cleared using demand curves that are designed to encourage new entry when capacity in a zone approaches that zone's requirement. Under our proposal, this process would remain largely unchanged for import zones. Each import zone would clear based on its own demand curve, and each supplier would receive the highest clearing price among import zones to which it belongs.

In the current framework, certain key demand curve parameters including the net cost of new entry (Net CONE) and demand curve length are determined in the Demand Curve Reset (DCR) process every four years. This process may not anticipate every import zone and determine parameters for it. Hence, it will be necessary to: (1) determine Net CONE values for a set of locations and use the Net CONE value of the "parent" zone for any new import zone that is created before the next DCR, and (2) establish a process to automatically determine demand curve lengths for new zones based on the marginal reliability impact (MRI) of surplus capacity.

For export zones, we recommend creating export zone demand curves whose purpose is to discount payments to resources in bottled areas. Each export zone demand curve would determine the percentage of the parent zone's price to be paid to resources in the export zone, as a function of the export zone's capacity surplus. Hence, export zone demand curves would not require a separate Net CONE estimate. Capacity in the export zone that is fully deliverable during critical hours should be counted towards the requirement of the parent zone when clearing the auction, and partially deliverable capacity should be counted on a discounted basis.

Figure 30: Export Zone Demand Curve

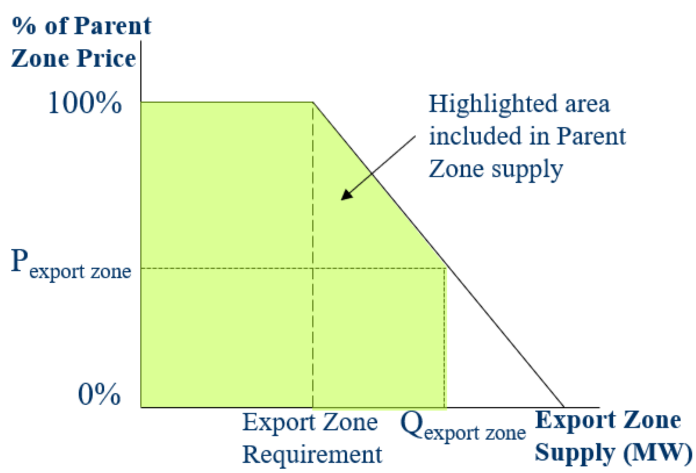


Figure 30 illustrates this concept. When capacity in the export zone is less than or equal to the export zone requirement, payments are equal to the parent zone price because all of the export zone's capacity is deliverable. Surplus beyond the export zone's requirement causes the price paid to fall as a percentage of the parent zone price. The export zone demand curve has a slope because export zone capacity may be bottled in some, but not all hours when surpluses are modest. The area under the export zone demand curve (which counts all capacity up to the export zone requirement and discounts any surplus) is then counted as supply towards meeting the import zone's requirement.

5. Apply a Capacity Constraint Pricing (CCP) component to capacity payments of resources that positively or negatively affect transmission limits between zones.

Each resource in a capacity zone is currently paid the same capacity price even though not all resources within a zone contribute equally to loading of constraints affecting that zone. Hence, we propose a financial Capacity Constraint Pricing Credit or Charge that modifies the capacity payments of resources that increase or decrease the total amount of capacity deliverable over a binding constraint. These variable effects of different resources on the constraint are reflected in their generation shift factors (GSFs). For example, generation added in an export-constrained area at a bus with a very low or negative GSF on the constrained facility may increase the total deliverable capacity by displacing other resources with higher GSFs on the constraint.[126]

Efficient prices reward investment at locations that improve deliverability and discourage investment at locations that diminish deliverability. We propose NYISO apply a CCP credit or charge to reward or penalize resources that modify a zone's import or export limit. We propose the following process:

1. Calculate a set of generator CCPs for each interface between capacity zones (e.g., between two nested Import Zones or between and Import and Export zone). The CCP Factor is the amount by which an additional MW of output at a generator's location would change the total deliverable capacity, either positively or negatively. The CCP Factors are specific to each interface between zones.
2. Calculate the price difference across each interface between nested capacity zones. This is the difference in capacity price between the capacity zones connected by the interface.
3. Each generator earns a total capacity payment equal to its UCAP MW times the sum of the zonal Capacity Price and generator's unique CCP Credit/Charge.

Section VI.G of the Appendix includes an example of the calculation of CCP Factors and generator payments. The CCP Credit/Charge would produce substantial benefits by providing much more accurate locational incentives in each capacity zone. This is key because generators in any fixed capacity zone will have different effects on key constraints. It will also mitigate issues that arise when new capacity zones are not created to reflect key deliverability constraints.

6. Conclusions Regarding the Granular Capacity Zones Proposal

The current zonal structure of the capacity market does not capture important distinctions in the value of capacity by location and will become increasingly disconnected from the needs of the system over time. As a result, the capacity market will send inefficient signals for investment and retirements and the flawed deliverability process will continue to be a major barrier to new investment in certain locations. In this subsection, we have proposed a process to define new

126 In situations where the GSFs do not accurately approximate generators' impact on the relevant constraint, such as for voltage-based transfer limits, other methods may be used.

capacity zones that will better signal where additional capacity is and is not valuable. In particular, this proposal will:

- Avoid over-compensating resources in bottled areas and facilitate retirement of non-deliverable capacity;
- Reduce capacity costs because LCRs will not rise to compensate for bottled capacity; and
- Attract and retain capacity in locations where it is more valuable to the system.

D. Improving the Capacity Accreditation of Individual Resources

Capacity accreditation refers to the value of a resource's installed capacity relative to perfect capacity when it is sold in the capacity market. It is intended to reflect the likelihood that the resource will be available when needed for reliability. This subsection discusses methods to establish capacity credit in NYISO and proposed enhancements.

Status of NYISO Capacity Accreditation Reforms

Transactions in the capacity market are denominated in UCAP terms, so NYISO applies methods for converting the installed capacity (ICAP) value of each resource to UCAP. Before May 2024, these conversion methods relied on simple heuristics that did not accurately reflect the marginal reliability impact of each resource type. For example, the UCAP of an intermittent resource was calculated based on its average output in a range of hours each day, which is not necessarily when supply is tightest. As a result, the UCAP ratings of some resources were inflated.

In May 2024, NYISO began to use UCAP values based on marginal accreditation principles. Under the new rules, NYISO establishes a Capacity Accreditation Factor (CAF) for each Capacity Accreditation Resource Class (CARC) reflecting its marginal contribution to reliability (e.g., its expected availability during hours when load shedding is most likely). CAFs will be updated annually and for each capacity market region.[127]

These changes are a major improvement to the capacity market. Aligning resources' compensation with their marginal contribution to reliability is necessary to encourage efficient investment in a diverse resource mix, which is discussed in more detail in Appendix VI.I.

Enhancements to Capacity Value Modeling

Notwithstanding these improvements, additional enhancements will be needed to address key challenges in the coming years. NYISO calculates CAFs using its resource adequacy model, MARS, which is a Monte Carlo model that simulates resource availability under a variety of conditions. MARS is limited in its ability to model the following types of resources:

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127 See https://www.nyiso.com/accreditation for information on capacity accreditation factors.

- *Resources with Winter Fuel Limitations* – Some generators can only burn natural gas and often face fuel supply restrictions during very cold winter weather. During these periods, NYISO relies heavily on generation by oil-fired and dual fuel resources, which have limited stored fuel inventories. Winter fuel limitations of gas-only and dual fuel resources have not previously been modeled in MARS, but NYISO has recommended that NYSRC adopt them in the 2026-27 IRM Study, which would enable NYISO to calculate distinct CAFs for the firm fuel and non-firm fuel CARCs and, thereby, provide financial incentives for firm fuel capability.[128] NYISO's proposal to include fuel limitations in MARS is a major improvement. As winter risk grows, further improvements will be needed to ensure that the contributions of all resource types towards winter reliability are properly modeled and reflected in CAFs. In particular, the currently proposed approach will not result in CAFs for energy storage resources that are consistent with those of resources with limited fuel inventories. It will also undervalue the winter reliability contributions of intermittent renewables that defer the need for consumption of stored fuel during non-critical hours.[129]
- *Load-Correlated Resources* – MARS models hourly load patterns independent of resource availability. However, factors such as weather may affect both load and availability of some resources. If solar generation and load are not appropriately correlated in the model, solar and other resources will be valued inaccurately. Aligning the modeling of resources and load profiles to reflect common drivers would improve capacity value estimates. NYISO is currently developing improvements to better correlate load and BTM solar output.[130]
- *Energy Storage* – Modeling realistic dispatch of energy limited resources (ELRs) is challenging because it must balance the objective of discharging optimally with the limitations of foresight. NYISO recently adopted an approach in which ELRs are dispatched to avoid load shedding prior to Emergency Operating Procedures ("EOPs" such as deployment of SCRs and reserves) but may only discharge in a predetermined set of hours.[131] This approach should be refined so that:
  (a) a portion of storage capacity is withheld until reserve deployment EOPs, representing a more optimal and realistic usage, and
  (b) remaining 'peak shaving' storage is targeted to periods when shortages are most likely, reflecting strategic behavior with imperfect foresight.[132]

128 See summary of latest proposal here.

129 See Section VIII.G of our 2023 State of the Market Report for the NYISO Markets, available here.

130 See NYSRC IRM Model Proposed Whitepaper Scopes 2025, presented by NYISO to NYSRC Installed Capacity Subcommittee on January 8, 2025, available here.

131 See October 7, 2021 presentation to NYSRC *Sensitivity Using GE MARS in Modeling ELRs*, available here

132 See our comments on NYISO's 2019 storage capacity value study, available here.

NYISO should also determine whether the sequencing of external assistance EOPs in MARs results in unrealistic timing of ELR dispatch. NYISO plans to consider improvements to ELR modeling in 2025 and 2026.[133]

- *Inflexible Resources* – Inflexible units, such as steam turbines with long startup lead times, provide less reliability value than more flexible units because they may not be available when needed. However, MARS treats these units as always committed and available if not in outage. Hence, the capacity of these units is likely to be overvalued as net load uncertainty increases due to rising deployment of intermittent resources.

Hence, we recommend that NYISO and NYSRC consider improvements to more accurately evaluate marginal reliability contributions for: (a) gas-only generators with limited/no backup fuel, (b) inventory-limited resources, (c) duration-limited resources, (d) resources whose availability is correlated with load, and (e) inflexible generators. (see Recommendation 2021-4)

Functionally Unavailable Capacity

NYISO tests the Dependable Net Maximum Capability (DMNC) of each generator on a seasonal basis. This test is intended to rate each generator's maximum output when not experiencing a forced outage or derating during temperature conditions comparable to the expected peak load period of each season. The ICAP that a resource can sell in the capacity market is determined based on the lower of its DMNC and capacity interconnection rights (CRIS) quantity. NYISO has generally over-estimated the ICAP of fossil-fuel and nuclear resources with the following characteristics:

- *Emergency Capacity*: Capacity offered above a generator's normal upper operating limit (UOLn) that is only activated under NYISO Emergency Operations.[134] Operators may not commit this capacity in practice because of concerns that the emergency capacity cannot operate in a reliable manner, thereby increasing the risk of outage to the normal range of the generator's capacity.[135]
- *Ambient Water Temperature Dependent*: Generators that have once through water-cooled condensers experience diminished cooling capability as inlet water temperatures rise. Environmental restrictions also prohibit outlet water temperatures from exceeding defined thresholds. Therefore, many of these water-cooled units have reduced capability on hot summer days due to higher water temperatures.

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133 See NYSRC IRM Model Proposed Whitepaper Scopes 2025, presented by NYISO to NYSRC Installed Capacity Subcommittee on January 8, 2025, available here.

134 See NYISO Emergency Operations Manual.

135 For example, if a 100 MW generator with 10 MW of emergency capacity has a 5 percent outage risk on the non-emergency range (i.e., the first 90 MW), then the effective UCAP of that capacity would be 85.5 MW (i.e., 95% of 90). If operating in the emergency range increases the outage risk of the facility to 15 percent, the true reliability value of the plant would be 85 MW, implying that the marginal value of the emergency capacity is *negative* 0.5 MW.

- *Tidal Dependent*: Generators with once-through water-cooled condensers pulling water from tidal dependent sources (i.e., the southern regions of the Hudson River Estuary and Coastal regions) are also likely to see their capabilities rise and fall with changing tidal conditions due to variations in cooling water flow and pressure.
- *Relative Humidity Dependent*: Combustion turbines that are equipped with certain Inlet Cooling Systems are significantly impacted by increases in the relative humidity in the air. This impact increases as air temperatures rise, compounding this issue.
- *Barometric Pressure Dependent*: Combustion turbine efficiency and capability is impacted by barometric pressure in a predictable manner. This relationship is positively correlated, i.e., turbine capability increases with higher pressure conditions (and decreases as pressure drops) because air density impacts mass flow through the turbine. This impact is predictably greater at summer peak load conditions since those correspond to the warmest weather days and hot air is less dense than colder air.
- *Cogeneration & Steam Demand*: Some units have reported derates from cogeneration units due to limitations associated with their host steam demand. Some resources in this category may sell capacity to NYISO without accounting for the full contractual obligations to their host steam demand.

NYISO has begun to address issues with cogeneration capacity through improved DMNC test and approval procedures. In addition, the NYISO made changes to procedures to address some issues outlined above starting in May 2025.[136] The proposed changes will appropriately account for relative humidity effects, but will only partially address water temperature dependent (including tide dependent) resources and emergency capacity.[137] Furthermore, investigations into observed underperformance from several resources during the 2024 summer peak periods, mostly combined cycle generators, identified barometric pressure as a significant driver of functionally unavailable capacity as well. The issue arises mainly from the fact that generators typically perform DMNC tests at the most favorable weather conditions possible, typically mild temperature, clear, sunny days in early or late summer. Barometric pressure is much higher on those types of days than on the typical peak load-type day at warmer air temperatures. Therefore, we have recommended that barometric pressure be added to the ambient-conditions output adjustment for all generators with one or more combustion turbine.

NYISO eliminated the Capacity Limited Resource (CLR) designation and will require such units to offer the ICAP equivalent of the UCAP sold at the normal upper operating limit (UOL_N)

136 See Management Committee presentation from March 27, 2024.

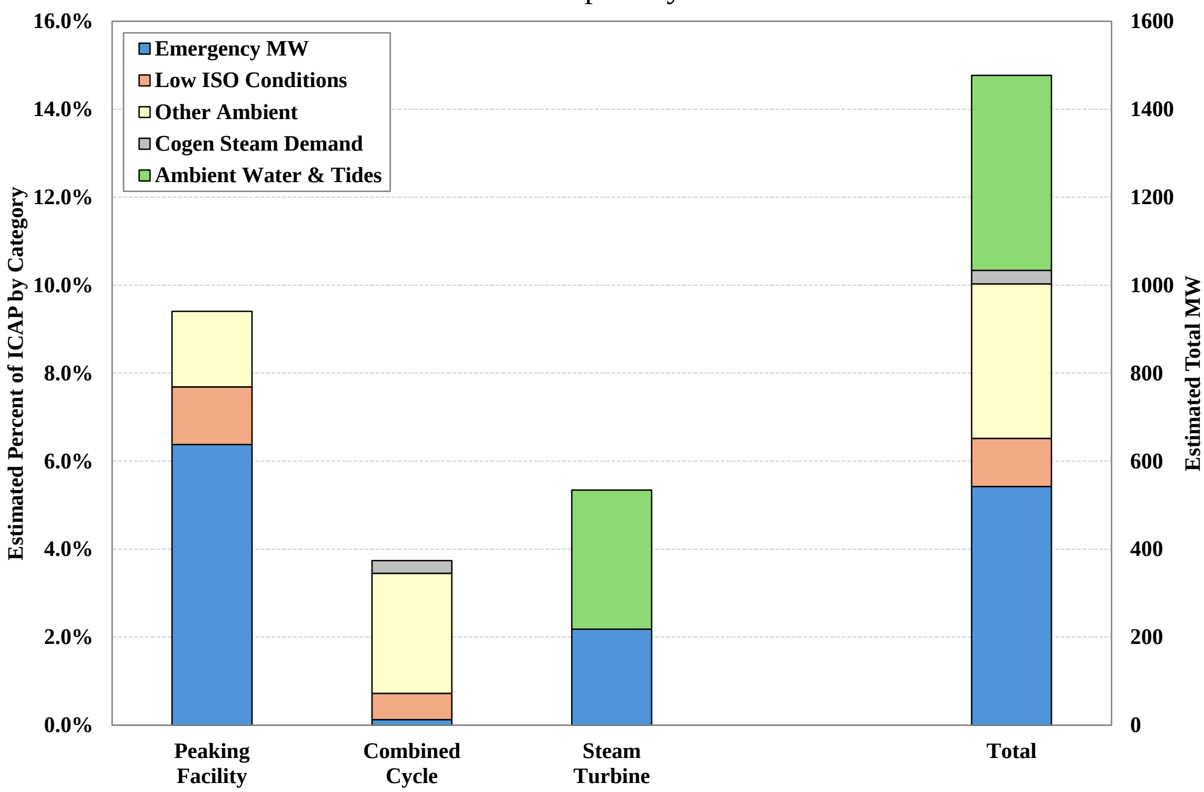
137 The NYISO's proposal for addressing water temperature dependent resources simply requires these generators to test in July or August between the hours of 10 AM and 10 PM. However, these timing restrictions do not address: (i) tidal effects, or (ii) the effect of multiple units at a station operating concurrently. We observe that DMNC tests of these generators are usually conducted for one unit at a time during high tide conditions, leading to higher output levels than are achievable during peak summer conditions. This assumes that most participants will test their generators individually at high tide conditions, as has been characteristic in the past. See slide 87 of the 2023 Third Quarter State of the Market Report.

beginning with the 2025/26 Capability Year. This ought to reduce the sale of emergency capacity.[138] We will evaluate the effects of this change on capacity sales and system operations. One concern is that units operating in these ranges may have a higher risk of forced outage that may not be reflected in their EFORd.[139]

Figure 31 shows the estimated ICAP that was functionally unavailable to the market during peak conditions last summer on fossil-fuel and nuclear units by category.[140] Approximately 1,480 MW of ICAP was functionally unavailable on the hottest days, including an estimated 142 MW from combined cycle and peaking units due to higher barometric pressure at high loads than during actual DMNC tests for these resources.

Figure 31: Functionally Unavailable Capacity from Fossil and Nuclear Generators

Summer Capability Period



While NYISO has already implemented or filed changes that will address much of the capacity affected by the issues above, we recommend (see 2021-4) the following additional changes to DMNC testing and ICAP qualification processes:

138 This exempts combined cycle units with duct firing until the completion of the "Modeling Improvements for Duct Firing" project and for block loaded GTs that can operate in peak or normal firing modes.

139 See Appendix Section VI.C.

140 See Section VI.C of the Appendix for details and assumptions underlying this figure.

- Calculate seasonal capacity ratings that are adjusted for ambient water temperatures and tidal conditions (in a similar procedure to what NYISO currently uses to adjust for ambient air conditions) for affected generators.
- Quantify the UCAP value of emergency capacity based on its marginal value of capacity determined by the Equivalent Forced Outage Rate of this range.
- Require cogeneration resources to be seasonally rated in a manner similar to Behind the Meter Net Generation (BTM:NG) resources, which takes into account host steam obligations during peak load conditions.
- Require stations with one or more combustion turbines to adjust for differences between barometric pressures during DMNC tests and expected conditions at the forecasted peak load.

E. Impact of Transmission Security Limits on Efficient Capacity Payments

The LCR Optimizer employs a minimum ‘floor’ value in each locality based on the Transmission Security Limit (TSL). In recent years, LCRs have increasingly been set at this ‘TSL-floor’. When this occurs, the capacity market does not efficiently compensate resources that do not contribute to satisfying transmission security needs. In addition, the capacity demand curves may set inefficiently high prices when there is surplus supply above the TSL-based LCR.

The TSL-floor is enforced in the “LCR Optimizer” to ensure that LCRs do not violate NYSRC/NPCC transmission security criteria. Transmission security analysis differs from the resource adequacy analysis used by the LCR Optimizer because: (1) transfer limits are calculated more conservatively in the transmission security analysis, and (2) peak load and resource availability are modeled on a deterministic basis as opposed to stochastically.[141] As a result, the capacity needed to comply with transmission security criteria in a locality can exceed the amount needed to satisfy reliability criteria in GE-MARS. In this case, the LCR is set by the TSL-floor.

In NYISO’s planning studies, some resource types are assumed to contribute less towards transmission security requirements than resource adequacy requirements.[142] In particular:

- Special Case Resources (SCRs) contribute 0 MW towards transmission security requirements because they are assumed to not be available under normal transfer criteria.

141 For example, in the 2023 LCR Case, the MARS transfer limit between zones I and J was 4,400 MW, but the Zone J transmission security limit was 2,875 MW. For a detailed discussion of the differences between transmission security and resource adequacy analyses, see NYISO June 30, 2021 presentation to ICAPWG “Transmission Security Best Practices”, available here. For an analysis of the drivers of difference between TSL-based and Optimizer-based LCRs, see MMU Comments on the NYISO’s 2023-2032 Comprehensive Reliability Plan, available here.

142 See our review of NYISO’s 2022 Reliability Needs Assessment (RNA), available here.

- Large resources can increase the transmission security requirement, which is intended to maintain reliability in the event that the largest two generation and/or transmission elements are lost.[143]

NYISO has recently made changes to the calculation of the TSL-floor used in the LCR Optimizer to align it with the transmission security methodology used in its Reliability Planning Process.[144] The current methodology, which was used for the first time in the 2023/24 LCR Report, determines the TSL-floor as the local installed capacity needed to meet peak load considering resource unavailability based on expected forced outage rates while respecting the TSL. Since SCRs do not contribute to satisfying transmission security criteria, the current methodology raises the TSL-floor by the amount of expected SCR capacity sales in the locality.

Figure 32 illustrates the impact of recent changes in the TSL methodology. It compares the final LCRs and TSL-floors in the New York City locality for the 2019/20 through 2025/26 capability years, along with estimated TSL-floors for the 2026/27 capability year. The impact of the Ravenswood 3 unit on the TSL-floor is shown in all years. The impact of SCRs on the TSL-floor is shown beginning in 2022, when it was first affected by SCRs.[145] The 1,250 MW Champlain Hudson Power Express (CHPE) project is expected to raise the TSL-floor by 532 MW in 2026 because it will be the largest contingency in New York City.[146] We also show the projected historic New York City LCRs estimated as part of the annual IRM Study process. While these LCRs are not used in the capacity market, they were historically correlated with changes in the Optimizer-produced LCRs and may provide an approximate indication of LCR levels in the absence of binding TSLs.

Figure 32 illustrates that the TSL-floor is increasingly likely to determine the New York City LCR. The NYC LCR has been set at its TSL-floor every year since the adoption of the current methodology in 2022. In that time frame, the TSL-based LCR has exceeded the IRM Study LCR by 2.9 to 7.7 percent. After the CHPE line enters service, our projected 2026/27 TSL-floor further increases by 4.8 percent. TSL-floors lead to higher costs by requiring a larger amount of capacity to be held in higher-priced zones.

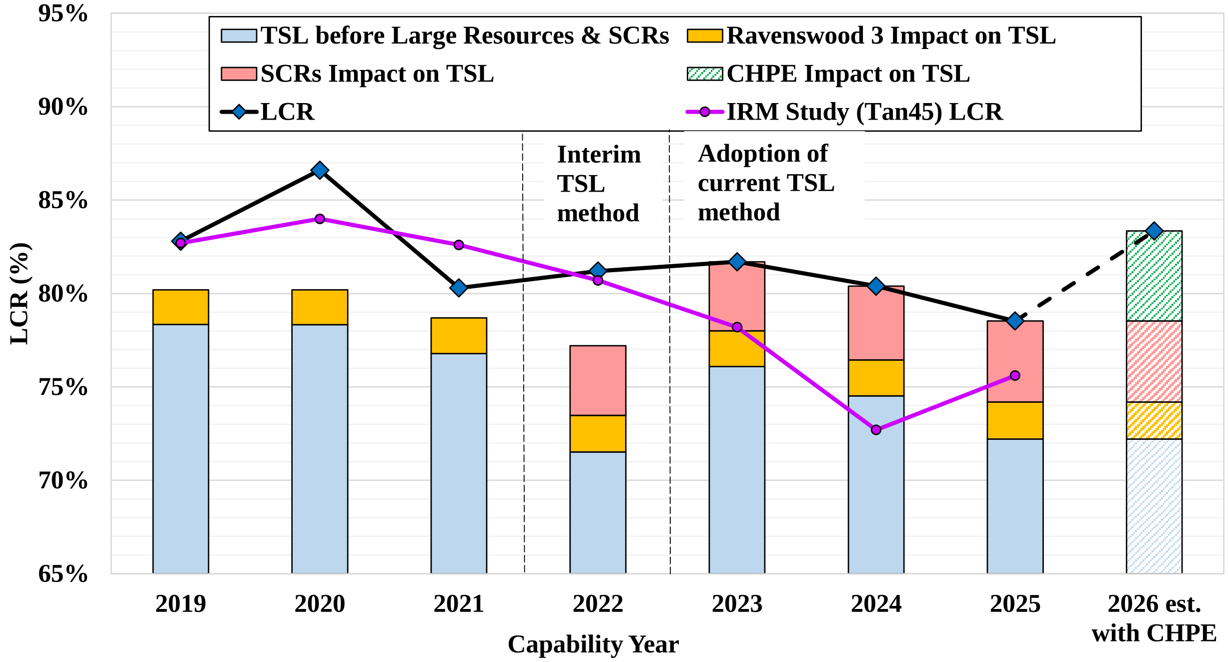
143 See our review of NYISO's 2020 RNA, available here, that showed that estimated that the 980 MW Ravenswood 3 unit in New York City increased transmission security needs by approximately 215 MW.

144 See NYISO October 4, 2022 presentation to ICAPWG on the TSL calculation for 2023, available here.

145 In the 2022/23 capability year, NYISO used an "interim methodology" that added back the capacity of SCRs when calculating the TSL-floor but did not convert the UCAP-based requirement into an ICAP quantity.

146 See Figures 78-84 in Appendix F to NYISO's 2022 RNA, available here, and our review of NYISO's 2022 Reliability Needs Assessment (RNA), available here.

Figure 32: Historical and Projected New York City LCRs and TSLs



The capacity market is designed to attract and retain capacity needed to satisfy planning reliability criteria. It is appropriate to set LCRs based on TSLs because, otherwise, a shortfall relative to the TSL would likely trigger a regulated procurement of capacity through NYISO's Reliability Planning Process. However, LCRs based on TSL-floors will lead to inefficient capacity market compensation for two reasons that are discussed further in this subsection. First, some resources receive capacity payments but do not contribute to satisfying transmission security requirements. Second, existing capacity market demand curves overvalue surplus capacity when requirements are set by TSL-floors.

1. Overcompensation of capacity that does not contribute to transmission security

Large resources and SCRs are overcompensated when the LCR of their locality is set at its TSL-floor. This is because the presence of these resources causes the TSL-floor to increase, so they provide less net supply towards meeting capacity requirements than they are paid for in the capacity market. This results in (1) higher consumer costs because these resources are paid more than the value they provide, and (2) inefficient investment incentives, such as for SCRs to convert to NYISO's DER resource type, which has different requirements and provides more value towards transmission security needs. In the 2024/25 Capability Year, we estimate that large resources and SCRs in New York City were overcompensated by up to \$46 million.[147]

147 This value reflects an upper-bound overpayment using the Tan 45 LCR of 72.7 percent as the assumed prevailing LCR in the absence of the TSL. We apply the corresponding difference in projected capacity prices to 479 MW summer and 243 MW winter SCR ICAP times the final four hour ELR CAF of 68.8

Hence, we recommend paying resources for capacity based on the requirements which they contribute to meeting (Recommendation 2022-1):

- SCRs should be compensated at the price that would prevail in their locality absent the TSL-floor. This will require the NYISO to determine what the LCR would be if there was no TSL requirement so that it can determine a resource's contribution to satisfying resource adequacy needs.[148]
- Large resource that increase the size of the contingency used to determine the TSL-floor should be compensated at two rates: the full capacity price for the portion of their capacity that does not cause the TSL-floor to increase, and the capacity price that would prevail absent a TSL-floor for the rest of their capacity.
- Intermittent and storage resources that are assumed to contribute less to transmission security than resource adequacy should also be compensated using a two-part rate. These resources would receive the full capacity price for the portion of their UCAP that counts towards transmission security requirements, and the capacity price that would prevail absent the TSL-floor for their remaining UCAP.

These changes would cause SCRs and large resources to be appropriately compensated based on their contributions to resource adequacy requirements. Payments to these resources would be unaffected when LCRs are not set at the TSL-floor.[149]

2. Demand Curves overvalue surplus capacity beyond the TSL-based requirement

The ICAP Demand Curves are designed to set prices at the Net Cost of New Entry (Net CONE) as capacity in a locality approaches the LCR, and a declining price at larger surplus levels. This structure recognizes that surplus capacity has incremental (but diminishing) value for reducing the risk of load shedding. The New York City demand curve values up to 18 percent more capacity than the surplus requirement.

Surplus capacity has less incremental benefit when requirements are based on transmission security as opposed to resource adequacy. This is because transmission security requirements secure against a deterministic and highly conservative scenario, regardless of its probability of occurring.[150] Hence, the probability of load shedding due to insufficient capacity in a locality is

percent for the 2024/25 capability year and 215 MW of capacity from Ravenswood 3 that causes an increase in the TSL-floor.

148 Note that the addition of SCRs may also cause the NYCA IRM and Optimizer-determined LCRs to increase because SCRs are not available at all times. This affects SCRs' capacity payments through the Capacity Accreditation Factor (CAF).

149 For a more detailed discussion, see our presentation at the September 24, 2024 Installed Capacity Working Group, available here.

150 In particular, transmission security plans for a scenario in which the single largest contingency (or in the case of New York City, the two largest contingencies) has taken place. Other study assumptions include a

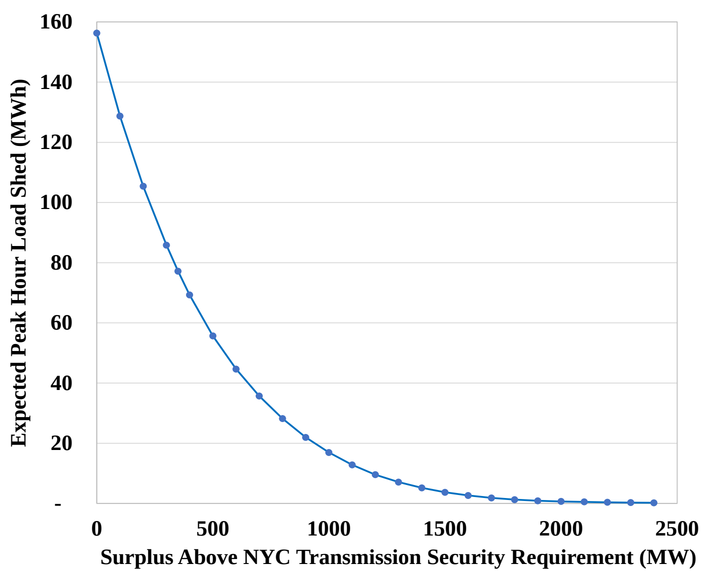
vanishingly low when the locality satisfies transmission security requirements that significantly exceed resource adequacy-based requirements. For example, Figure 27 in Subsection B shows that in the 2025/26 LCR case, which set the NYC LCR at its TSL-floor, additional capacity in New York City provides only slightly more reliability benefit than capacity upstate at the tariff-prescribed level of excess, despite being much more costly.

The current demand curves may significantly overvalue surplus capacity in localities with LCRs set by TSL-floors. For example, a ten percent capacity surplus in New York City may be priced at a large premium over capacity in the Rest of State area, despite providing little or no marginal reliability benefit compared to Rest of State capacity. Hence, we recommend developing sloped demand curves reflecting the marginal value of surplus capacity for use when an LCR is determined by a TSL (Recommendation 2023-4).

A transmission security-based demand curve should consider the incremental benefit of surplus capacity for maintaining transmission security. Transmission security assessments consider a set of deterministic large contingencies, but also include assumptions about other system conditions such as load and generator availability. Many of these assumptions are required to represent "credible combinations of system conditions which stress the system" but do not have specific values defined by NYSRC, NPCC, or NERC reliability criteria.[151] Hence, it is reasonable to consider that surplus capacity has incremental value for transmission security when it would help to preserve reliability under more extreme credible values for these assumptions.

Figure 33 illustrates expected load shed in the peak hour simulated by the transmission security margin calculation for New York City, as a function of surplus capacity. We simulated unserved energy by drawing load and generator outages from random distributions using the Monte Carlo method and limiting imports to the New York City TSL. A surplus of zero indicates that local capacity is equal to the TSL-based requirement. At this level of surplus, there is some expected unserved energy because load and generator outages may exceed the

Figure 33: Expected Load Shed at Transmission Security Requirement



summer peak load level, outages of other generators, unavailability of emergency actions (such as SCRs or external assistance), and conservative levels of intermittent resource output.

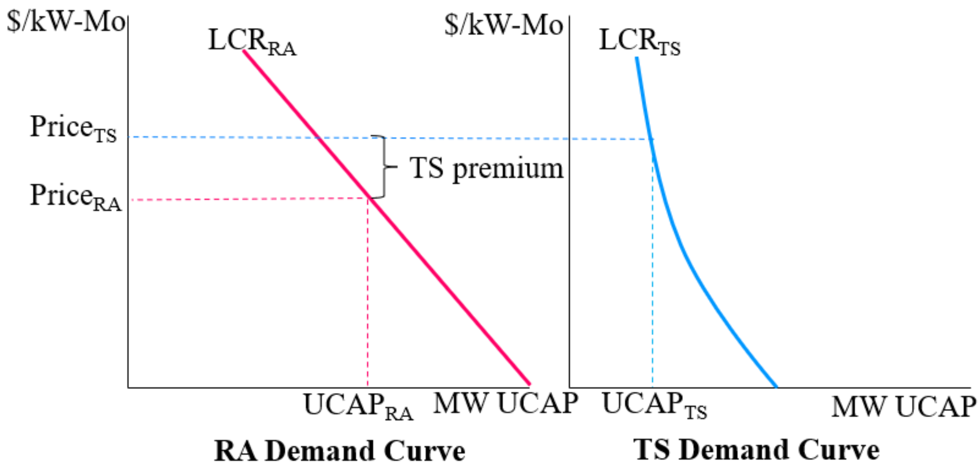
151 See section B.1 of the NYSRC Reliability Rules & Compliance Manual, available here.

values assumed in the TSL floor calculation. At larger surplus levels, EUE falls because reliability is maintained even at more extreme levels of load and generator outages.

Figure 34 illustrates how recommendations 2022-1 and 2023-4 could be implemented to determine capacity market prices and settlements. Our proposal has the following features:

- The Resource Adequacy (RA) Demand Curve on the left has a requirement determined by the LCR Optimizer without enforcing the TSL-floor.
- The Transmission Security (TS) Demand Curve on the right has a requirement equal to the locality's TSL-floor and a slope that reflects the incremental benefit of capacity towards TS requirements.
- Each supplier is assigned separate resource adequacy and transmission security UCAP ratings, reflecting their marginal contributions towards each set of criteria.
- Prices for resource adequacy and transmission security are determined separately at the intersection of UCAP supply and demand on each curve.
- Each supplier is paid its RA UCAP times the RA Price, plus its TS UCAP times the TS Premium (difference between the RA and TS prices) if a higher price would be set for TS than for RA.

Figure 34: Illustration of Transmission Security Demand Curve Concept



We estimated a reduction of aggregate New York City capacity payments by $380 million using preliminary data for the 2025/26 capability year using this proposed approach compared to the status quo. The majority of the savings are from lower prices when using a transmission security demand curve that appropriately values surplus capacity. This proposal would necessitate the consideration of a potential demand curve reference technology's ability to contribute to transmission security requirements in the Demand Curve Reset process. [152]

[152] For a more detailed discussion of this proposal, see our presentation at the September 24, 2024 Installed Capacity Working Group, available here, including appendix content.

F. Financial Capacity Transfer Rights for Transmission Upgrades

Investment in transmission can reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. Transmission often also provides significant resource adequacy benefits. To provide efficient incentives to invest in transmission, we recommend that transmission developers receive financial capacity transfer rights (FCTRs) for upgrades. When a transmission upgrade improves the capacity transfer limit between zones, the FCTR should provide compensation based on the difference in the value of capacity between those zones. The Appendix of this report analyzes how FCTRs might affect a transmission investment decision.[153]

As intermittent generation is added to the grid, there will be additional opportunities for investment in transmission to deliver the output to consumers. However, because of the absence of capacity market compensation for transmission projects, developers lack the critical market incentive necessary for market-based (rather than cost-of-service-based) investment in transmission. Thus, it is unlikely that efficient market-based investments in transmission will occur if transmission developers cannot receive capacity market compensation.

This recommendation will be particularly valuable in combination with our recommendation to implement more granular capacity zones (Recommendation 2022-4 – see Section VIII.C). As the capacity market captures differences in locational value based on more complete transmission constraints, developers may find it economic to make voluntary upgrades to improve their capacity payments. Our proposal for FCTRs would allow developers who pursue elective upgrades to be compensated for their reliability benefits. In addition, we highlight in Subsection VIII.C where an FCTR (which is a "CCP Credit/Charge") could be used to ensure efficient compensation to generators that affect transfer capability across constrained interfaces.

G. Assessment of Seasonal Capacity Market Framework

The capacity market was designed to procure sufficient resources to reliably satisfy demand during summer peak conditions. It has been taken for granted that this design would also make sufficient resources available to satisfy demand at other times of the year. However, the evolving supply mix and demand patterns will require NYISO to reform the capacity market to avoid reliability issues during peak winter conditions. This subsection discusses these issues.

Causes of Changing Seasonal Reliability Risks

Resource adequacy risk in the NYISO system has historically been concentrated in summer because peak load is much higher in summer than winter. Winter resource adequacy risk is now growing relative to summer for the following reasons:

153 See Appendix Section VI.H for additional details.

- *Natural gas limitations* – Approximately 7 GW of generation capacity in eastern NYISO can operate only on natural gas and lacks backup fuel capability.[154] On very cold days, many of these generators cannot acquire gas on a non-firm basis. Most of them do not have firm pipeline gas transportation contracts. In the past decade, gas pipeline infrastructure into the New York/New England region has not kept pace with demand growth by utilities, causing non-firm gas availability for power plants to shrink.
- *Growing winter demand* – Winter demand for electricity is growing, driven by state policies that encourage adoption of electric heating appliances. NYISO's 2025 Gold Book forecasts that the gap between summer and winter peak load will shrink from over 7 GW in the near term to 4 GW by 2035. Winter peak load is projected to exceed summer peak load by 2040.[155]
- *Retirement of fuel secure generation* – Major retirements of non-gas resources in recent years in New York and New England have been replaced by gas-fired generators competing for the limited supply of gas available in the Northeast on cold winter days.
- *Neighboring areas going through similar transition* – Neighboring regions increasingly expect a shift towards winter reliability risk. Hydro-Quebec is a winter-peaking system which has gone from a net exporter to a net importer of capacity during peak winter months. ISO-NE and PJM both anticipate that winter reliability risk will surpass summer risk in the coming years and have proposed capacity market reforms to encourage generators to secure firm gas supply.[156] Such actions may have impacts on the pipeline gas transportation available to NYISO generators, and emergency assistance from neighbors may be less available to the NYISO during tight winter conditions.
- *New resource characteristics* – It is uncertain if the 1,250 MW Champlain Hudson Power Express transmission line from Quebec to New York City will sell capacity in winter.[157]

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154 See MMU Analysis of Gas Availability in Eastern New York, presentation to New York State Reliability Council (NYSRC) Installed Capacity Subcommittee, January 3, 2024, available here.

155 It is important to note that electrification of heating demand does not imply a commensurate increase in gas available to power plants. First, air source heat pumps (which make up the vast majority of heat pump sales in New York) are less efficient in very cold weather. As a result, the reduction in residential gas demand they provide is offset by the fuel needed to meet their electric demand on the coldest days. Second, about a third of homes in New York with fossil fuel heating equipment use heating oil or kerosene, rather than gas, so conversion of these homes to electric heat will increase demand for electricity without freeing up more gas supply. Third, total heating demand is expected to grow in the coming decade in both New York and New England, offsetting the reduction of gas use due to electrification. Finally, gas LDCs may respond to lower customer gas demand by reducing their purchases of expensive 'peaking' resources such as stored and imported LNG, so that available non-firm pipeline gas on very cold days does not increase. As a result, electric demand for heating could grow much faster than gas available to generators.

156 See PJM May 30, 2023 presentation "Update on Reliability Risk Modeling" (available here) PJM June 28, 2023 presentation "PJM Capacity Market Fuel Assurance Accreditation" (available here), and documents related to ISO-NE market project "Resource Capacity Accreditation (RCA) in the Forward Capacity Market", available here.

157 The public contract for Tier 4 RECs between the owners of the CHPE project and NYSERDA appears to assume a reference winter UCAP value of 0 MW in the winter capability period – see Tier 4 Renewable Energy Certificate Purchase and Sale Agreement between the New York State Energy Research and

If entry of this project causes retirement of fuel-secure resources, winter reliability margins could be further reduced.

The capacity market's purpose is to efficiently attract and retain enough capacity to ensure resource adequacy. As winter risk grows, it is critical to set capacity prices and accreditation values that will attract and retain resources that are reliable during the periods of greatest need. The following subsections discuss improvements to the capacity market structure that are needed to quantify and value winter reliability.

Improvements Needed to Capacity Market Design

The capacity market is designed to efficiently attract and retain capacity needed to satisfy the system's resource adequacy requirements. NYISO's market has historically not been designed to consider the unique factors that drive supply and demand for reliable capacity in summer and winter separately. There is a need to reform key elements of the market to ensure that prices and payments remain consistent with resources' reliability contributions as winter risk emerges. In the remainder of this subsection, we discuss the current shortcomings of the seasonal framework and proposed improvements to address these shortcomings.

1. Summary of Current Seasonal Market Design

Under NYISO's current capacity market framework, several key capacity market parameters are determined for all months by an annual study process conducted prior to the corresponding capability year:

- *ICAP Requirements* – A single annual set of ICAP requirements based on the Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) apply to all months of the year. These are determined by resource adequacy model studies conducted in the year prior to the corresponding capability year (the "IRM/LCR study").
- *Capacity Accreditation Factors* – Annual CAFs are determined for each resource class based on the IRM/LCR study. The CAF value is the same for all months of the year and is intended to reflect the resource's contribution to annual load shedding risk. When a resource type's reliability varies seasonally, its CAF implicitly reflects the relative amounts of summer and winter risk in the IRM/LCR study.
- *Seasonal Demand Curves* – Beginning in the 2025/26 capability year, separate summer and winter demand curve reference prices are set so that the reference point is higher in the season that has more reliability risk in the IRM/LCR study. This process is described below.

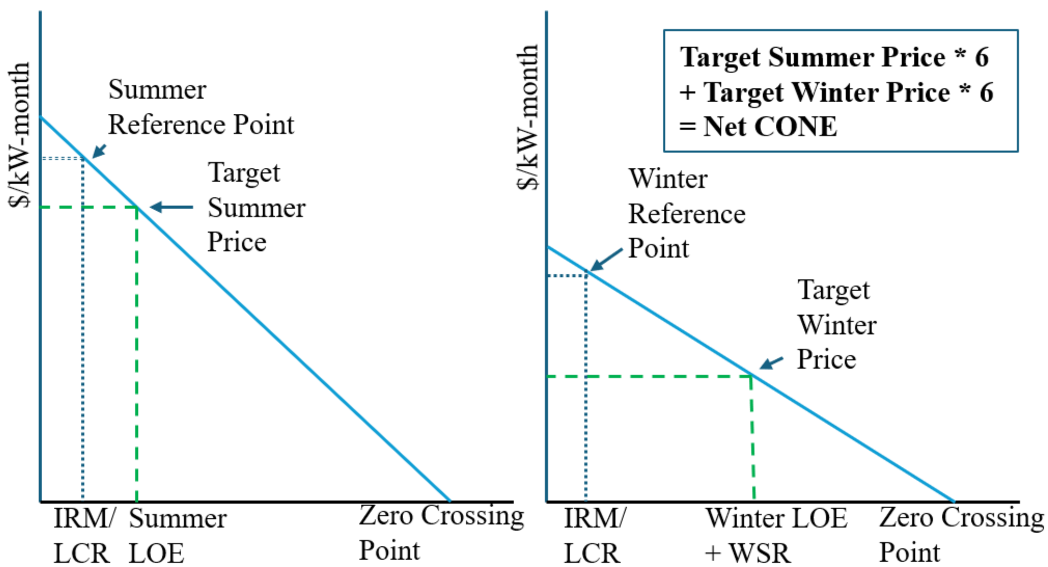
Figure 35 illustrates how summer and winter reference points are determined under the NYISO's new seasonal methodology. Reference points are chosen so that the demand curve reference unit

Development Authority and H.Q. Energy Services (U.S.) Inc, available here on NYSERDA's webpage as of April 4, 2024.

earns its net cost of new entry (Net CONE) when summer capacity is equal to the ICAP requirement plus the tariff-prescribed level of excess (LOE). The reference points are intended to produce seasonal prices that mirror the proportion of reliability risk occurring in winter and summer in the IRM/LCR study (subject to a 35 percent floor in each season). It is assumed that when summer capacity is at the LOE, the winter capacity surplus includes the incremental ICAP of generators that have higher ratings in winter (the "Winter Summer Ratio", or WSR).

NYISO recently developed changes to the accreditation of gas and oil units in eastern New York based on their winter fuel arrangements.[158] Generators will choose between the "firm" and "non-firm" capacity accreditation resource class (CARCs), which will have separate CAFs. Generators can qualify for the firm CARC by committing to maintain firm gas pipeline transportation arrangements or sufficient stored inventory to operate for 56 hours across a seven-day period. Generators must elect a CARC during the IRM/LCR study process in August prior to the capability year, and they cannot move between firm and non-firm CARCs after that date. The difference between the firm and non-firm CAF values will ultimately depend on the level of winter reliability risk in the IRM/LCR study.

Figure 35: NYISO Seasonal Reference Point Proposal
Assuming Higher Summer Risk in IRM/LCR Study



2. Analysis of Current Design Shortcomings

The improvements to seasonal reference points and accreditation based on firm fuel supply discussed above have already improved over the historic capacity market design, in which winter prices bore no relationship to winter reliability risk. However, the capacity market will still rely

158 See NYISO April 30, 2025 Management Committee presentation "Modeling Improvements for Capacity Accreditation: Firm Fuel", available here.

on an annual approach to setting key market parameters that lacks the flexibility to respond to seasonal variations in available capacity. The following shortcomings will limit the market's ability to effectively coordinate seasonal capacity supply decisions (such as imports and firm fuel elections) in the coming years:

Seasonal prices driven by ex-ante study assumptions – under the current framework, the ratio of summer to winter risk in the annual IRM/LCR study has a major impact on the CAFs and seasonal demand curve reference points. However, some factors that affect seasonal reliability risk (such as seasonal import levels and firm fuel elections) are either not known at the time of the IRM study or not incorporated in it. For example, the IRM study has historically assumed a consistent level of capacity imports across the year, but recent years have seen major reductions of net imports in winter compared to summer in the actual market. As a result, CAFs and seasonal prices could fail to align with actual system needs, leading to inefficient incentives for seasonal supply decisions such as imports, exports, firm fuel and demand response.

Poor coordination of firm fuel elections – Generators are currently required to elect firm fuel 16 months before the relevant winter period and cannot subsequently change firm elections. This is poorly aligned with fuel procurement timelines and significantly limits incentives for generators to respond to system needs by acquiring more firm fuel. Moreover, fuel elections pose a dilemma for the IRM and market process that will require market changes to resolve.

Generators will consider the requirements, prices and non-firm CAFs when deciding how much firm fuel to elect each year. But the amount of fuel assumed to be available to generators in the IRM study could have a large impact on these values. If fuel availability in the IRM study is modeled based on generators' elections, generators will have to decide what to elect before knowing the expected difference between firm and non-firm revenues (which would depend on the elections of all generators). This could lead to volatile market outcomes as elections cannot subsequently be changed even if it would be economic to do so. Alternatively, if fuel availability in the IRM study is not modeled based on generators' elections, market outcomes including CAFs, requirements and prices will be unaffected by firm elections and may not be determined consistently with generators' actual supply commitments.[159] This lack of feedback between firm elections and the market could incentivize generators to under-elect or over-elect firm fuel (resulting in adverse reliability or consumer cost impacts, respectively).

For the 2026/27 IRM study, NYISO has proposed to model fuel availability not based on generators' elections, and may modify this approach in future years.[160] For the reasons discussed

159 For more detailed discussion, see March 17, 2025 ICAPWG presentation "Coordination of Firm Elections in the Capacity Market", here.

160 See April 11, 2025 NYSRC EC presentation "Fuel Availability Constraints Modeling Phase 2", here.

in the preceding paragraph, changes to the capacity market process will be needed to effectively coordinate firm fuel elections regardless of the IRM modeling method.

<u>*Volatile outcomes caused by winter-summer ratio*</u> – The current seasonal market framework requires NYISO to make assumptions about the difference in the amounts of ICAP sold in summer and winter. This assumption (the Winter Summer Ratio, or "WSR") has a large impact on the value of the demand curve reference point prices. If the WSR is biased or inaccurate, the reference points will not be set at levels that produce revenues equal to the Net CONE when summer surplus is equal to the tariff-prescribed level of excess (LOE).

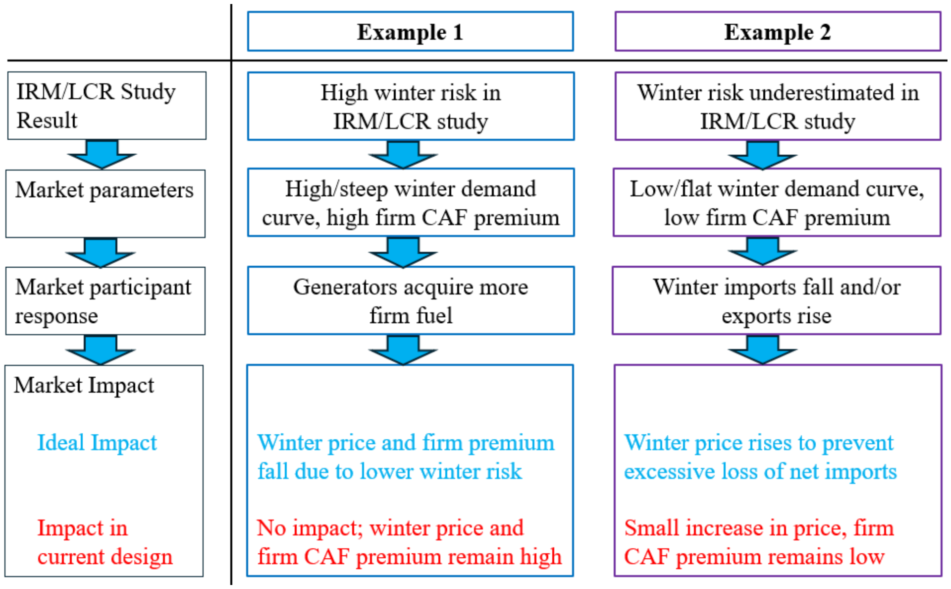
In the past, the WSR was primarily driven by stable differences in generators' seasonal capability. In the coming years, UDR resources (particularly the planned Champlain Hudson Power Express (CHPE) project) could cause changes in seasonal capacity sales in the localities. There is a risk that seasonal variation in sales by UDRs will result in an inaccurate WSR and extreme pricing outcomes under current rules, including (1) the WSR calculation doesn't account for seasonally varying sales of UDR resources, and (2) the WSR calculation is backward-looking and doesn't promptly reflect major changes to the resource mix. For example, we estimate that if CHPE sells no capacity in December through February, the New York City winter reference point for 2026/27 would be set approximately $7.60 per kw-month above the appropriate level with an impact on the New York City winter capacity price of approximately $1.31.[161]

Figure 36 illustrates how the inflexibility of the current framework could lead to poor market outcomes and incentives in winter. In the two examples shown, rational behavior by market participants does not cause market parameters to respond appropriately:

- *Example 1*: If winter risk in the IRM/LCR study is high, the resulting high winter prices and firm premium should motivate more generators to acquire firm gas or increase oil inventories. But under the current design, generators would lack incentives to acquire firm fuel (because they cannot move from the non-firm to firm CAF) and any acquisition of firm fuel would have no impact on winter prices and CAFs.
- *Example 2*: If winter risk in the IRM/LCR study is low, the resulting low and flat winter demand curves may lead to loss of capacity imports or even net exports from NYISO in winter. Because the low/flat winter demand curve would remain fixed, suppliers may have incentives to reduce winter imports and increase exports even when this would cause elevated reliability risk in NYISO.

161 This price impact considers expected surplus levels in 2026/27. We arrive at this estimate by recalculating the winter-summer ratio assuming CHPE is included as selling 1,250 MW in all summer months as well as November, March and April, then recalculating the demand curve reference points using 2025/26 parameters. See Section VI.I in the Appendix for more details of problems caused by the WSR methodology.

Figure 36: Potential Market Outcomes Under Current Seasonal Framework



3. Seasonal Capacity Market Proposal

The current seasonal market framework is incomplete because prices and CAFs are largely determined by the summer/winter risk shares in the annual IRM/LCR study and lack flexibility to respond to seasonal variations in supply. In a well-functioning market, prices and generator payments would adjust to changes in supply, providing efficient incentives to attract resources needed to maintain reliability in each season.

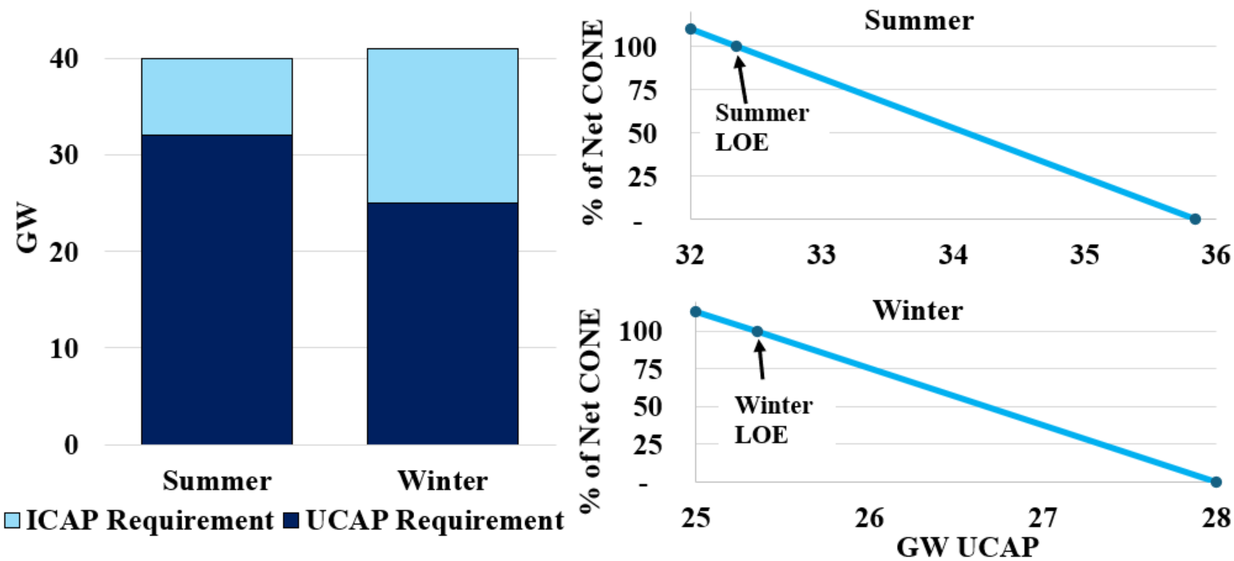
Hence, we recommend establishing seasonal capacity requirements, CAFs, and demand curves (Recommendation 2022-2). This would consist of the following:

- *Seasonal Requirements*: establish seasonal ICAP requirements that reflect the amount of capacity needed to satisfy the reliability criterion in each season. This could be done using the IRM/LCR modeling approach to determine separate requirements for satisfying summer and winter reliability targets.
- *Seasonal CAFs*: calculate separate summer and winter CAFs for each resource class. As a result, assumptions about relative summer and winter risk in the IRM/LCR study would not distort the value of the CAFs when there are changes in the supply mix.
- *Firm Elections Closer to Capability Period*: move the deadline for elections of firm fuel closer to the corresponding winter capability period (e.g., in the fall before the corresponding winter). This would better align firm fuel decisions with the timing of fuel contracting opportunities for suppliers, and create opportunities to suppliers to secure hedges through bilateral trades or the capacity strip auction to justify the additional costs of acquiring firm fuel.
- *Seasonal Demand Curves*: establish separate summer and winter capacity market demand curves, using UCAP requirements derived from the seasonal ICAP requirements. The UCAP requirement would represent the amount of seasonally available capacity needed to comply with reliability criteria in the IRM/LCR study. Changes in the amount of

seasonal UCAP sold in the auction (for example, due to changes in the amount of firm fuel held by generators or net imports) would result in movement along the demand curve, treating seasonal UCAP from any source interchangeably.[162] Reference prices of each season's demand curve would be set so that the price approaches the Net CONE of the reference technology when UCAP supply approaches the UCAP requirement in any season. It will be necessary to review the current demand curve shape and slopes to ensure that prices reflect the reliability value of capacity when risk is distributed across seasons.[163]

Figure 37 illustrates how seasonal capacity requirements (determined based on the amount of capacity that satisfies the reliability criterion in each season) would translate into seasonal demand curves based on the UCAP-equivalent of the requirements. Prices would result in the reference technology earning its Net CONE when reliability risk approaches the planning criterion (e.g. "1 day in 10 years" LOLE) in any one season or in aggregate across both seasons.

Figure 37: Illustration of Requirements and Demand Curves Under Seasonal Proposal



The proposed approach has the following advantages:

162 The translation to a seasonal UCAP requirement should be done using the seasonal ICAP to UCAP ratio of the resource mix modeled in the IRM/LCR study (with adjustment for differences in generator EFORd values between the capacity market and IRM study). As a result, the importance of accurate assumptions regarding the quantity seasonally variable capacity (such as imports or firm gas) would be greatly reduced. For example, if the IRM/LCR study assumes no generators hold firm gas and a resource owner subsequently acquires firm gas, the UCAP requirement would remain fixed based on the ICAP-to-UCAP ratio of resources in the IRM/LCR study and the generator that acquired firm gas would sell additional UAP, causing the market to clear further along the demand curve.

163 For example, combined summer and winter capacity revenues should equal the reference unit's Net CONE when the risk level with the current capacity surplus is one half of the reliability criterion in both seasons.

- It does not rely on accurate assumptions regarding relative summer and winter risk in the IRM/LCR study;
- It does not rely on ICAP Winter-Summer Ratio to set demand curves;
- Requirements and prices in summer and winter reflect the need for capacity that is reliably available (UCAP) in each season, rather than a requirement for nameplate capacity regardless of availability (ICAP) across all seasons;
- Seasonal CAFs convert all resources' capacity to terms of equivalent marginal value, so that demand curves respond appropriately to changes in supply from any source; and
- Greater stability of seasonal prices and CAFs because they are not determined by sensitive estimates of relative winter and summer risk.

In the near term, we recommend that NYISO update its market processes to mitigate the risk of extreme pricing outcomes caused by inaccuracies in the winter-summer ratio (Recommendation 2023-5). Potential solutions for the treatment of UDRs could include a requirement for UDR owners to make separate seasonal elections for summer and winter in the IRM study process, and/or changes to the calculation of the WSR parameter to account for unsold capacity. In addition, the WSR calculation should account for changes to the resource mix (such as known entry or retirements) rather than rely on a backward-looking calculation. Finally, corresponding modifications to the seasonal reference point formula may be required to ensure appropriate prices if the WSR value is less than one. We recommend making these improvements on an expedited basis to address the near-term risk of WSR distortions caused by UDRs. In the long term, our recommendation to adopt a seasonal capacity market discussed earlier in this section would eliminate the need for the WSR parameter entirely.

4. Conclusion of Winter Capacity Market Assessment

In this subsection, we highlighted improvements that are needed to the modeling of winter reliability risk in NYISO's resource adequacy model and capacity market design elements that will result in volatile and inefficient prices as winter risk grows relative to summer risk. We make the following recommendations:

- Establish seasonal capacity requirements, CAFs, and demand curves (Recommendation 2022-2); and
- Update market processes to mitigate the risk of extreme pricing outcomes caused by inaccuracies in the WSR (Recommendation 2023-5). This should be addressed on an accelerated schedule due to the near-term nature of the risk.

IX. External Transactions

Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas. The latter is beneficial because it allows:

- Low-cost resources in one area to compete to serve consumers in another area who might otherwise rely on higher-cost resources; and
- NYISO to access emergency power, reserves, and capacity from neighboring systems, helping to lower the costs of meeting reliability standards across control areas.

NYISO imports and exports substantial amounts of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. In addition, Long Island and New York City are directly connected to PJM and New England via six controllable lines, which together can import up to roughly 2.7 GW directly to downstate areas.[164] Hence, NYISO's total import capability is large relative to its load, making efficient interface scheduling essential.

This section provides a summary of physical interchange patterns between New York and neighboring control areas in recent years in subsection A and a summary of virtual import and export scheduling in subsection B. Subsection C evaluates three aspects of the performance of Coordinated Transaction Scheduling with ISO New England and PJM: overall production cost savings from CTS, the impact of transaction fees imposed on CTS transactions, and drivers of forecast error in the models used to schedule CTS transactions.

A. Interchange between New York and Adjacent Areas

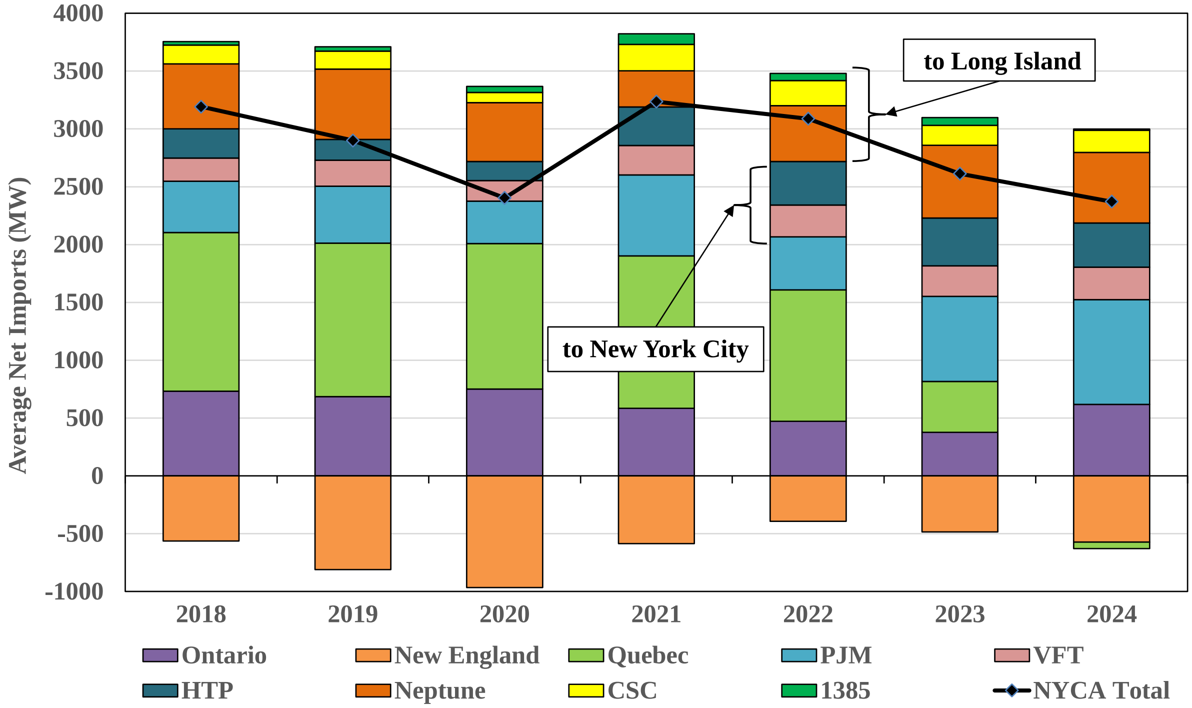
Figure 38 summarizes the net scheduled imports from neighboring control areas from 2018 through 2024 during peak hours (i.e., 6 am to 10 pm, Monday through Friday).[165]

In 2024, average total net imports from neighboring areas during peak hours were approximately 2,370 MW in peak hours, marking a 9 percent decrease from the previous year and the lowest level since 2018. Nonetheless, imports continued to serve a significant portion of NYISO load, accounting for more than 12 percent of peak-hour demand in 2024.

164 The controllable lines are: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, the Neptune Cable, and the A line. The A line is a PAR-controlled line that interconnects NYC to New Jersey, which is scheduled as part of the primary PJM to NYISO interface and is operated under the M2M JOA with PJM in real-time. This line is further evaluated in Appendix Section V.F.

165 Figure A-54 to Figure A-57 in the Appendix provide additional details.

Figure 38: Average Net Imports from Neighboring Areas
Peak Hours, 2018-2024



Controllable Interfaces to New York City and Long Island

On Long Island, net imports from neighboring control areas averaged over 800 MW during peak hours in 2024, serving more than 33 percent of peak-hour demand. The Neptune Line was typically scheduled at its full available transfer capability, regardless of system conditions, while flows across the Cross Sound Cable and the 1385 Line were more responsive to variations in gas price spreads between Long Island and New England.

In New York City, net imports over the HTP and Linden VFT lines averaged 665 MW during peak hours in 2024, satisfying nearly 11 percent of the City's peak-hour demand. This marked the third consecutive year in which average imports across the two scheduled lines exceeded 650 MW, driven primarily by increased flows over the HTP line. Persistent discounts in natural gas prices in northern New Jersey relative to other northeastern pipeline hubs continued to incentivize greater volumes of low-cost imports from PJM to New York City.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces fell by 16 percent from 2023 to 895 MW in 2024 in peak hours, the lowest level observed since 2018. This decrease was largely due to reduced imports from Quebec. Increased net exports to New England, which also experienced reduced imports from Canada, further contributed to the overall decline. However, higher imports from PJM and Ontario partially offset these reductions.

Among the primary interfaces, the Quebec interface historically accounted for the largest share of net imports. However, for the first time, New York became a net exporter to Quebec in 2024. The decline in net imports from Quebec began in March 2023, driven by extensive wildfires across several Canadian provinces, significantly affecting generation and transmission capabilities in Quebec. Persistent drought conditions throughout 2024 further exacerbated this issue, leading to even lower import levels.

Net imports across the primary interfaces with PJM and New England followed changes in gas price spreads and emission allowance price differences between these regions. For example, during winter months, New York normally imported from PJM and exported to New England, consistent with seasonal gas price spreads (i.e., New England > New York > PJM). These variations in net imports reflect the complex interactions between electricity and natural gas markets, as natural gas is a crucial fuel for power generation, particularly in the Northeast region. In addition, imports from PJM have increased over the past two years as RGGI allowance prices have risen 54 percent from 2022 to 2024, adding around $3.25/MWh of input costs to a typical combined cycle generator in NYISO relative to most areas of PJM.[166]

B. Virtual Imports and Exports in the DAM

Traders frequently schedule transactions between NYISO markets and neighboring control areas in the day-ahead market but subsequently withdraw these transactions in the real-time market. We refer to these external transactions as “virtual” imports and exports, as they function similar to ordinary virtual supply and load scheduled in the load zones.

Figure 39 examines the frequency and magnitude of scheduled net virtual imports in the day-ahead market in each month over the past two years.[167] The figure indicates that virtual external transactions between NYISO and neighboring control areas occurred in nearly every hour, averaging over 540 MW in the net import direction in 2024 and exceeding 800 MW in approximately 10 percent of hours.

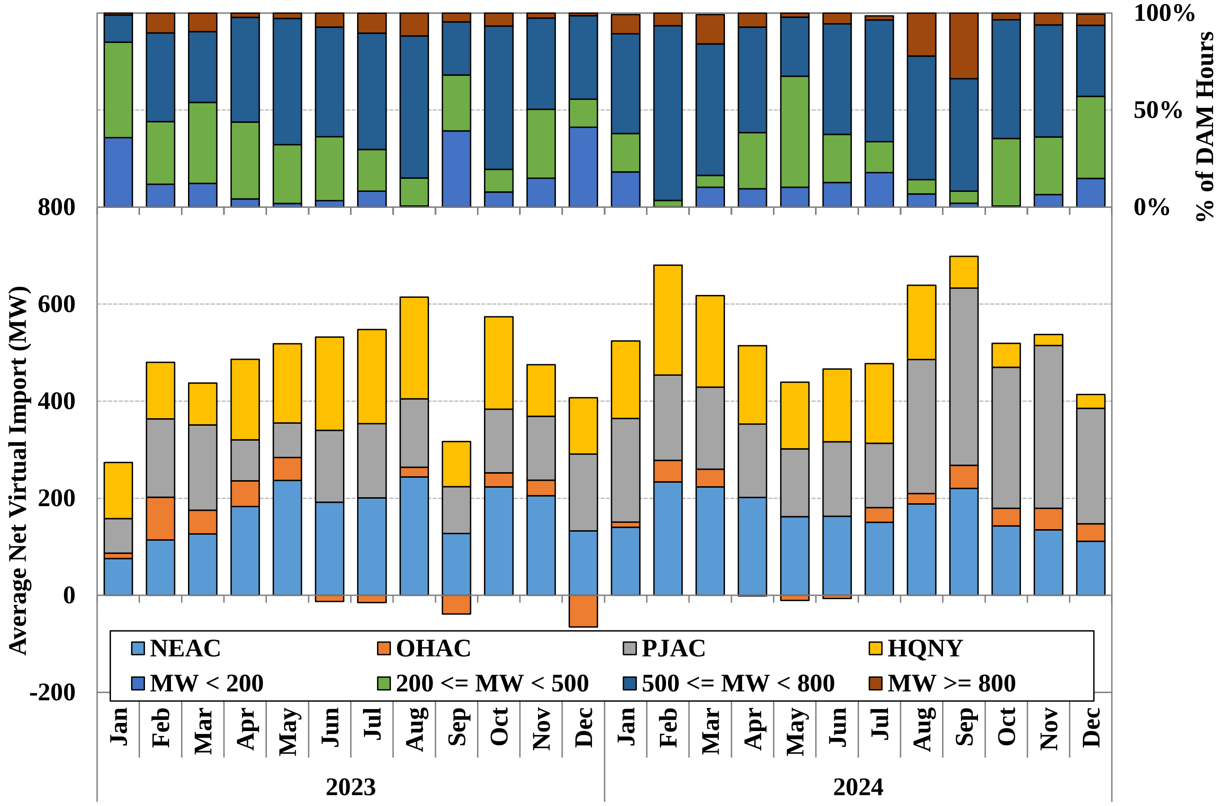
The large and consistent volumes of virtual transactions in the net import direction raise two concerns related to market performance. First, virtual imports and exports are currently treated as physical energy in the day-ahead market but subsequently fail post-DAM checkout with neighboring control areas. This can result in insufficient scheduling during the Forecast Pass of the day-ahead market, necessitating SRE commitments to address capacity deficiencies after the day-ahead market. In fact, net virtual imports were identified as one of the primary drivers of SRE commitments in 2023 and 2024, accounting for approximately 400 MW of missing supply

166 See Figure A-7 in the Appendix for more description of this analysis.

167 See Figure A-38 in the Appendix for more description of this analysis.

on affected days.[168] Furthermore, under the current Dynamic Reserves project proposal, virtual and non-firm imports will count toward satisfying operating reserve requirements, potentially leading to under-scheduling of physical energy and operating reserves.

Figure 39: Virtual Imports and Exports in the Day-Ahead Market
By Month, 2023-2024



Second, despite failing post-DAM checkout, virtual transactions are treated as available in RTC's advisory scheduling time frame but unavailable in RTC's binding scheduling time frame. This inconsistency can create unrealistic ramp constraints in RTC's advisory scheduling time frame, which subsequently distorts real-time prices and schedules in the binding time frame. Instances of this issue have occurred from time to time at the Ontario interface. This inconsistency will likely continue to undermine scheduling efficiency if left unaddressed.

Therefore, NYISO should consider methods to clearly identify imports that are virtual or non-firm in the day-ahead market and avoid treating as equivalent to firm physical supply.

C. Coordinated Transaction Scheduling with ISO-NE and PJM

Coordinated Transaction Scheduling (CTS) allows two neighboring RTOs to exchange real-time market information to clear market participants' intra-hour external transactions more efficiently.

168 See Figure A-94 for additional details on this analysis.

CTS offers two key advantages over the traditional hourly LBMP-based scheduling system used at the interfaces with Ontario, Quebec, and between Long Island and Connecticut:

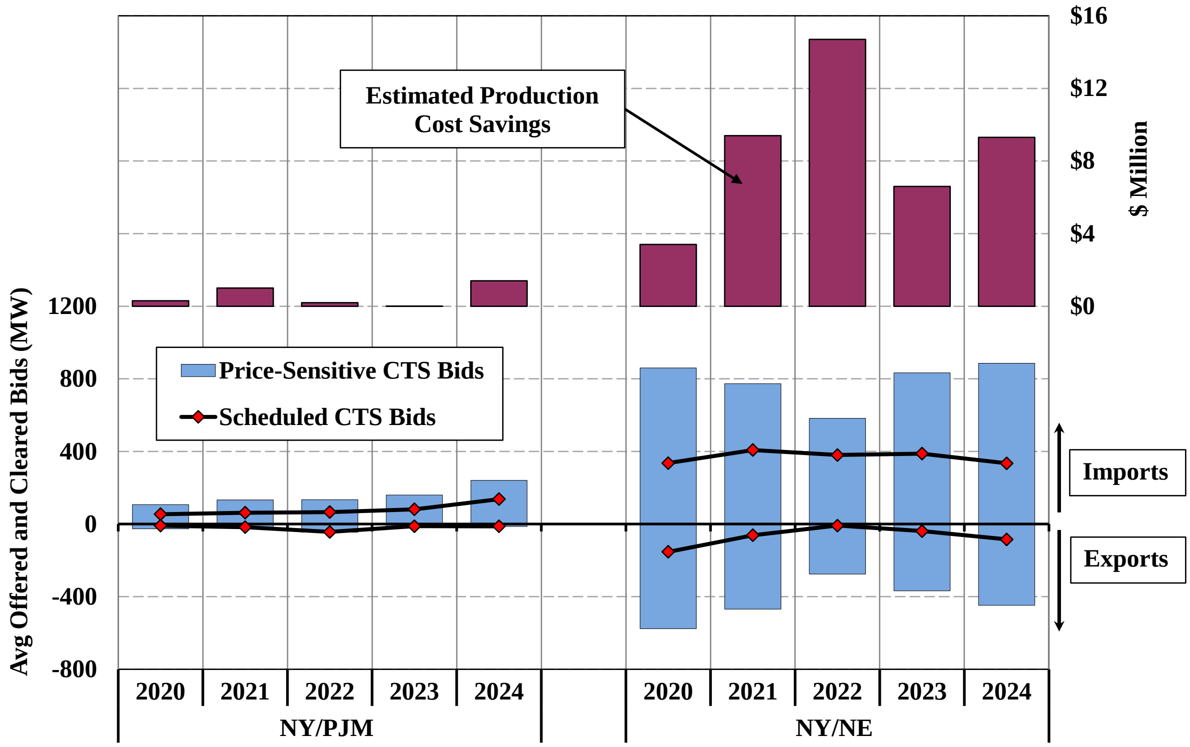
- **Flexibility:** Interface flows can be adjusted every 15 minutes instead of every 60 minutes, allowing for a more efficient response to changing real-time conditions.
- **Timeliness:** CTS schedules transactions much closer to the operating time. Hourly LBMP-based schedules are established up to 105 minutes in advance, while CTS schedules transactions less than 30 minutes ahead, benefiting from more accurate system information.

This subsection discusses several factors affecting CTS performance at the PJM and ISO New England interfaces, particularly the effects of transaction fees and short-term price forecasting errors. We also provide a detailed analysis of key factors contributing to inaccuracies in short-term price forecasts.

1. CTS Bids and Production Cost Savings

Under CTS, traders submit bids that are scheduled when the RTOs' forecasted price spread exceed the bid price. Therefore, it is critical for traders to submit a sufficient volume of price-sensitive bids. Figure 40 evaluates the price-sensitivity of bids at the primary PJM and ISO-NE interfaces and the associated market efficiency gains.

Figure 40: CTS Bids and Production Cost Savings
PJM and NE Primary Interfaces – 2020 - 2024



The lower panel shows the average amount of price-sensitive bids and cleared schedules at each interface during peak hours (i.e., HB 7 to 22) from 2020 to 2024.[169] Only CTS bids are allowed at the ISO-NE interface, while CTS bids and LBMP-based bids are used at the PJM interface. The figure shows LBMP-based bids relative to the short-term forecast so the price-sensitivity of LBMP-based bids can be directly compared to that of CTS bids.[170] The upper panel shows the market efficiency gains from CTS, measured by production cost savings.[171]

The average amount of price-sensitive bids at the PJM interface was significantly lower than at the New England interface in each year from 2020 to 2024. On average, approximately 1,215 MW of bids (including both imports and exports) were offered n a price range of -$10 to $10 per MWh at the New England interface over this five-year period, substantially higher than the 180 MW offered in the same price range at the PJM interface. Likewise, the average amount of cleared price-sensitive bids at the New England interface was more than three-times the average amount cleared at the PJM interface during this period.

Over the five years from 2020 to 2024, interchange adjustments from the CTS process (relative to forecasted hourly schedules) occurred in approximately 85 percent of intervals at the New England interface, compared to just 50 percent at the PJM interface. As a result, the estimated production cost savings from the NY/NE CTS process totaled $43 million over the past five years, compared to just $3 million at the primary PJM interface.[172] We find that production cost savings were significantly higher at the New England interface because of: (a) higher availability of price sensitive offers which allow more frequent intra-hour interchange adjustments, and (b) price forecast accuracy was better at the New England interface. Both factors are examined in greater detail in this subsection.

2. Impact of Fees Charged to CTS Transactions

The differences in performance between the two CTS processes are largely attributable to the large fees imposed at the PJM interface in contrast to the lack of substantial transmission charges or uplift charges on transactions between New York and New England. At the PJM border,

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169 CTS bids in the price range of -$10 to $10 per MWh are considered price-sensitive for this chart.

170 For example, if the short-term price forecast in PJM is $27, a $5 CTS bid to import would be scheduled if the NYISO price forecast is greater than $32. Likewise, a $32 LBMP-based import offer would be scheduled under the same conditions. Thus, the LBMP-based offer would be shown in the figure as comparable to a $5 CTS import bid. Section IV.C in the Appendix describes this figure in greater detail.

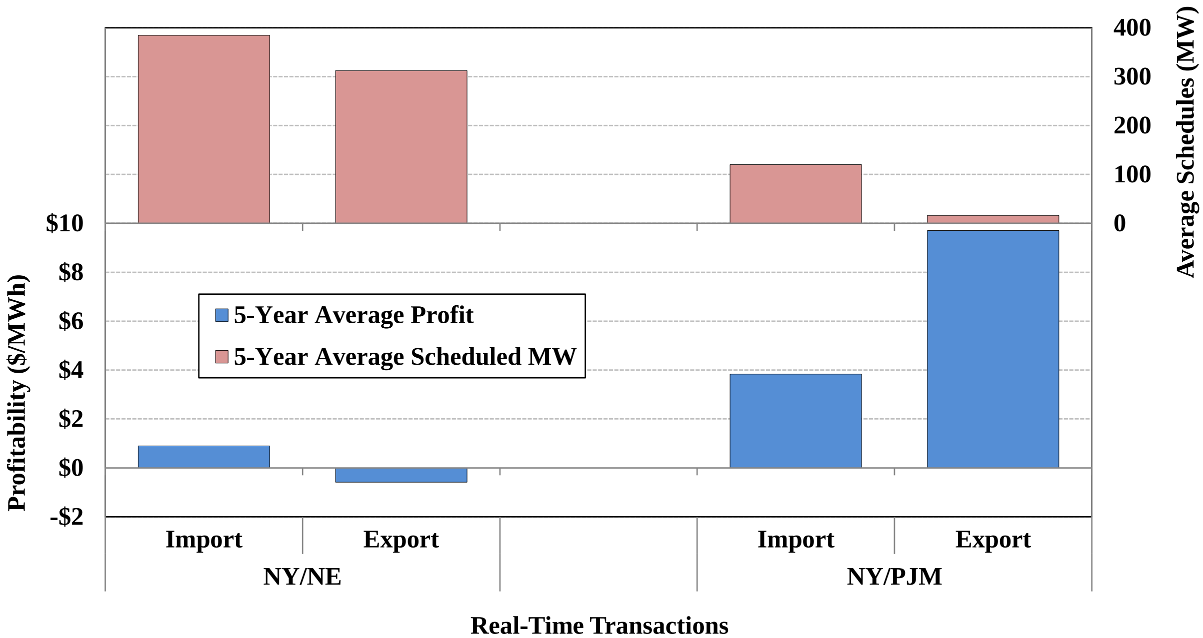
171 Section IV.C in the Appendix describes this analysis in detail.

172 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process, which we proxy based on the advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour. Our evaluation tends to under-estimate the production cost savings, because the hourly schedules that we estimate would have occurred without CTS reflect some of the efficiencies that result from CTS.

NYISO typically charges physical exports a transmission rate ranging from $5 to $8 per MWh (which is the same rate charged to firm network customers) even though these exports are economically curtailable in real time. Consequently, very few CTS export bids are submitted at price-sensitively. In addition, PJM charges a transmission rate averaging less than $1 per MWh on both physical imports and exports that use non-firm service.[173] These charges are a significant economic barrier to realizing the full potential benefits of the CTS process at the PJM border.

Figure 41 examines the average gross profitability of scheduled real-time transactions (excluding the transaction fees discussed earlier) and the average scheduled quantity at the two CTS interfaces from 2020 to 2024.[174] At the primary New England interface, the gross profitability of scheduled real-time transactions (including both imports and exports) averaged roughly $0.25 per MWh over the five-year period. This indicates that CTS has been successful in stimulating competition at the New England interface, since firms have evidently competed away large systematic price differentials.

Figure 41: Gross Profitability and Quantity of Scheduled Real-Time External Transactions
PJM and NE Primary Interfaces, 2020-2024



173 Although PJM increased its Transmission Service Charge substantially to firm imports/exports to $6.34/MWh in 2020, it kept the charge to non-firm transactions (including CTS transactions) at a low level of $0.67/MWh. Also, PJM charges "real-time deviations" (which include imports and exports with a real-time schedule that is higher or lower than the day-ahead schedule) at a rate that averages less than $1/MWh.

174 Real-time external transactions here refer to external transactions that are only scheduled in the real-time market (excluding transactions scheduled in the day-ahead market and flow in real-time).

At the PJM border, scheduled imports exhibited significantly higher average gross profitability, while scheduled exports showed even greater profitability. This reflects that market participants only schedule transactions when they expect the price spread between markets to be large enough to offset the transaction fees they must pay. Consequently, they schedule much lower quantities, particularly for exports from NYISO to PJM, which are subject to the highest transaction fees. These results demonstrate that imposing large transaction fees on low-margin trading strongly discourages transaction scheduling, dramatically reducing trading volumes, liquidity, and sometimes even revenues collected from the fees.

We recommend eliminating or reducing these charges at the interfaces with PJM for several reasons.[175] First, as New York's resource mix evolves to include more intermittent renewable resources, it will become increasingly important to schedule exports to neighboring regions during times when excess renewable generation cannot be absorbed by in-state consumers. A better-performing CTS would facilitate more efficient scheduling between markets, supporting the successful integration of renewable resources. High fees, on the other hand, will lead to more frequent curtailments of renewable generation that otherwise could be exported.

Second, it is unreasonable to apply the same transmission service charges to price-sensitive exports as those assigned to network load customers. These charges are designed to recover the embedded cost of the transmission system, which is planned for the projected growth of network load. However, price-sensitive exports likely contribute nothing to the cost of the transmission system.

Third, we estimate that NYISO collected roughly $1.1 million in export fees from real-time exports to PJM in 2024, while PJM collected $3.5 million in export fees from real-time exports to NYISO. This suggests that lowering the export fee could actually lead to a higher overall collection of fees, because it would allow CTS transactions to be profitable under a wider range of conditions, encouraging greater participation and increasing total trading activity.

3. Evaluation of RTC Forecasting Error

At the two CTS interfaces, the price forecasts produced by PJM were notably less accurate than those produced by NYISO and ISO New England in recent years. Because efficient CTS performance relies heavily on accurate price forecasting, it is essential to evaluate market outcomes to identify the sources of forecast errors. This subsection summarizes our analysis of the factors contributing to NYISO's forecast errors.

RTC schedules resources with commitment lead times ranging from 15 to 45 minutes, including external transactions and fast-start units. Inconsistencies between RTC and RTD prices may

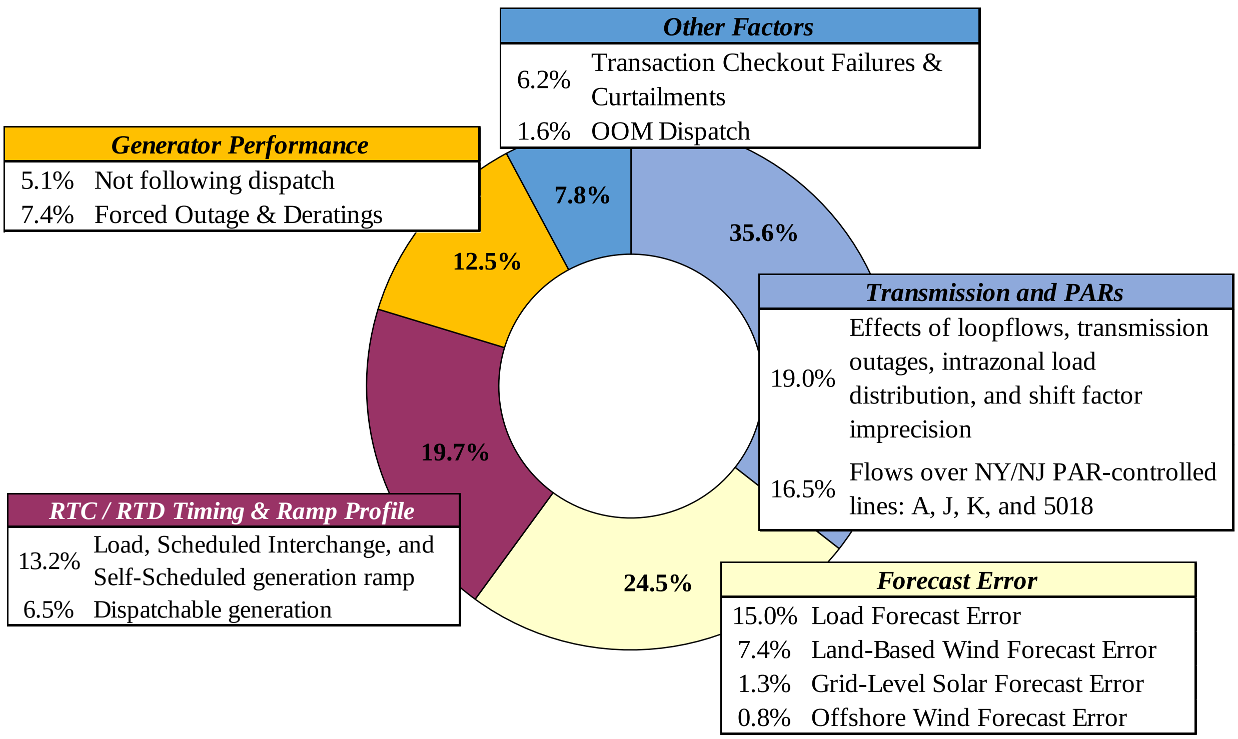
[175] See Recommendation 2015-9.

indicate that some RTC scheduling decisions and/or real-time prices are inefficient. We performed a systematic evaluation of the factors contributing to RTC/RTD price inconsistencies in 2024. This evaluation quantifies the impact of individual factors in each pricing interval, enabling a comparison of their relative significance over time. We expect this evaluation to be valuable as NYISO and stakeholders prioritize different projects to improve market performance.

Figure 42 summarizes the RTC/RTD divergence metric results for "detrimental" factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2024. Our findings show that the primary contributors to RTC price forecast errors in 2024 were largely consistent with prior years.[176]

Figure 42: Detrimental Factors Causing Divergence Between RTC and RTD

2024



The most significant category was transmission network modeling issues, which accounted for 36 percent of RTC/RTD divergences in 2024. Key drivers within this category include:

- Variations in transfer capability available to NYISO-scheduled resources, primarily due to: (a) transmission outages; (b) changes in loop flows around Lake Erie and from New England; (c) inaccuracies in shift factor calculations for NYISO units, which result from the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch; and (d) variations in intra-zone load distribution.

176 See Section IV.D in the Appendix for a detailed description of this metric and analysis of "detrimental" and "beneficial" factors.

- Errors in the forecasted flows over PAR-controlled lines between the NYISO and PJM, specifically the 5018, A, and JK lines, which occur primarily because the RTC forecast: (a) lacks a module to predict loop flow variations from PJM across these lines, (b) assumes no PAR tap adjustments are made to control flows, and (c) incorrectly assumes that NYISO generation re-dispatch does not affect the flows across these lines.

The second-largest category was forecast errors in load (net of behind-the-meter solar) and production from grid-scale wind and solar resources, which accounted for 25 percent of the overall RTC/RTD divergence in 2024.[177] Although the contribution from load forecast errors fell modestly over the past two years from the level recorded in 2022, it remained relatively high. Specifically, between hours 10 and 18, the average RTC forecasted load was approximately 95 MW higher than average RTD load, contributing to a $1.4 per MWh difference between average RTC LBMPs and RTD LBMPs during this period.[178] Operator adjustments to the RTC load forecast were a significant driver of the load difference between RTC and RTD. The impact of forecasting errors related to intermittent wind and solar generation has been on the rise as renewable penetration has expanded in New York. Further, the accuracy of the load forecast is also affected by behind-the-meter solar production forecasting. The significance of this category is likely to increase as more intermittent generation enters the market in the coming years.

The third-largest category, which accounted for 20 percent of RTC/RTD divergence in 2024, was inconsistent assumptions related to the timing of the RTC and RTD evaluations. This includes inconsistent ramp profiles assumed for external interchange, load, self-scheduled generators, and dispatchable generators. For example, RTC assumes external transactions ramp to their schedule by the quarter-hour (i.e., at :00, :15, :30, and :45), while RTD assumes that external transactions start to ramp five minutes before the interval and reach their schedule five minutes after the interval, which is effectively five minutes later than the RTC assumption.[179]

Addressing the sources of inconsistency between RTC and RTD is important for improving the performance of CTS with ISO New England and PJM under present market conditions. Furthermore, New York's resource mix is transitioning away from traditional fossil-fuel generation towards: (a) intermittent renewable generation, which increases uncertainty of resource availability in real time, and (b) new types of peaking generators and energy storage resources, which must be deployed based on short-term forecasts of system conditions. A better-performing RTC will more efficiently schedule flexible resources in response to rapid changes in system conditions, which is critical for successful integration of renewable generation and for maintaining reliability in an evolving grid.

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177 In this case, the forecast error is the difference between the forecast used by RTC and the forecast used by RTD, however, even the RTD forecast can differ from the actual real-time value.

178 See Figure A-70 in the Appendix for more details.

179 Appendix Section IV.E shows the ramp profiles assumed by RTC and RTD for external transactions.

X. Competitive Performance of the Market

We regularly evaluate the competitive performance of the markets for energy, capacity, and other products. This section discusses our evaluation of 2024 market outcomes in three areas:

- Subsection A evaluates our screens for potential economic and physical withholding;
- Subsection B analyzes the application of market power mitigation measures in New York City and in other local areas when generation is committed for reliability; and
- Subsection C evaluates the use of the market power mitigation measures in the capacity market for New York City and the G-J Locality.

A. Potential Withholding in the Energy and Ancillary Services Market

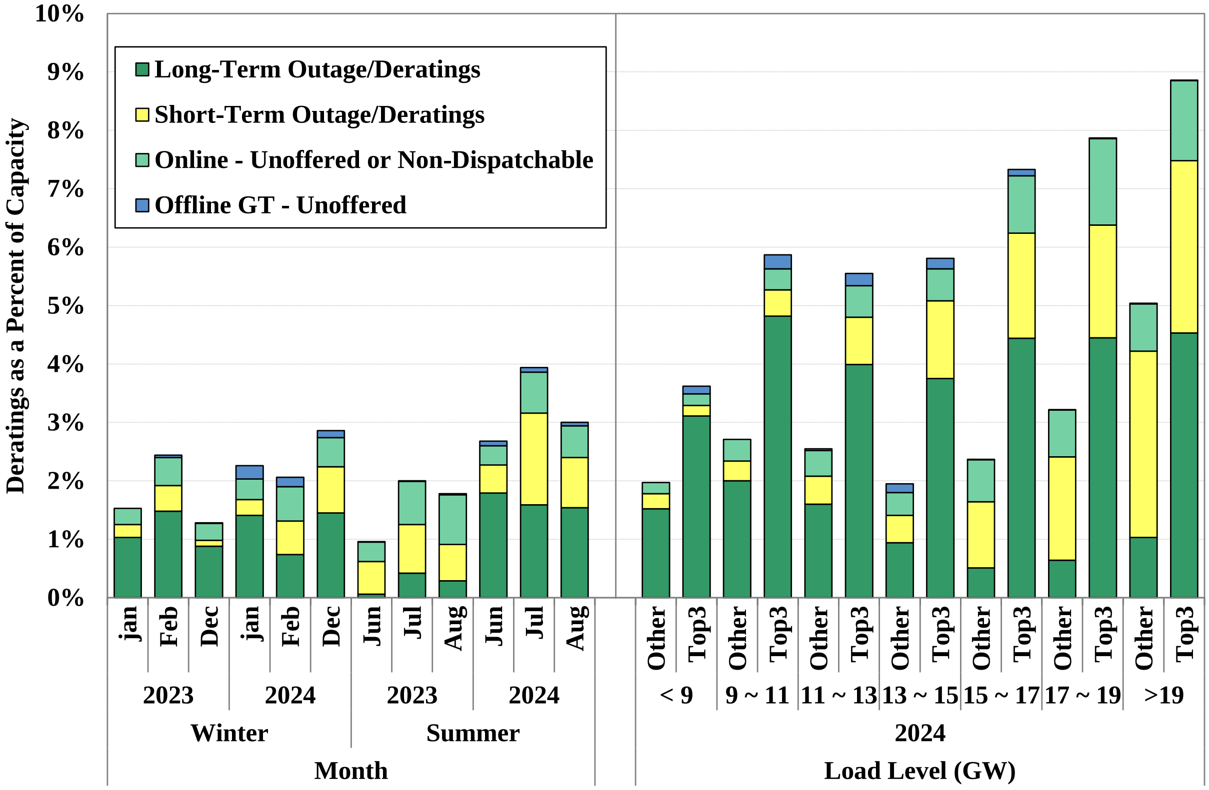
In a competitive market, suppliers have strong incentives to offer their supply at prices close to their short-run marginal production costs. Fuel costs account for the majority of short-run marginal costs for most generators, so the close correspondence of electricity prices and fuel prices is a positive indicator for the competitiveness of the NYISO's markets.

The "supply curve" for energy is relatively flat at low and moderate load levels and steeper at high load levels, which causes prices to be more sensitive to withholding and other anticompetitive conduct under high load conditions. Conditions arise when the supply cost curve becomes steep during periods of low and moderate demand, which could make such periods susceptible to potential anticompetitive conduct as well. Prices are also more sensitive to withholding in transmission-constrained areas where fewer suppliers compete to serve the load and manage the congestion into the area. Hence, our assessment focuses on potential withholding in Eastern New York because it contains the most import-constrained areas and is most susceptible to limitations on natural gas supply during peak winter periods.

In this competitive assessment, Figure 43 evaluates potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. Deratings and outages are shown according to whether they are short-term (i.e., up to seven days) or long-term. Figure 44 evaluates potential economic withholding by estimating an "output gap" which is the amount of generation that is economic at the market clearing price but is not producing output because the supplier's offer parameters (economic or physical parameters) exceed the reference level by a given threshold. Both figures show quantities by season, load level, and the supplier's portfolio size.[180]

[180] Both evaluations exclude capacity from hydro and other renewable generators. They also exclude nuclear units during maintenance outages, which cannot be scheduled when the generator is not economic. Mitigation Threshold refers to the threshold used for statewide mitigation, which is the lower of $100 per MWh or 300 percent of the reference level. Threshold 1 is the 25 percent of the reference level, and Threshold 2 is 100 percent of the reference level. See Appendix Sections II.A and II.B for more details.

Figure 43: Unoffered Economic Capacity in Eastern New York
2023 – 2024



Overall levels of unoffered economic capacity were low but rose modestly in 2024. However, both long-and-short-term outages and deratings increased noticeably among generators in Eastern New York, averaging 7-percent in the largest portfolios during loads above 19 GW. Most of the capacity flagged for short-term outages and derates in peak hours was on combined cycle units in Eastern New York, with conventional steam turbines accounting for much of the remaining capacity flagged. Combined cycles generators tend to be economic in all hours during peak periods so even short-duration outages can create a significant amount of flagged capacity. This summer witnessed more long-term outages as well, especially among combined cycle units. Supply chain issues led several otherwise-economic combined cycles to miss much or all of the peak summer periods while waiting on delivery of parts.

The amount of unoffered economic capacity increased when load levels in the east rose above 17 GW, primarily among suppliers other than the top three. Roughly 12 percent of economic supply was unavailable from the smaller portfolios during the highest load hours (greater than 19 GW) and more than 3 percent of economic supply was unavailable from the Top 3 suppliers. Typically, suppliers with small portfolios are less likely to have incentives to withhold.

In the highest load hours, nearly 20-percent of the unoffered economic capacity of the Top 3 suppliers was unoffered or non-dispatchable capacity from online resources. Notable reasons for online resources not offering their upper output ranges included:

- *Inflexibility of duct-firing capacity* – Some combined cycles offer inflexibly in real-time to manage physical operating constraints on the duct-fired portion of the output range. Currently, the market models treat duct burners as capable of responding to AGC and eligible for 10-minute reserve products; however, duct-firing capacity is generally not flexible enough to provide either of these services.[181] NYISO's 2024 *Improve Duct-Firing Modeling* project is slated to develop a market design to address some of these issues.
- *Ambient conditions* – Capacity ratings for temperature-dependent resources change daily and hourly as ambient conditions vary. Relevant factors include air temperature, relative humidity, inlet water temperatures, and tidal levels. NYISO currently collects unit-specific output factor curves that can be used to adjust for daily ambient air temperature changes, but NYISO does not have comparable information for humidity, inlet water temperatures, and tidal levels, which affect the capability of generators with certain inlet cooling systems and water cooled condensers and make it difficult to quantify the precise amount of capacity unavailable due to ambient conditions.[182]
- *Inability to follow basepoint* – Many older, smaller combined cycle generators upstate never installed the necessary equipment to follow 5-minute dispatch instructions automatically. Consequently, these units usually do not offer flexibly in real-time when committed. While some generators might make the necessary capital improvements to follow dispatch automatically, it is not cost-effective for others.
- *Cogeneration steam demand* – Several cogeneration resources in Eastern New York sell steam under bilateral contracts and sell excess electric generation to the grid. Typically, host steam load takes priority over selling electricity to the grid and, therefore, electric capability from these resources is often derated when host steam demand rises.

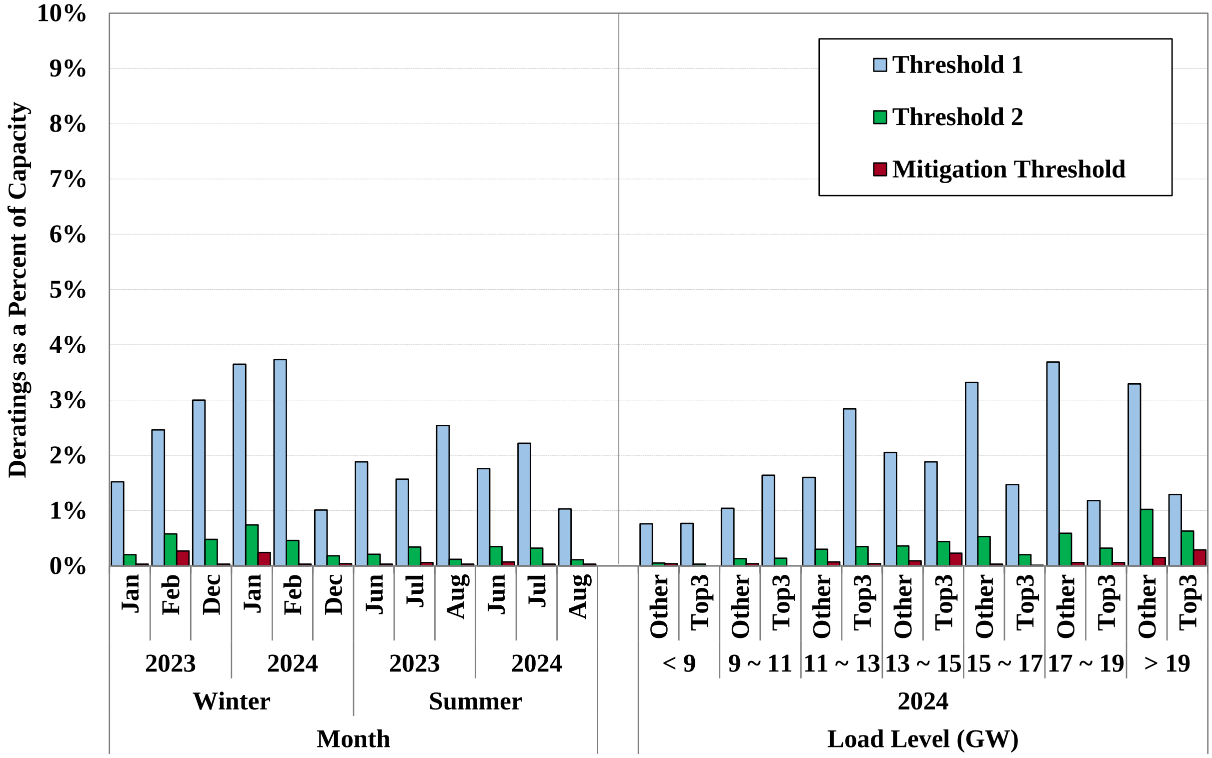
The amount of output gap in Eastern New York remained very low in 2024, averaging 0.05 percent of total capacity at the statewide mitigation threshold and 1.6 percent at the lowest threshold evaluated (i.e., 25 percent above the Reference Level).

The output gap in Eastern New York is usually largest during either high load conditions in summer or in peak winter conditions when fuel prices become volatile. In 2024, the summer and winter were relatively mild in terms of peak load and natural gas prices, respectively. Consequently, output gap at the mitigation threshold-level remained low.

[181] Analysis of the affected capacity is provided in Section VI.C.

[182] Analysis of the affected capacity during the summer is provided in Section VIII.D.

Figure 44: Output Gap in Eastern New York
2023 – 2024



Much of the output gap in 2024 was attributable to units that typically have bid-based reference levels that are lower than the true marginal cost of generation. Thus, a significant portion of the capacity identified as output gap is due to low reference levels rather than inappropriately high energy offers.[183] To limit the potential for excessive mitigation in areas with strict mitigation measures (i.e., New York City), most NYC generators have cost-based Reference Levels.

It is generally a positive indicator that the unoffered economic capacity and the output gap were comparable for top suppliers and other suppliers during high-load conditions when the market is most vulnerable to the exercise of market power. Overall, the patterns of unoffered capacity and output gap were consistent with competitive expectations and, outside of a few isolated cases, did not raise significant concern regarding the exercise of market power.

B. Automated Mitigation in the Energy Market

In New York City and other transmission-constrained areas, individual suppliers are sometimes needed to relieve congestion and may benefit from withholding supply (i.e., may have local

183 NYISO Market Services Tariff Section 23 outlines three types of reference levels that a generator may have. The first type is the bid-based reference level, which is calculated as the average of accepted economic bids during unconstrained intervals over the past 90 days, adjusted for changes in day-ahead gas prices. This approach tends to under-state marginal costs for units that face fluctuating intraday fuel prices.

market power). Likewise, when an individual supplier's units must be committed to maintain reliability, the supplier may benefit from raising its offer prices above competitive levels. In these cases, the market power mitigation measures effectively limit the ability of such suppliers to exercise market power. This section evaluates the use of three key mitigation measures:

- Automated Mitigation Procedure (AMP) in New York City – This is used in the day-ahead and real-time markets to mitigate offer prices of generators that are substantially above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[184]

- Reliability Mitigation in New York City – When a generator is committed for local reliability, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A $0 conduct threshold is used in the day-ahead market and the AMP conduct threshold is used in the real-time market.

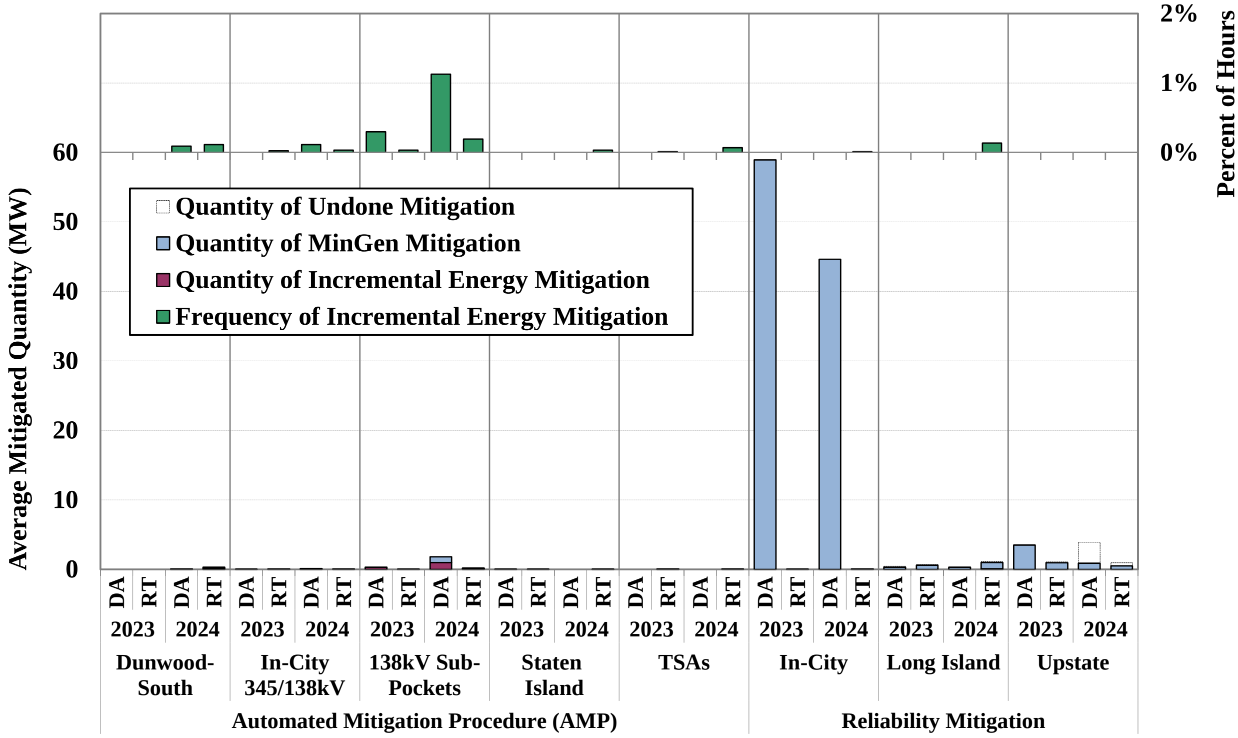
- Reliability Mitigation in Other Areas – When a generator is committed for reliability and the generator is pivotal, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A conduct threshold of the higher of $10 per MWh or 10 percent of the reference level is used.

Figure 45 summarizes the market power mitigation (i.e., offer capping) that was imposed in the day-ahead and real-time markets in 2023 and in 2024. The figure shows that most mitigation occurs in the day-ahead market where most supply is scheduled. Reliability mitigation accounted for roughly 95 percent of all mitigation in 2024, nearly all of which occurred in the day-ahead market. In New York City, the amount of capacity committed for reliability and the frequency of mitigation decreased from 2023 to 2024 due to higher energy prices which made in-city steam units more economic than in prior years. The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have market power.

AMP mitigation accounted for about 5 percent of total mitigation, up from 1 percent in 2023. AMP mitigation only applies when there is an active transmission constraint. Congestion in New York City increased from the prior year in certain load pockets which contributed to higher levels of AMP mitigation.

184 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

Figure 45: Summary of Day-Ahead and Real-Time Mitigation
2023 - 2024



When natural gas prices become volatile, generators frequently use the Fuel Cost Adjustment (FCA) functionality to adjust their reference levels in the day-ahead and real-time markets. This has increased in frequency since the Indian Point units retired and eastern New York has become more reliant on gas-only and dual-fuel units. The FCA functionality is important because it allows a generator to reflect fuel cost variations closer to when the market clears. This helps the generator to avoid being mitigated and scheduled uneconomically.

While it is important to ensure that generators are not mitigated inappropriately, the FCA functionality provides the opportunity to submit biased FCAs that might allow an economic generator to avoid being mitigated. NYISO has considered tariff changes to Attachment H to address the potential for firms to withhold by submitting biased fuel cost adjustments.[185] Such changes would address this potential problem by imposing financial sanctions on generators that submit biased FCAs to withhold capacity, although no such changes have been adopted thus far.

C. Competition in the Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to meet planning reserve margins by providing long-term signals for efficient investment in new and existing

185 See presentation from March 7, 2023 MIWG.

generation, transmission, and demand response. NYISO has market power mitigation measures that are designed to ensure that the markets perform competitively.

Supply-side market power mitigation measures prevent or deter suppliers with market power from inflating prices above competitive levels by withholding economic capacity in these areas. The supply-side mitigation measures work by imposing an offer cap on pivotal suppliers in the spot auction and by imposing penalties on capacity otherwise withheld.[186]

Buyer-side market power mitigation (BSM) measures are used in New York City and the G-J Locality to prevent entities from artificially depressing prices below competitive levels by subsidizing the entry of uneconomic capacity. The BSM measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. Beginning with NYISO's interconnection Class Year 2021, projects considered to contribute to New York state policy ("Excluded Facilities") are not subject to BSM evaluation. Projects that are not Excluded Facilities are exempted from an offer floor if they pass one of four evaluations.[187]

1. Application of the Supply-Side Mitigation Measures

Given the sensitivity of prices in the Mitigated Capacity Zones, the supply-side market power mitigation measures are important for ensuring that capacity prices in these zones are set at competitive levels. From time to time, the NYISO evaluates whether a proposal to remove capacity from a Mitigated Capacity Zone has a legitimate economic justification. We have found that the NYISO's evaluations in recent years have been in accordance with the tariff.

2. Application of the Buyer-Side Mitigation Measures

Class Year 2023, which concluded in December 2024, included intermittent renewables, energy storage, and an HVDC transmission project participating in the state's 'Tier 4' clean energy procurement in the mitigated capacity zones. All of the CY23 projects in the mitigated zones were considered to be Excluded Facilities and therefore not subject to BSM evaluation.

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186 See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

187 A new entrant can receive a BSM exemption under the provisions of: (a) Competitive Entry Exemption, (b) Part A Test Exemption, (c) Part B Test Exemption, and (d) Self-Supply Exemption. See MST Section 23.4.5.7.

XI. Demand Response Programs

Participation by demand response in the market provides numerous benefits, including enhanced system reliability, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in energy consumption by end users during high-price periods can significantly reduce the costs associated with committing and dispatching generation to satisfy system needs. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response. As intermittent generation continues to expand in the coming decades, demand response and price-responsive loads will play an increasingly vital role in helping NYISO maintain security and reliability at the lowest cost.

Demand response programs provide incentives for retail loads to participate in the wholesale market. The Special Case Resource (SCR) program and the Targeted Demand Response Program (TDRP) allow reliability demand response resources to be activated when NYISO or the local Transmission Owner forecasts a shortage. Currently, nearly all of the 1,488 MW of demand response resources registered in New York are reliability demand response resources.[188] The Demand-Side Ancillary Services Program (DSASP) enables economic demand response resources to participate in the ancillary services markets, although this program will sunset on October 31, 2025, and NYISO is encouraging DSASP resources to transition to the Distributed Energy Resource and Aggregation Participation Model.

To facilitate greater consumer engagement, NYISO created the Distributed Energy Resource (DER) and Aggregation Participation Model, which was launched on April 16, 2024. This model enables both individual large consumers and consumer aggregations to participate more actively in the day-ahead and real-time markets, accommodating duration limitations in offers, payments, and obligations.

No resources participated in the DER and Aggregation Participation Model in 2024. The lack of participation in the new DER model is an indication that many existing demand response resources prefer the rules of the SCR and DSASP programs. Future SOM reports will assess the DER model as participation increases and, if participation remains low, discuss potential explanations. Our Recommendation #2024-2 addresses elements of the DER model that may deter participation.[189]

188 In addition, there are demand response programs that are administered by local TOs.

189 See Section I.

Special Case Resources Program

The SCR program is the most important demand response program operated by NYISO with nearly 1.5 GW of resources participating in 2024. The primary incentive for SCR participation is that it allows demand response to sell capacity in NYISO's market. The registered quantity of reliability program resources has steadily increased over the past three years.

In the Summer 2024 Capability Period, SCRs contributed to resource adequacy by satisfying:

- 3.8 percent of the UCAP requirement for New York City (on average);
- 3.3 percent of the UCAP requirement for the G-J Locality;
- 0.5 percent of the UCAP requirement for Long Island; and
- 2.9 percent of the UCAP requirement for NYCA overall.

SCRs are required to respond to activations for at least 4 hours. In the 2023/24 Capability Year, their UCAP MWs were discounted using the Duration Adjustment Factor of 90 percent for 4-hour duration limited resources. Starting in the 2024/25 Capability Year, their UCAP MWs are discounted using the Capacity Accreditation Factor (CAF) for 4-hour resources, which was estimated to be 69 percent in Zone J, 79 percent in Zone K, 68 percent in Zones G/H/I, and 64 percent in Rest of State using a resource adequacy model that estimates the marginal reliability value of each resource type.[190]

Demand-Side Ancillary Services Program

This program allows demand-side resources to offer operating reserves and regulation service in the wholesale market. Currently, twelve DSASP resources actively participate in the market, providing considerable value by reducing the cost of ancillary services in the New York market. Collectively, these resources can provide up to 433 MW of operating reserves. However, at the end of October 2025, NYISO will retire this program and the DER model will provide the only mechanism for demand-side provision of ancillary services.

Demand Response and Scarcity Pricing

In an efficient market, clearing prices should accurately reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under scarcity conditions. NYISO has special scarcity pricing rules for periods when demand response resources are deployed.

In 2024, NYISO activated SCR resources on four days:

- June 20 - in Zone K for localized reliability needs on Long Island.
- July 15, 16 and August 1- in all zones for NYCA-wide capacity needs.

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190 See Section 4.1.1 of ICAP Manual for more details.

Scarcity pricing was not triggered on June 20, partly due to two deficiencies in the reserve market related to Long Island:

- The reserve market requirements are understated relative to the actual reliability needs in Long Island – Recommendation #2024-1 aims to address this by raising the market requirement to align with full reliability need.
- The reserve clearing prices in Long Island do not account for the costs of satisfying the reserve market requirements for Long Island – Recommendation #2019-1 proposes addressing this by setting reserve clearing prices for Long Island that consider all binding reserve constraints in the market scheduling model.

Scarcity pricing was triggered on the other three days when SCRs were activated in all zones, although scarcity pricing was triggered in a small share of intervals. SCRs must be called for a block of hours and all SCRs within the activation zones must be deployed. The inability to moderate the quantity and duration of SCR activations leads to some periods of low price levels during SCR deployments. The DER model is designed to enhance flexibility in demand participation. Future reports will assess its performance as participation increases.

Additionally, demand response resources in local utility programs were activated multiple times throughout the summer of 2024, primarily for peak-shaving in local TOs' servicing areas.[191] While these deployments helped avoid or reduce NYCA capacity deficiencies on several days, their value was not fully reflected in wholesale energy prices, as utility demand response deployments are not currently factored into market scheduling and pricing.[192]

The load reductions from utility-activated demand response is not considered in day-ahead forecasts, which has led to excessive reliability commitments and unnecessary out-of-market actions on high-load days in previous years, although this did not occur in 2024. In addition, the deployed MW is not considered in the current scarcity pricing rules in the real-time market even though it helps avoid reserve deficiencies. To enhance market efficiency, it would be beneficial for NYISO to collaborate with TOs to evaluate the feasibility and appropriateness of including utility demand response deployments in its market scheduling and pricing processes.

191 Utility demand response resources are paid primarily for availability (including capacity). Utility programs often provide large payments (~$1,000/MWh) for peak-shaving that are far above the value of load reduction in the real-time market.

192 See our analysis in *Quarterly Report on the NYISO Markets Third Quarter of 2024*, pages 79-80.

XII. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2024, although we recommend additional enhancements to improve market performance. Twenty-four recommendations are presented in five categories below. A numbering system is used whereby each recommendation is identified by the SOM report in which it first appeared and the number used in that report. For example, Recommendation 2015-16 originally appeared in the 2015 SOM Report as Recommendation #16. The majority of these recommendations were made in the 2023 SOM Report, but Recommendations 2024-1 and 2024-2 are new in this report. The following tables summarize our current recommendations and NYISO market design projects to help address the recommendation that is in the 2025 project plan and/or projected work for 2026 based on the December 2024 version of the Market Vision document (which is available here).

High Priority Recommendations

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
Energy Market Enhancements – Pricing and Performance Incentives			
2015-16	2023 SOM Appx. V.N	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	*Dynamic Reserves:* (Software Design Specs / Development Complete)
2016-1	2023 SOM Appx. V.D	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2024-1	VI.E	Use the reserve market rather than out-of-market actions to satisfy local reserve requirements in New York City, Long Island, and upstate New York load pockets.	*More Granular Operating Reserves:* (- / Market Concept Proposed)
2017-2	VI.A.1	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	N/A
Capacity Market – Design Enhancements			
2021-4	VIII.D	Improve capacity modeling and accreditation for specific types of resources.	*Modeling Improvements for Capacity Accreditation:* (Deployment / -) and *NYISO RA Model Strategic Plan* (see below)
2022-1	VIII.E.1	Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs.	*Valuing Transmission Security:* (Market Concept Proposed)

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
2022-2	VIII.G	Establish seasonal capacity requirements and demand curves.	*Winter Reliability Capacity Enhancements:* (Market Design Complete / Software Design Specs)
2022-4	VIII.C	Implement more granular capacity zones and a dynamic process for updating the zones.	N/A

Other Recommendations

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
Energy Market Enhancements – Pricing and Performance Incentives			
2023-1	VII.D	Allocate congestion residuals to NYTOs based on incremental transfer capability scheduled in the DAM.	*Dynamic Reserves - Review Operating Reserve Supplier Cost Recovery:* (Market Design Concept Proposed / -)
2023-2	VI.B	Modify fast start pricing logic to base Minimum Run Time eligibility criteria on the treatment of the unit rather than the bid.	N/A
2021-1	VI.A.1, VI.E	Evaluate need for longer lead time reserve products to address increasing operational uncertainties.	*Balancing Intermittency: (Phase 1:* Development Complete / *Phase 1:* Deployment & *Phase 2:* Market Design Complete)
2021-3	VII.B	Consider modeling transient voltage recovery constraints on Long Island in the energy market.	N/A
2019-1	XII.B	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.	*Dynamic Reserves:* (Software Design Specs / Development Complete)
2015-9	IX.C	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	N/A
Energy Market Enhancements – Real-Time Market Operations			
2023-3	VI.D	Revise tariff to provide disincentives for over-generation by generators with negative incremental costs.	N/A
2020-1	VI.C	Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more	*Improving Duct-Firing Modeling:* (Development Complete / Deployment)

Number	Section	Recommendation	NYISO Project Scope: (2025 / 2026)
		appropriately reflects its operational characteristics.	
2020-2	VI.A.2	Eliminate offline fast-start pricing from the real-time dispatch model.	N/A
2012-8	Appx. III.I	Operate PAR-controlled lines between New York City and Long Island to minimize production costs and create financial rights that compensate affected transmission owners.	N/A
Capacity Market – Design Enhancements			
2023-4	VIII.E.2	Develop sloped demand curves reflecting the marginal value of surplus capacity for use when an LCR is determined by a Transmission Security Limit.	N/A
2023-5	VIII.G.2	Update market processes to mitigate the risk of extreme pricing caused by inaccuracies in the Winter-Summer Ratio parameter.	N/A
2013-1c	VIII.C	Evaluate locational marginal pricing of capacity (C-LMP) that minimizes the cost of satisfying planning requirements.	N/A
2012-1c	VIII.C.5 VIII.F	Grant financial capacity transfer rights between zones for market-based transmission upgrades that help satisfy planning reliability needs.	N/A
Broad Market Enhancements			
2024-2	XII	Evaluate potential reforms to enhance incentives for demand-side interconnection and participation in the wholesale market.	N/A
Planning Process Enhancements			
2022-3	IV.B.2	Improve transmission planning assumptions and metrics to better identify and fund economically efficient transmission projects.	N/A

This section discusses each recommendation in more detail. The last subsection discusses several prior recommendations that we chose not to include this year.

A. Criteria for High Priority Designation

As NYISO MMU, we are responsible for recommending market rule changes to improve market efficiency. In most cases, our recommendations provide high-level changes, assuming that NYISO will shape a detailed proposal that will be vetted by stakeholders, culminating in a 205 filing to the FERC or a procedural change. In some cases, we may not recommend a particular solution but may recommend NYISO evaluate the costs and benefits of addressing a market issue with a rule change or software change.

In each report, we designate a few recommendations as "High Priority" based on our assessment of their effects on market efficiency or, in some cases, the magnitude of the market or pricing issue. When possible, we quantify a recommendation's benefits by estimating the production cost savings and/or investment cost savings it would produce because these are the most accurate measures of economic efficiency. We focus on maximizing economic efficiency because this will minimize the costs of satisfying the system's needs over the long-term. We do not use other potential measures that focus largely on economic transfers associated with changing prices, such as consumer savings, because they do not measure economic efficiency.

In addition to these considerations, we often consider the feasibility and cost of implementation. Relatively quick or low-cost recommendations generally warrant a higher priority because they produce higher benefit-to-cost ratios. On the other hand, recommendations that would be difficult to implement or involve benefits that are relatively uncertain receive a lower priority.

B. Discussion of Recommendations

Energy Market Enhancements – Pricing and Performance Incentives

2024-1: Use the reserve market rather than out-of-market actions to satisfy local reserve requirements in New York City, Long Island, and upstate New York load pockets. (High Priority)

NYISO is required to maintain sufficient energy and operating reserves to satisfy local (i.e., sub-zone level) reliability needs based on N-1-0, N-1-1, and N-1-1-0 criteria in New York City, Long Island, and other areas of New York State. These local requirements are not satisfied through market-based scheduling and pricing, so it is necessary for NYISO to satisfy local requirements with out-of-market commitments in the majority of hours. The costs of out-of-market commitments are recouped through make-whole payments rather than through market clearing prices for energy and operating reserves. The routine use of make-whole payments distorts short-term performance incentives and longer-term incentives for new investment that can satisfy the local requirements. Furthermore, they undermine incentives for demand-side participation in the wholesale market. Hence, we recommend NYISO implement local reserve requirements in load pockets that are otherwise satisfied with costly out-of-market actions.

We designate this recommendation as High Priority partly because of significant transmission and resource mix changes planned over the next five to ten years. New transmission and the retirement of peaking generation are shifting the locations of reserve-constrained areas, while the interconnection of intermittent renewable generation is leading to larger and more variable operating reserve needs. Localized operating reserve requirements would help NYISO maintain reliability efficiently by providing better incentives for investment in new and existing resources that can provide reserves at a low cost.

Status: NYISO has deferred addressing this recommendation until 2026 when it tentatively plans a market concept proposed for the "More Granular Operating Reserves" project. We also encourage NYISO to consider whether local reserve requirements should consider the loss of multiple generators due to a natural gas system contingency.

2023-1: Allocate congestion residuals to NYTOs based on incremental transfer capability scheduled in the DAM. (Current)

A large share of the cost of maintaining the high voltage transmission system is recovered through the collection of DAM Congestion Revenues and the auctioning of TCCs.[193] TCC auction revenues are allocated to each NYTO in proportion to the value of its transmission facilities in the auctions, while charges are assessed to each NYTO to the extent that outages of its equipment reduce scheduled transfers in the DAM. However, when additional transmission capability is scheduled in the DAM (above what was sold in the TCC auction), the resulting revenues are allocated in proportion to the TCC revenue allocation, regardless of which NYTO's facilities allowed the additional scheduling. Consequently, NYTOs do not recover the actual value of their transmission assets when their assets are not sold in the TCC auctions, which provides incentives to oversell the capability of the transmission system in the TCC auction, leading TCC prices to be depressed relative to DAM congestion prices.

We recommend NYISO revise the allocation of DAM congestion residuals based on changes in scheduled utilization of the transmission system between the TCC auctions and the day-ahead market. This would allow each NYTO to recover the value of transmission scheduled in the DAM even if the capacity was not sold in the TCC auctions.

Status: NYISO is considering in whether to address this issue in the *Dynamic Reserves - Review Operating Reserve Supplier Cost Recovery* 2025 market project.

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193 DAM Congestion Revenues arise from scheduling in the day-ahead market, equaling the shadow price of each constrained facility times the flow scheduled over the facility in the DAM. Transmission Congestion Contracts ("TCCs"), which are auctioned in strips with durations ranging from 1 to 24 months, give the holder the right to receive payments based on congestion in the day-ahead market. Each TCC represents a slice of the value of the transmission system based on scheduling in the DAM.

2023-2: Modify fast start pricing logic to base Minimum Run Time eligibility criteria on the treatment of the unit rather than the bid.

Fast-start pricing is a modeling technique that allows small quick-start resources with high minimum output levels (relative to their maximum output level) to set the clearing price when their capacity is displacing higher-cost resources in the DAM and RT markets. Resources are eligible to set price if they can be started in 30-minutes or less and they have a 1-hour minimum run time. Currently, by offering to start in 30-minutes or less in the real-time market, a generator agrees to be treated as having a 1-hour minimum run time, even if it has submitted an offer with a longer minimum run time.[194] Nonetheless, quick-start resources that submit an offer with a Minimum Run Time of more than one hour are treated as ineligible to set price as a Fast-Start Resource (even though they are treated as having a 1-hour minimum run time for scheduling purposes) in the real-time market.

We recommend NYISO revise the fast-start pricing logic to base eligibility on the minimum run time used for scheduling rather than the value of the offer parameter that is currently ignored for scheduling purposes by the real-time scheduling system. We believe this change can be made without modifying the tariff since the current tariff language bases eligibility criteria on the minimum run time that a unit "has" rather than the Minimum Run Time offer submitted. [195]

2021-1: Evaluate need for longer lead time reserve products to address increasing operational uncertainties. (Current Effort)

The NYISO currently operates markets for 30-minute, 10-minute and 10-minute spinning operating reserves. These products provide the system flexibility to respond to unexpected contingencies in real time by converting reserve suppliers to energy with relatively short notice. There is a growing set of possible situations where larger quantities of reserves are needed over longer time horizons. For example, generators are routinely committed out-of-market in New York City load pockets to satisfy multiple contingency requirements that could be satisfied by resources with longer response times. In the long term, entry of intermittent renewables is expected to lead to large deviations of net load from the forecast over multiple hours. Procuring some of the additional reserves from resources with longer response times would allow NYISO to cost-effectively maintain security and reliability in these situations, since a larger set of resources can provide reserves over longer time intervals. It would also allow these out-of-market actions to be priced more efficiently to the extent that these actions could occur through the market by deploying a longer-lead time reserve product.

194 NYISO MST 4.4.1.4 states: "RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a minimum run time…not longer than one hour;"

195 NYISO MST 2.6 defines "Fast-Start Resource: A Generator that…(3) has a minimum run time of one hour or less…"

We recommend that NYISO evaluate the need for longer lead time reserve products of up to four hours. While the existing reserve products are designed to satisfy contingency reserve needs (i.e., being prepared for the occurrence of specific unforeseen events), longer lead time reserves are needed for dispatch in case load or intermittent generation deviate significantly from the forecasted level. Thus, longer lead time reserves would be scheduled and deployed differently from the existing contingency reserve products. Longer lead time reserve products could allow NYISO to address reliability needs more efficiently and avoid the use of out of market commitments to secure against multi-hour net load ramps. This would also provide better incentives for building and maintaining flexible resources that help integrate renewables. This evaluation should also consider the impact of energy limitations on a resource's eligibility to provide reserves over a given timeframe.

Status: In the 2024 *Balancing Intermittency Phase 1* project developed a market design concept proposal, which will use existing reserve products to satisfy new Uncertainty Reserve Requirements for net load and renewable generation forecast error. *Phase 2* will define new 1-hour and 4-hour products for longer time frames. *Phase 1* is planned for deployment in 2026, and *Phase 2* is planned for deployment in 2029.

2021-3: Consider modeling transient voltage recovery constraints on Long Island in the energy market.

Transient voltage recovery (TVR) criteria for the East End of Long Island are not represented in the market software, so TVR criteria is frequently satisfied by scheduling generation out-of-market during the summer. This sometimes leads to inefficient generation scheduling and fails to provide efficient incentives to resources that can contribute to satisfying TVR criteria. Hence, we recommend that NYISO satisfy these criteria in the day-ahead and real-time markets using surrogate constraints, so that generation scheduled to satisfy TVR criteria for the East End of Long Island are compensated appropriately. Appendix III.E illustrates how surrogate constraints could be used to satisfy TVR criteria within the market models.

2019-1: Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island. (Current Effort)

The day-ahead and real-time markets schedule resources to satisfy reserve requirements, including specific requirements for 10-minute spinning reserves, 10-minute total reserves, and 30-minute total reserves on Long Island. However, reserve providers on Long Island are not paid reserve clearing prices corresponding to these requirements. Instead, they are paid based on the clearing prices for the larger Southeast New York region. Compensating reserve providers in accordance with the day-ahead and real-time scheduling decisions would improve incentives in the day-ahead and real-time markets, and it would also provide better signals to new investors over the long term.

Status: NYISO plans to address this recommendation through the planned *Long Island Reserve Constraint Pricing* project in 2027 along with the deployment of *Dynamic Reserves*, which will include the capability to dynamically procure reserves on Long Island.[196]

2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability. (High Priority)

Shortage prices during operating reserve deficiencies are currently too low to adequately encourage market participants to take actions that preserve reliability during critical conditions. This is because the demand for operating reserves in the market does not fully reflect their value in ensuring the load is served, or the value-of-lost-load (VOLL). In addition to failing to schedule resources and incent resource actions that will help avoid load-shedding in the short-term, this reduces the incentive to replace inflexible and poor-performing resources with fast-ramping generation and storage in the longer-term. The shortage prices are also sometimes too low to schedule available resources that are needed to satisfy reliability requirements, which compels operators to resort to out-of-market actions to satisfy the requirements.

This problem is exacerbated by the implementation of PFP ("Pay For Performance") rules in ISO New England and PJM, which result in much higher incremental compensation for energy and reserves during reserve shortages in NYISO's neighbors. Resources selling into ISO-NE and PJM receive over $4,000 per MWh during even slight shortages of 10-minute and 30-minute reserves, while NYISO sets prices between $750 and $3,000 per MWh during *deep* 10-minute and 30-minute shortages. This results in inefficient imports and exports during tight regional conditions, negatively affecting NYISO's reliability as energy is drawn to neighboring markets even when shortages in NYISO are much deeper.

Hence, we recommend that the NYISO modify its operating reserve demand curves to provide efficient incentives and ensure reliability during shortage conditions. The values of operating reserve demand curve steps should be targeted so that:

- Clearing prices rise to levels that are efficient given the VOLL and the risk of load shedding given the depth of the reserve shortage;
- The incentive effects of neighbors' PFP rules are minimized;
- The real-time market schedules available resources so that NYISO operators do not need to engage in out-of-market actions to maintain reliability, and
- NYISO real-time scheduling models prioritize appropriately when multiple reserve requirements and/or transmission constraints are simultaneously in shortage.

196 See *Long Island Reserve Constraint Pricing*, presented to the Market Issues Working Group on February 7, 2024.

This recommendation is high priority because the need for resources to be responsive to emergency conditions in real time will become increasingly important. The entry of intermittent renewables and retirement of conventional generators is likely to increase net load forecast uncertainty and create new operational challenges. This recommendation will improve incentives for generation and load flexibility and efficient usage of regional resources to preserve reliability. The costs of increasing operating reserve demand curves would be offset by a corresponding reduction in capacity market demand curves.

2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief. (Current Effort, High Priority)

The NYISO is required to maintain flows such that if a contingency were to occur, no transmission facility would be loaded above its Long-Term Emergency (LTE) rating post-contingency. In some cases, the NYISO is allowed to use operating reserves and other post-contingency operating actions to satisfy this requirement. This allows the NYISO to increase utilization of the transmission system into load centers, thereby reducing production costs and pollution in the load center. Since these operating reserve providers are not compensated for helping manage congestion, the market does not provide efficient signals for investment in new and existing resources with flexible characteristics. Hence, we recommend the NYISO evaluate means to efficiently compensate operating reserves that help manage congestion.

New York City is expected to lose most of its peaking generation over the next three years and it is important for the NYISO market to provide efficient signals for new investment. Some of the retiring peakers are currently utilized for thousands of hours per year to manage congestion by providing offline reserves, which reduces production costs and allows higher levels of imports to New York City. If reserve providers are not compensated in a manner that is consistent with their value, it is less likely that new investors will place resources in areas that relieve congestion and that new resources will have flexible operating characteristics. This will become more important as new intermittent generation is interconnected to the New York City transmission system in the coming years because this will lead to additional variability in congestion patterns.

Status: NYISO plans to address this recommendation with the deployment of *Dynamic Reserves* in 2027.[197]

2015-9: Eliminate transaction fees for CTS transactions at the PJM-NYISO border.

The efficiency benefits of the Coordinated Transaction Scheduling (CTS) process with PJM have generally fallen well short of expectations since it was implemented in 2014. We have observed far greater utilization of CTS bidding at the ISO-NE interface since it was implemented in 2015. The lower utilization of CTS with PJM is due partly to the relatively large fees that are charged

[197] See *Dynamic Reserves*, presented to the Market Issues Working Group on January 25, 2024.

to these CTS transactions, while fees were eliminated between ISO-NE and NYISO. We estimate that the collection of export fees from CTS transactions was $0.7 million in 2023 because the high export fees were usually higher than the expected profits from exporting to PJM. Thus, a lower export fee could result in an overall higher collection of fees because it would allow CTS transactions to be profitable under a wider range of conditions. It is unlikely that CTS with PJM will function effectively as long as transaction fees and uplift charges are large relative to the expected value of spreads between markets. In addition, during periods when surplus renewable generation in upstate New York cannot be delivered to downstate areas due to transmission constraints, export fees for CTS transactions will impose significant costs on renewable generators that export surplus power, which will tend to increase REC costs for ratepayers in the long run.

We recommend eliminating transaction fees and uplift charges on CTS transactions between the PJM and NYISO. It would be beneficial for NYISO to eliminate transaction fees for CTS transactions regardless of whether PJM does the same.

2015-16: Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources. (Current Effort, High Priority)

The amount of operating reserves that must be held on resources in many local areas can be reduced when there is unused import capability into the areas. In many cases, it is less costly to produce more energy from resources in an area, reducing the flows into the area and treating the unused interface capability as reserves. We recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each requirement.

In some cases, the operating reserve requirements above could be satisfied with resources having lead times longer than 30 minutes (rather than 10-minute and 30-minute reserve providers). Accordingly, we have recommended that the NYISO evaluate the need for longer lead-time reserve products (see Recommendation 2021-1). Before longer lead time reserve products have been created, the most efficient way to represent such requirements may be with a 30-minute reserve requirement in the market models. NYISO should consider these tradeoffs in its evaluation of Dynamic Reserves.

This recommendation is a high priority because it will enable NYISO to schedule and price operating reserves efficiently as it implements other high priority recommendations. This will become more important as the New York resource mix evolves over the coming decade.

Status: NYISO is working toward deployment of Dynamic Reserves in 2027, although we have raised concerns with elements of the proposal.[198]

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[198] See *Summary of MMU Comments on NYISO's Dynamic Reserve Market Design Proposal*, Dec. 2024, here.

<u>Energy Market Enhancements – Real-Time Market Operations</u>

2023-3: Revise tariff to provide disincentives for over-generation by generators with negative incremental costs.

Control area operators maintain system security by re-dispatching generation up and down to match load throughout the day. Good utility practice requires generators to make reasonable efforts to adhere to dispatch instructions given the physical limitations of their equipment. To support good utility practice, the NYISO imposes over- and under-generation penalties on generators to ensure they are incentivized to follow dispatch instructions. Units that over-generate by more than three percent of their upper operating limit are penalized by: (i) not receiving LBMP revenue for production above the three percent level if the LBMP is positive and being paid the LBMP when it is negative, and (ii) incurring a small share of the regulation capacity costs in that interval. For generators that incur positive incremental costs to increase output, this over-generation penalty is sufficient to motivate adherence to dispatch instructions because the penalty ensures they will benefit financially from following the instruction. However, for generators with negative incremental costs, this penalty is sometimes not sufficient to motivate them to obey dispatch instructions because they may still benefit financially from not following the instruction to within the three percent level. Consequently, NYISO must sometimes maintain security by curtailing other nearby renewable generators that do follow dispatch instructions consistently. We recommend NYISO work with stakeholders to revise the over-generation penalties to ensure that generators with negative incremental costs do not benefit from over-generating.

2020-1: Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflects its operational characteristics. (Current Effort)

Generators with duct firing capacity are able to offer it into NYISO's real-time market as a portion of the dispatchable range of the generator. However, duct-firing capacity is not always capable of following a 5-minute dispatch or 10-minute reserve deployment signal. The process of starting-up and shutting-down duct burners may take longer than five minutes. For this reason, many generators with duct-firing capability do not offer it into the real-time market, while others "self-schedule" this capacity inflexibly. There is approximately 900 MW of duct-firing capacity in the NYCA, so this enhanced scheduling capability could significantly increase the availability of operating reserves, which will become more valuable as older peaking units retire over the next three years. We recommend NYISO schedule these units in a manner that reflects their actual ability to respond to system conditions.

Status: NYISO developed a proposal to partially address this recommendation in its *Improve Duct Firing Modeling* project in 2023. NYISO plans to deploy the design in 2026.

2020-2: Eliminate offline fast-start pricing from the real-time dispatch model.

NYISO's real-time market runs a dispatch model that updates prices and generator schedules every five minutes. Currently, the dispatch model treats 10-minute gas turbines (i.e., units capable of starting up in ten minutes) as if they can follow a 5-minute signal. However, since 10-minute gas turbines are unable to respond in five minutes, the units routinely receive schedules they are incapable of following. This leads to periods of under-generation, inconsistencies between scheduled transmission flows and actual flows, and inefficient prices that do not reflect the balance of supply and demand. We recommend that NYISO eliminate the feature which is known as offline fast-start pricing.

2012-8: Operate PAR-controlled lines between New York City and Long Island to minimize production costs and create financial rights that compensate affected transmission owners.

Significant efficiency gains may be achieved by improving the operation of the PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines). These lines are scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets.

In 2023, these lines were both scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 96 percent of the time. We estimate that their operation increased production costs by $10 million. Furthermore, we estimate that their operation increased New York State emissions of carbon dioxide by 0.8 percent (260 thousand tons) and nitrous oxide by 6 percent (454 tons).[199]

In 2024, the inefficient operation of these lines was greatly reduced because lengthy transmission outages frequently prevented the lines from being used to flow power in the inefficient direction, resulting in a day-ahead market congestion revenue *surplus* of $9.4 million.[200]

We recommend that NYISO work with the parties to the underlying wheeling agreements to explore potential changes to the agreements or to identify how the agreements can be accommodated within the markets more efficiently. Since more efficient operation would benefit one party financially at the expense of the other, it is reasonable to create a financial settlement mechanism to compensate the party that would be giving up some of the benefits from the current operation. We discuss such a mechanism in Section III.I of the Appendix.

199 See Section V.F in the Appendix.

200 See Section VII.A.

Capacity Market – Design Enhancements

2023-4: Develop sloped demand curves reflecting the marginal value of surplus capacity for use when an LCR is determined by a Transmission Security Limit.

The shape of the sloped demand curves was developed when the IRM and LCRs were normally based on probabilistic resource adequacy criteria. The slope of the demand curve reflects that the marginal reliability value of capacity declines but remains positive as the amount of surplus capacity rises. In recent years, the LCRs have frequently been based on transmission security criteria, which is deterministic in that it does not explicitly quantify the contribution to reliability of surplus supply in conditions more extreme than the specific planning criteria. The same sloped demand curves are used regardless of whether the LCRs are based on resource adequacy or transmission. It would be beneficial to develop sloped demand curves that reflect the value of additional capacity for transmission security. We recommend NYISO develop sloped demand curves for capacity zones with TSL-based LCRs that reflect the value of surplus capacity given the expected load forecast uncertainty and random variations in the availability of generating capacity.

2023-5: Update market processes to mitigate the risk of extreme pricing caused by inaccuracies in the Winter-Summer Ratio parameter.

NYISO has recognized that as New York transitions from being a summer-peaking system to one with significant winter reliability risk, it will need to develop a fully seasonal capacity market with a complete set of auction parameters for summer and winter conditions. (See discussion below of Recommendation 2022-2.) However, it will take several years to develop a fully seasonal capacity market, and NYISO currently does not expect to implement this before 2028.[201] The current capacity market is based on a mix of annual and seasonal parameters, requiring that some winter auction parameters be based on information from the summer. We have determined that extreme pricing outcomes could arise during the winter if there are large inconsistencies between the UDR elections in the IRM study and the quantities sold from the UDRs during the winter months. The currently backward-looking winter-summer ratio calculation will also fail to promptly reflect major changes in the seasonal supply mix. As a result, revenues to the reference technology could significantly exceed the Net CONE when summer surplus in a capacity zone is at the tariff-prescribed level of excess. Therefore, we recommend NYISO develop this aspect of the seasonal capacity market on an expedited schedule (by the 2026/27 Capability Year) to avoid the possibility of extreme capacity pricing outcomes in the winter months.

201 The 2024 Market Vision plans for deployment of *Winter Reliability Capacity Enhancements* in 2027.

2022-1: Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs. (High Priority, Current Effort)

NYISO determines Locational Capacity Requirements (LCRs) annually using the "LCR Optimizer" method, but the LCRs are subject to a minimum floor in each locality that is designed to respect transmission security criteria. NYISO has recently taken steps to align its calculation of Transmission Security Limits (TSLs) that are used in the LCR process with the methodology used in its reliability planning studies. This has resulted in LCRs being set at the TSL-based floor in multiple localities, and the importance of the TSLs is expected to grow.

Some resources, including large-contingency resources and Special Case Resources (SCRs), are assumed to provide limited value for meeting transmission security planning requirements. SCRs are not counted as helping satisfy transmission security requirements, while large supply resources constituting one of the two largest in a given area tend to increase the capacity requirement in the area. For example, in New York City, individual supply resources larger than 700 MW generally increase the capacity requirement in the city. Consequently, the presence of these resources causes LCRs to increase when set by the TSL methodology. This causes consumer costs to increase and undermines efficient incentives for investment, because some suppliers receive payment based on requirements which they do not help to resolve. To address this, we recommend adjusting the capacity payments to resources based on their contributions to meeting the underlying resource adequacy and transmission security requirements.[202] For large-contingency resources, this recommendation should not apply to the portion of the unit that does not cause an increase in the Transmission Security Limit.

Status: The 2024 Market Vision states that NYISO plans to evaluate in 2026 "how best to include transmission security needs in the wholesale market" in the *Valuing Transmission Security* project.

2022-2: Establish seasonal capacity requirements and demand curves. (High Priority, Current Effort)

NYISO's capacity market uses the same installed capacity requirements in all months of the year. The level of surplus supply in each spot capacity auction is determined by the amount of installed capacity relative to this annual requirement. This usually bears little relationship to actual seasonal reliability risk, which is determined by seasonally available supply (considering resource deratings) and seasonal load levels. As a result, seasonal prices are determined by the level of installed capacity (regardless of its actual availability) and may fail to provide incentives

202 See discussion in Section VIII.E. This will require the NYISO to determine what the LCR would be if there was no TSL requirement so that it can determine a resource's contribution to satisfying resource adequacy needs.

that correspond to seasonal reliability risk. Furthermore, the process for setting annual requirements may be poorly-suited to the timeframe required for winter fuel procurement decisions. Hence, we recommend considering implementation of separate seasonal capacity requirements and demand curves that would reflect the level of supply needed to maintain reliability in each season.

NYISO modified to its capacity market demand curves to establish separate seasonal values for the reference point (i.e., the price when supply is equal to the requirement) considering the expected proportion of reliability risk in each season. This proposal is an improvement which will better align prices with expected reliability risk when the system is at its tariff-prescribed level of excess. However, because the level of surplus in each auction will still be determined based on installed capacity compared to a single annual requirement, prices will fail to send efficient incentives to maintain reliability in many circumstances. Hence, we recommend moving to a capacity market with separate seasonal requirements, demand curves, and other parameters.

Status: The 2024 Market Vision states that NYISO plans to deploy market design changes in 2027 under the *Winter Reliability Capacity Enhancement* project.

2022-4: Implement more granular capacity zones and a dynamic process for updating the zones. (High Priority)

NYISO's capacity market has four pricing zones in which all suppliers are paid the same capacity price. However, the marginal value of capacity differs by location due to internal transmission constraints within each of the current capacity zones. For example, bottlenecks limit the deliverability of capacity in Staten Island to the rest of New York City, but Staten Island suppliers are paid the premium New York City price. This results in inflated consumer payments and reduces incentives to retain capacity in areas where there are reliability needs or to retire capacity in areas with oversupply. Furthermore, the deliverability planning process places inefficiently high transmission upgrade costs on some new project developers, which acts as a barrier to new entry in some areas. NYISO's current tariff-defined zone creation process is not capable of creating new capacity zones in a timely manner.

Hence, we recommend implementing and dynamically updating an expanded set of capacity zones that will reflect the known bulk transmission bottlenecks on the NYISO system. This process would establish requirements for all load zones and designated sub-zone areas using the LCR Optimizer method. It would price capacity using demand curves for regions with binding transmission constraints in NYISO's resource adequacy model GE-MARS. As part of this process, it will be necessary to define export demand curves for regions that have surplus capacity and face transmission bottlenecks.

Because no configuration of zones will accurately reflect the key constraints that separate areas from a planning perspective, the recommendation also includes a proposed capacity constraint pricing (CCP) component that would be applied in capacity settlement. This is an incremental locational price adder that would ensure that the economic signals for each resource reflects its effects on the key planning constraints.

This recommendation is high priority because: (1) significant overpayment by consumers is already occurring due to overpricing of export-constrained areas, (2) coming changes in reliability needs (such as the growing importance of winter reliability) make it critical for the capacity market to be able to accurately signal the value of retaining and attracting capacity where it is needed, and (3) there are inefficient barriers to new entry in areas where generation is not fully deliverable within one of the existing four capacity zones.

Status: The 2024 Market Vision states that NYISO plans to begin working on market design changes in 2027 for deployment in 2029 under the *Granular Capacity Zones* project.

2021-4: Improve capacity modeling and accreditation for specific types of resources. (High Priority, Current Effort)

NYISO implemented a new capacity accreditation framework in the 2024/25 Capability Year, which compensates resources according to their marginal contribution to reliability. For each Capacity Accreditation Resource Class (CARC), this contribution is reflected in its Capacity Accreditation Factor (CAF), which is calculated based on the impact of an incremental amount of that resource type on the reliability metric (e.g. LOLE) in NYSRC's resource adequacy model GE MARS. These changes establish a framework for efficiently compensating resources in the capacity market based on their impact on resource adequacy. However, limitations in current MARS modeling techniques may prevent some resource types from being evaluated as accurately as possible:

a) Winter fuel limitations – NYSRC is evaluating how to model in MARS limits on the output of gas-fired units without backup fuel that are jointly unavailable during extreme cold weather for the 2026/27 Capability Year;
b) Energy storage modeling – MARS uses a simplified method to dispatch energy limited resources that could better reflect strategic dispatch under imperfect foresight and the tendency for energy storage resources to be scheduled for 10-minute reserves;
c) Resource/Load Correlations – MARS models renewable output shapes independently of load shapes, but these are correlated in practice because both are driven by weather;
d) Inflexible Resources – MARS does not accurately model the availability of inflexible units with long startup lead times because it assumes they are always committed and available; and
e) Conventional Generators Receiving Excessive Credit – Several categories of generation receive excessive credit under current capacity market rules, including (i) generators affected by ambient water temperature, humidity, and barometric pressure conditions

under peak summer conditions, (ii) emergency generating capacity that is unreliable or cannot be deployed in real-time with the existing market software, and (iii) generators receiving EFORd values that overstate their reliability in critical hours due to frequent off-peak operation.

We recommend that NYSRC and NYISO consider improvements to more accurately evaluate marginal reliability contributions for: (a) gas-only generators with limited/no backup fuel, (b) energy limited resources, (c) resources whose availability is correlated with load, and (d) inflexible generators, and (e) conventional generators receiving excessive capacity credit. For generators with limited backup fuel, it is necessary to model fuel inventory constraints because MARS does not evaluate the potential for oil-fired and dual-fuel units with limited on-site fuel to deplete their inventories during winter cold snaps.

Status: NYISO and NYSRC have already made significant progress towards addressing this recommendation in the following ways:

a) Winter fuel limitations – Starting with the 2026/27 Capability Year, the IRM Study and the capacity market will distinguish between firm and non-firm gas-fired generators.
e) Conventional Generators Receiving Excessive Credit – Starting with the 2025/26 Capability Year, the NYISO will:
    - Reduce the excessive credit to generators affected by ambient water temperatures,
    - Properly account for ambient humidity impacts, and
    - Place limits on the ability of generators to designate capacity as available only during emergencies.

In addition, NYISO and NYSRC are actively working to assess potential improvements to energy storage modeling, winter load shapes, and correlations among weather-dependent resources and loads.[203] We support NYISO and NYSRC's continuing efforts to place a high priority on incorporating these changes in IRM studies.

2013-1c: Evaluate locational marginal pricing of capacity (C-LMP) that minimizes the cost of satisfying planning requirements.

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The demand curve reset process sets the capacity demand curve for each locality relative to the IRM/LCR without fully considering whether this results in a consistent relationship between the clearing prices of capacity and the marginal reliability value of capacity in each Locality. Reliance on four fixed capacity zones will also prevent the current market from responding to significant resource additions, retirements, or transmission network changes.

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203 See NYSRC IRM Model Proposed Whitepaper Scopes 2025, presented by NYISO to NYSRC Installed Capacity Subcommittee on January 8, 2025, available here.

We recommend the NYISO evaluate a capacity pricing framework where the procurements and clearing price at each location is set in accordance with the marginal reliability value of capacity at the location. Our proposed Locational Marginal Pricing of Capacity (C-LMP) would eliminate the existing capacity zones and clear the capacity market with an auction engine that will include the planning criteria and constraints. This will optimize the capacity procurements at locations throughout the State, and establish locational capacity prices that reflect the marginal capacity value at these locations.

This recommendation would produce sizable economic and reliability benefits over the long term. In particular, it would reduce the costs of satisfying resource adequacy needs, facilitate efficient investment and retirement, be more adaptable to changes in resource mix (i.e., increasing penetration of wind, solar, and energy storage), and simplify market administration.

2012-1c: Grant financial capacity transfer rights between zones for market-based transmission upgrades that help satisfy planning reliability needs.

This is similar to the NYISO's current rules to provide Transmission Congestion Contracts (TCCs). New transmission projects can increase transfer capability over interfaces that bind in the NYISO's capacity market. Hence, transmission projects can provide resource adequacy and transmission security benefits that are comparable to capacity from resources in constrained areas. Accordingly, transmission should be compensated for the resource adequacy and transmission security benefits through the capacity market. Creating financial capacity transfer rights will help: (a) provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives, and (b) reduce barriers to entry that sometimes occur under the existing rules when a new generation project is required to make uneconomic transmission upgrades.

Broad Market Enhancements

2024-2: Evaluate potential reforms to enhance incentives for demand-side interconnection and participation in the wholesale market.

For more than a decade, electric load growth has been flat or even negative throughout much of the U.S. as energy efficiency improvements and behind-the-meter solar generation have offset demand growth. However, as these trends wind down, the rate of electricity demand growth is expected to rise because of heating electrification, electric vehicle adoption, and the interconnection of new large loads such as data centers. These trends pose significant challenges for centralized wholesale markets such as NYISO, which are responsible for using efficient market incentives to maintain security and reliability in the operations and planning time horizons, facilitating swift interconnection of new supply and load, and adapting to the loss of existing generation resulting from environmental policies.

These trends will require the centralized wholesale markets to make significant reforms in multiple areas in the coming years. One major area in need of reform encompasses the processes and incentives for demand-side interconnection and participation in the wholesale market. Such reforms would help soften the impact of large-scale changes in electric supply and demand. Regulators have sought to promote mechanisms for demand-side participation and facilitate new energy-intensive investments such as data centers.[204] NYISO has taken a number of steps to improve demand-side access to wholesale market, but significant effort is still needed in key areas.

First, NYISO has sought to transition capacity-selling loads from the SCR program (which is an emergency demand response program) to the new DER participation model, but the current rules impose significant burdens on DERs beyond what is required for generators that sell capacity. For example, generators are able to satisfy their capacity obligation by offering into the day-ahead market with a start-up notification time, minimum-run time, and start-up cost to ensure the generator will recoup its commitment costs if scheduled. However, DERs can only sell capacity if they are willing to be curtailable with little notice and without the ability to recoup commitment costs with minimum duration or commitment cost parameters.

Second, NYISO's planning department has recognized that a large portion of new load interconnections will not require firm service because they will be energy-intensive businesses that seek low-cost energy and rapid interconnection but do not have the typical need for reliability.[205] Some such businesses can simply shift consumption away from periods of tight supply, while others will prefer to maintain reliability with their own onsite back-up generation rather than NYISO system resources. However, NYISO's interconnection process does not have distinct rules for non-firm load customers, so large load customers that are willing to be curtailable are subject to the same interconnection costs and procedural timelines as customers seeking firm service.

Third, the cost of building and maintaining the high-voltage transmission system is not fully recouped from the sale of TCCs and congestion rents from the day-ahead market, so transmission service charges are used to recoup the remaining embedded costs. While transmission service charges are allocated on a volumetric (i.e., per MWh) basis to LSEs and exports, the cost of the transmission system is primarily driven by the planning requirements of the system, which are driven by the amount of firm load under peak conditions. Hence, the current practice of recouping the net cost of the transmission system with a volumetric charge places excessive cost burdens on loads that are curtailable and/or consume proportionally more under mild and/or moderate system conditions, while under-charging loads that have firm needs

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204 Examples include Commission Order 2222 and its Docket AD24-11-000 addressing "Co-location of Large Loads at Generating Facilities."

205 For example, see NYISO's *2024 Reliability Needs Assessment*, pages 13 and 34-37.

under peak conditions in areas of the system where capital projects are needed to maintain reliability. Consequently, the current volumetric transmission rate design does not provide efficient incentives for new investment in energy-intensive businesses.

Fourth, in an effort to bolster incentives for demand-side participation in the wholesale market, the Commission issued Order 745 in 2011, which required centralized wholesale markets to pay the "full LMP" to demand response resources to curtail in response to an operator instruction.[206] This well-intentioned but misguided mandate ignored the cost savings that loads realize when they do not consume electricity. Consequently, centralized markets do not have a balance between charges to buyers and payments to sellers when demand response resources are involved, resulting in uplift charges.[207] These uplift charges have been acceptable when demand response resources were called for five to ten hours per year under peak conditions, but frequent participation by demand response resources will eventually lead to unsustainably-large uplift charges for the rest of the market.[208]

These issues will distort incentives for demand-side participation and undermine the benefits to the overall market. Hence, we recommend NYISO evaluate these concerns and consider potential reform. In addition, it would be beneficial for the Commission to reexamine the Order 745 mandate to pay demand response resources the LMP even when they realize a cost reduction from not consuming.

<u>Enhance Planning Processes</u>

2022-3: Improve transmission planning assumptions and metrics to better identify and fund economically efficient transmission projects.

In recent years, NYISO transmission planning has been driven solely by the need to integrate expected future renewable resources under the Public Policy Transmission Process (PPTP). The NYISO's Economic Planning Process focuses on long-term informational forecasting of the resource mix and congestion patterns (in the Outlook) that forms the basis for eventual evaluation of projects in the PPTP. Deficiencies in the methodology used for evaluating benefits may cause NYISO-led solicitations for public policy transmission to select a project that fails to

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206 See Commission Order 745, dated March 15, 2011, Docket No. RM10-17-000. Throughout the record, the term "full LMP" is used as a euphemism for paying a demand response provider for load reduction even though it is avoiding a charge for consumption.

207 For example, if a market has 100 MW of generation serving 100 MW of load at an LBMP of $30 per MWh, the loads will pay out $3,000 per hour and the generators will receive $3,000 per hour. If a DR provider provides 1 MW of load reduction, total generation and load will be reduced to 99 MW, but loads will have to pay for 100 MW of "supply" including 99 MW of generation and 1 MW of DR. Consequently, the 99 MW of remaining load customers will each pay $0.30 per MWh of uplift in addition to the $30 LBMP.

208 Demand response activation will be paid the LBMP in hours when it exceeds the Monthly Net Benefits Threshold ("MNBT"), which is likely to occur for hundreds or thousands of hours per year. See here.

efficiently address the underlying need or that is not the best among competing projects. In this report, we recommend the following enhancements that will lead more cost-effective projects to be selected in future solicitations:

d) Update the methodology of the Outlook study to better account for market incentives of renewable and storage resources;
e) Evaluate economic and PPTN projects using a project case that considers changes to the resource mix resulting from the Project's inclusion; and
f) Estimate transmission project benefits based on their NYISO market value.

C. Discussion of Recommendations Made in Previous SOM Reports

During the development of each State of the Market Report, we review the progress that has been made toward the evaluation and/or implementation of recommendations made in previous reports. Normally, we remove a recommendation from the list if NYISO has responded to the substance of the recommendation by modifying an operating practice or by filing market rule changes and the Commission has accepted them (or they are largely uncontested). In some cases, we remove a recommendation from the list if it becomes apparent that the cost of implementation would be significantly greater than originally anticipated, there is a material change in the underlying drivers for the recommendation, or there is little prospect for adoption.

Recommendations removed since the 2023 SOM Report

We have removed from this report the following recommendations that were made in the 2023 State of the Market Report:

2017-1: Model local reserve requirements in New York City load pockets. – This recommendation has been replaced with similar recommendation #2024-1, which applies to load pockets throughout the NYISO footprint.

2021-2: Model full reserve requirements for Long Island. – This recommendation has been replaced with similar recommendation #2024-1, which applies to load pockets throughout the NYISO footprint.

2012-13: Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment. – While NYISO has not made market reforms that would address our concerns with the inconsistent timing of key steps in RTC and RTD which currently lead to inefficient real-time scheduling and dispatch, we are reassessing how potential solutions contemplated in this recommendation would be best combined with efforts to integrate intermittent renewables and other non-conventional resources. We will continue to evaluate these issues in future reports.

Analytic Appendix

2024 State of the Market Report

For the

New York ISO Markets

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I. Market Prices and Outcomes

The New York ISO operates a multi-settlement wholesale market system consisting of financially binding day-ahead and real-time markets for energy, operating reserves, and regulation (i.e., automatic generation control). Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. Additionally, the NYISO operates markets for transmission congestion contracts and installed capacity, which are evaluated in Sections III and VI of the Appendix.

This section of the appendix summarizes the market results and performance in 2024 in the following areas:

- Wholesale market prices;
- Fuel prices and generation by fuel type;
- Fuel usage under tight gas supply conditions;
- Emissions from internal generators;
- Load levels;
- Day-ahead ancillary services prices;
- Price corrections;
- Day-ahead energy market performance; and
- Day-ahead ancillary services market performance.

A. Wholesale Market Prices

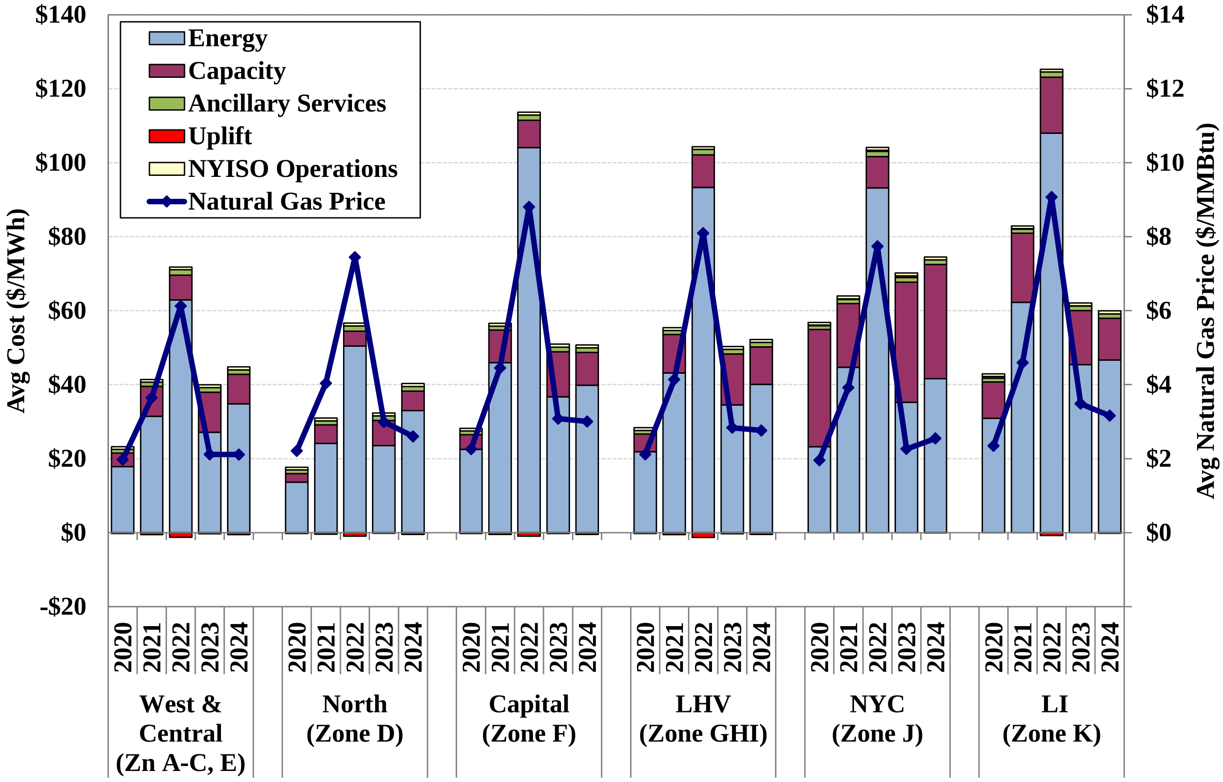
Figure A-1: Average All-In Price by Region

The first analysis displays the total costs of serving load from the NYISO markets as the all-in price for electricity. This value represents the sum of all wholesale market costs, including energy, uplift, capacity, ancillary services, and NYISO cost of operations. The all-in price is calculated for various locations in New York State, reflecting the substantial variability in capacity and energy prices by location. In this metric:

- **The energy component** is load-weighted average real-time energy prices.
- **The capacity component** is derived from clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over energy consumption in that area.
- **The uplift component** includes both local and statewide uplift costs from Schedule 1 charges, allocated over the energy consumed in the area.
- **Ancillary services costs** are distributed evenly across all locations for purposes of this metric.

Figure A-1 shows the average all-in prices along with the average natural gas prices from 2020 to 2024 at the following seven locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and (g) Long Island (i.e., Zone K). The majority of congestion in New York occurs between and within these regions.

Figure A-1: Average All-In Price by Region
2020 – 2024



Natural gas prices are based on the following gas indices (plus a transportation charge): (a) the Niagara index from December to March and Tennessee Zone 4 200L index during the rest of the year for the West Zone and Central New York; (b) the Iroquois Waddington index for the North Zone; (c) the minimum of Tennessee Zone 6 and Iroquois Zone 2 indices for the Capital Zone; (d) the average of Iroquois Zone 2 index and the TETCO M3 index for Lower Hudson Valley; (e) the Transco Zone 6 (NY) index for New York City, and (f) the Iroquois Zone 2 index for Long Island.[209] An incremental 6.9 percent tax rate is also reflected in the natural gas prices for New York City. An incremental 1 percent tax rate is reflected for Long Island.

Figure A-2: Day-Ahead Electricity and Natural Gas Costs

Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2024 for the seven locations shown in Figure A-2. The inset

209 The following transportation costs are included in the delivered prices for each region: (a) $0.27 per MMBtu for Zones A through I, (b) $0.20 per MMBtu for New York City, and (c) $0.25 per MMBtu for Long Island.

table shows the annual averages of natural gas costs and LBMPs for 2023 and 2024. Although hydro and nuclear generators produce much of the electricity used by New York consumers, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York.[210]

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2024

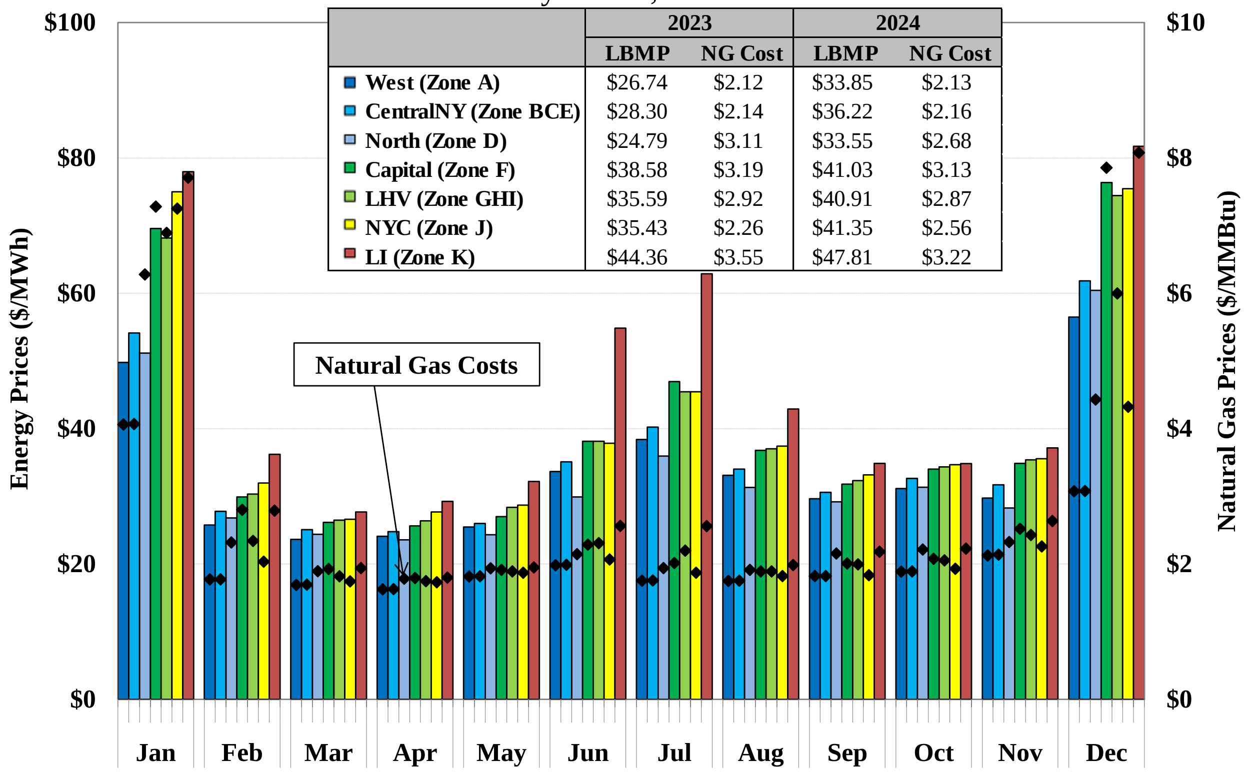


Figure A-3: Average Monthly Implied Marginal Heat Rate

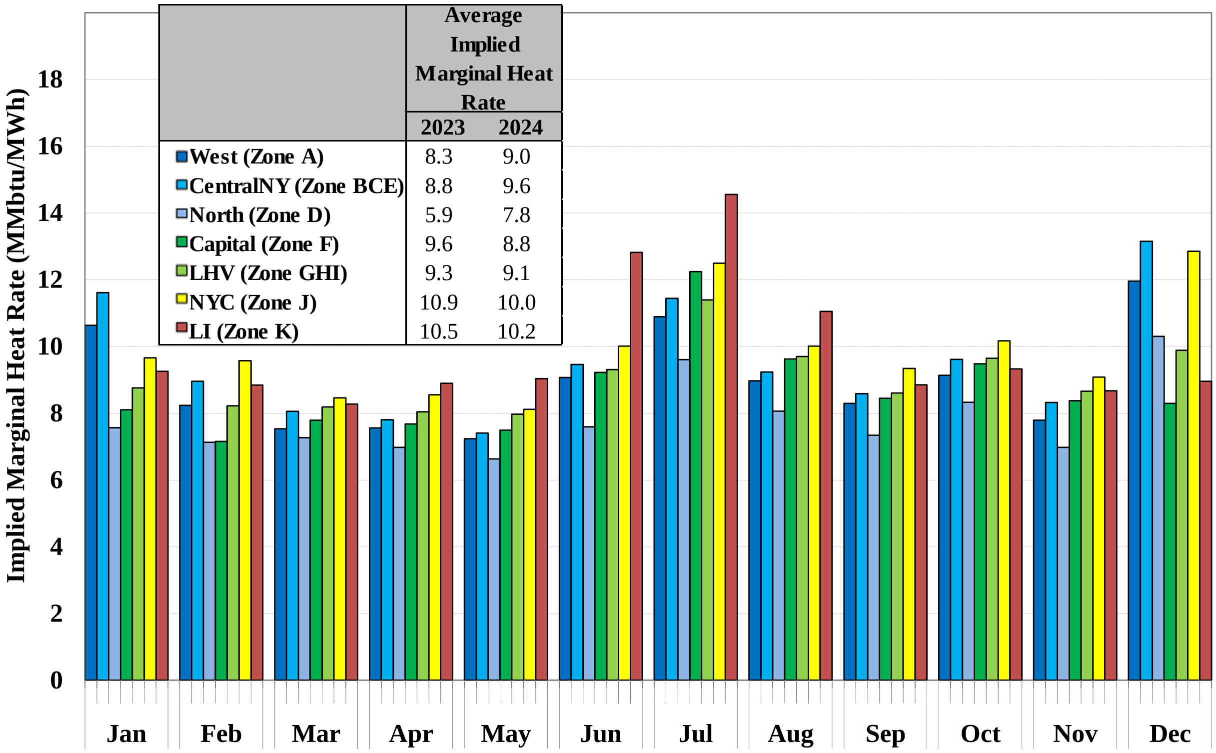
The following figure summarizes the monthly average implied marginal heat rate, which highlights changes in electricity prices that are not driven by fuel price fluctuations.

The *Implied Marginal Heat Rate* is calculated as the day-ahead electricity price minus a generic unit Variable Operations and Maintenance ("VOM") cost then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost). For example, if the electricity price is $40 per MWh, the VOM cost is $3 per MWh, the natural gas price is $3 per MMBtu, and the RGGI clearing price is $13 per CO_2 allowance, then, the implied marginal heat rate would indicate that a generator with a 9.8 MMBtu per MWh heat rate is on the margin.[211]

210 The prevalence of natural gas units as the marginal resource is apparent from the strong correlation between LBMPs and natural gas prices, particularly in Eastern New York.

211 In this example, the implied marginal heat rate is calculated as ($40/MWh – $3/MWh) / ($3/MMBtu + $13/ton * 0.06 ton/MMBtu emission rate), which equals 9.8 MMBtu per MWh.

Figure A-3: Average Monthly Implied Marginal Heat Rate
Day-Ahead Market, 2024



	Average Implied Marginal Heat Rate	
	2023	2024
West (Zone A)	8.3	9.0
CentralNY (Zone BCE)	8.8	9.6
North (Zone D)	5.9	7.8
Capital (Zone F)	9.6	8.8
LHV (Zone GHI)	9.3	9.1
NYC (Zone J)	10.9	10.0
LI (Zone K)	10.5	10.2

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2024 for the seven locations shown in Figure A-1 and Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2023 and in 2024 at these locations. By adjusting for variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours and locations. Figure A-4 shows seven price duration curves for 2024, one for each of the following locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and (g) Long Island (i.e., Zone K). Each curve in Figure A-4 shows the number of hours (horizontal axis) when the load-weighted average real-time price in each region exceeded the corresponding price level (vertical axis). Additionally, the table in the chart shows the number of hours in 2024 at each location when the real-time price exceeded $100, $200, and $500 per MWh.

The price duration curves show the distribution of prices in wholesale electricity markets, where a small number of hours exhibited very high prices that are typically associated with shortages.

Prices during shortages may rise to more than ten times the annual average price level, meaning that even a limited number of price spikes can significantly impact the average price level.[212]

Figure A-4: Real-Time Price Duration Curves by Region
2024

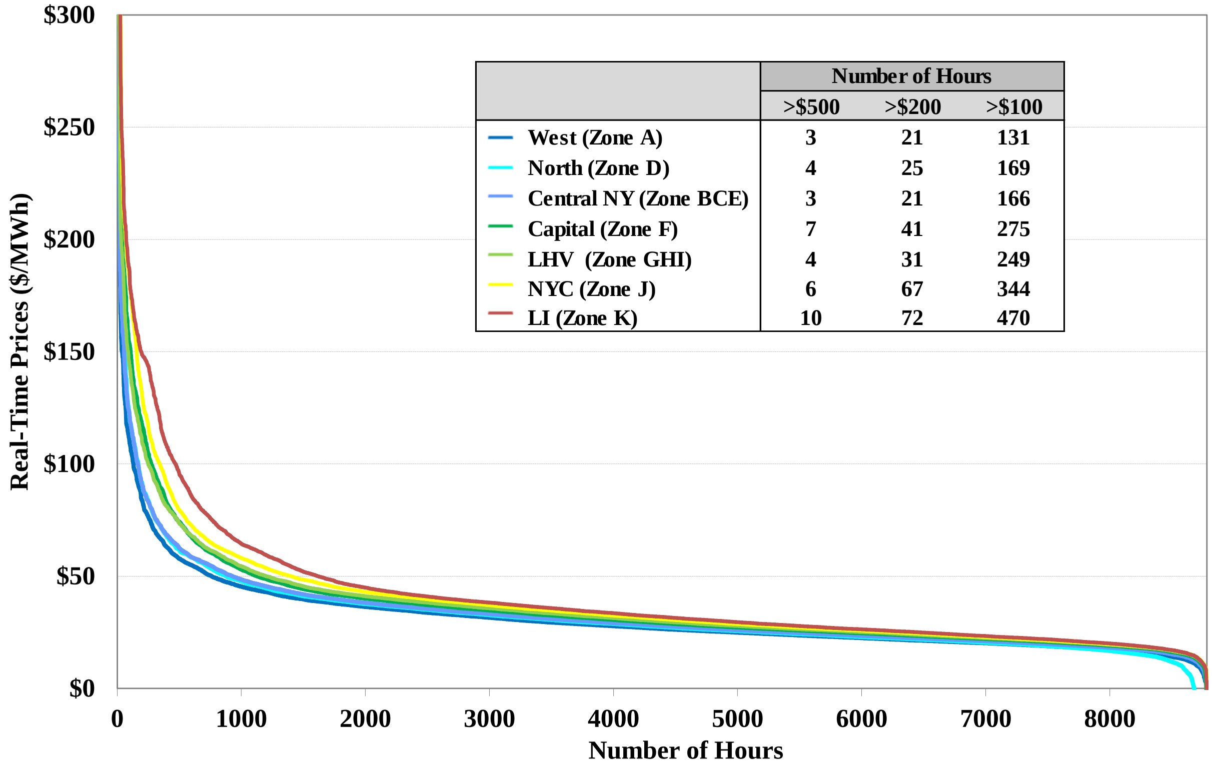


Figure A-5 shows the implied marginal heat rate duration curves for each location from the previous chart during 2024. Each curve shows the number of hours (horizontal axis) when the implied marginal heat rate for each sub-region exceeded the corresponding level (vertical axis). The calculation of the implied marginal heat rate follows the same methodology as in Figure A-3 except that this is based on real-time prices rather than day-ahead prices. The inset table compares the number of hours in each region when the implied heat rate exceeded 8 and 11 MMBtu per MWh between 2023 and 2024.

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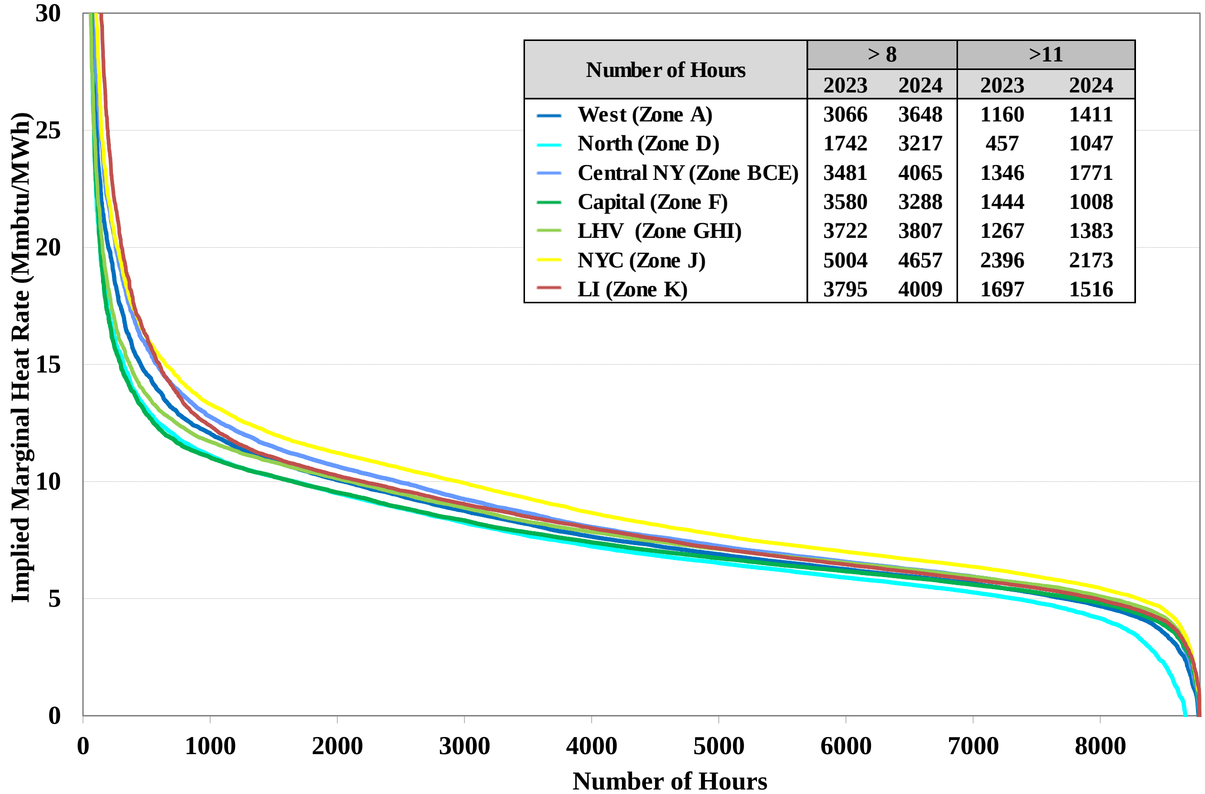
212 In other words, the distribution of energy prices across the year is "right skewed", meaning that the average price is greater than the median price due to the impact of shortage pricing hours.

Figure A-5: Implied Heat Rate Duration Curves by Region
2024



Number of Hours	> 8		>11	
	2023	2024	2023	2024
West (Zone A)	3066	3648	1160	1411
North (Zone D)	1742	3217	457	1047
Central NY (Zone BCE)	3481	4065	1346	1771
Capital (Zone F)	3580	3288	1444	1008
LHV (Zone GHI)	3722	3807	1267	1383
NYC (Zone J)	5004	4657	2396	2173
LI (Zone K)	3795	4009	1697	1516

B. Fuel Prices and Generation by Fuel Type

Figure A-6 to Figure A-9: Fuel Prices, RGGI Costs, and Generation by Fuel Type

Fluctuations in fossil fuel prices, especially natural gas prices, have been the primary driver of changes in wholesale electricity prices over the past several years.[213] This is because fuel costs account for most of the marginal production costs of fossil fuel generators.

Some generators in New York have dual-fuel capability, allowing them to burn either oil or natural gas. These generators usually burn the most economic fuel, which often translates to using natural gas as the default choice for most of the year. Situations may arise, however, where some generators opt to burn oil even if it is more expensive, due to specific circumstances or operational considerations.[214] Since most large steam units can burn either oil or natural gas,

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213 Although much of the electricity generated in New York is from hydroelectric and nuclear generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices more directly affect wholesale electricity prices.

214 For instance, natural gas may be difficult to obtain on short notice. In addition, New York City and Long Island reliability rules sometimes require that certain units burn oil to limit the exposure of the electric grid to possible disruptions in the supply of natural gas.

the effects of natural gas price spikes on electricity prices during periods of high volatility are partly mitigated by generators switching to oil.[215]

Natural gas price patterns are normally consistent between different regions in New York, with eastern regions typically having a small premium in price compared to the western zones. However, bottlenecks on the natural gas system can lead to significant differences in delivered gas costs by area, particularly during peak winter conditions. This in turn can produce comparable differences in energy prices when network congestion occurs. The natural gas price differences generally emerge by pipeline and by zone. We track natural gas prices for the following pipelines/zones, which serve different areas in New York.

- Tennessee Zone 6 prices are representative of natural gas prices in the Capital Zone as well as in portions of New England;
- Transco Zone 6 (NY) prices are representative of natural gas prices in New York City;
- Iroquois Zone 2 prices are representative of natural gas prices in the Capital Zone and Long Island;
- TETCO M3 prices and Iroquois Zone 2 are representative of natural gas prices in various locations of the Lower Hudson Valley region; and
- Tennessee Zone 4 200L prices are representative of natural gas prices in portions of Western New York.

Figure A-6 shows average natural gas and fuel oil prices by month from 2021 to 2024. The table compares the annual average fuel prices for these four years. [216]

Reginal Greenhouse Gas Initiative (RGGI) allowance prices have increased substantially over the past few years, contributing significantly to the costs of electricity production in 2024. In Figure A-7, the upper portion shows monthly RGGI allowance prices 2019 to 2024, while the lower portion illustrates the equivalent energy costs, expressed in $ per MWh, for hypothetical generating units with heat rates of 7,500 Btu/kWh and 10,000 Btu/kWh, respectively.[217]

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2024 as well as for all the NYCA.[218] The table in the chart shows annual average generation by fuel type from 2022 to 2024.

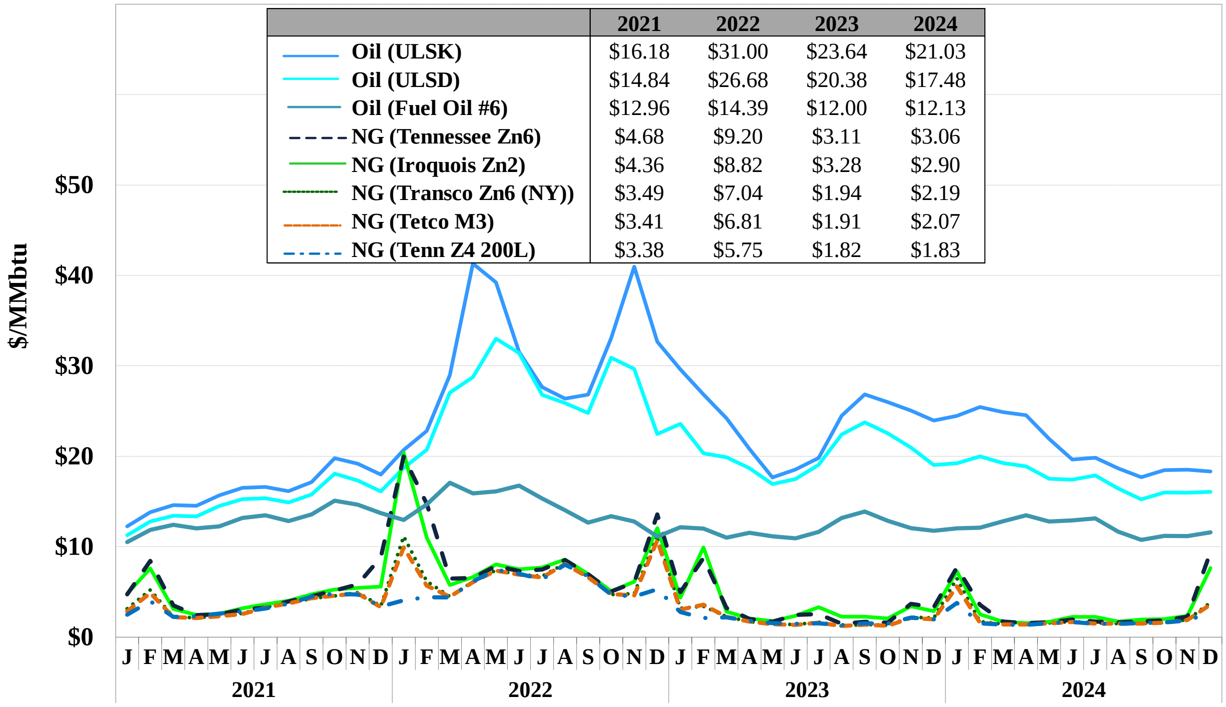
215 Conventional steam units that have dual-fuel capability are required to burn No. 2 oil (ULSD) in New York City, but they generally burn No. 6 residual fuel oil in other areas.

216 These are index prices that do not include transportation charges or applicable local taxes.

217 The equivalent energy cost equals RGGI price * 0.06 short ton/MMBtu * unit heat rate.

218 Pumped-storage resources in pumping mode are treated as negative generation. The “Other” category includes methane, refuse, solar, and wood.

Figure A-6: Monthly Average Fuel Index Prices
2021 – 2024



	2021	2022	2023	2024
Oil (ULSK)	$16.18	$31.00	$23.64	$21.03
Oil (ULSD)	$14.84	$26.68	$20.38	$17.48
Oil (Fuel Oil #6)	$12.96	$14.39	$12.00	$12.13
NG (Tennessee Zn6)	$4.68	$9.20	$3.11	$3.06
NG (Iroquois Zn2)	$4.36	$8.82	$3.28	$2.90
NG (Transco Zn6 (NY))	$3.49	$7.04	$1.94	$2.19
NG (Tetco M3)	$3.41	$6.81	$1.91	$2.07
NG (Tenn Z4 200L)	$3.38	$5.75	$1.82	$1.83

Figure A-7: RGGI Allowances Prices and Equivalent Energy Cost
By Month, 2019-2024

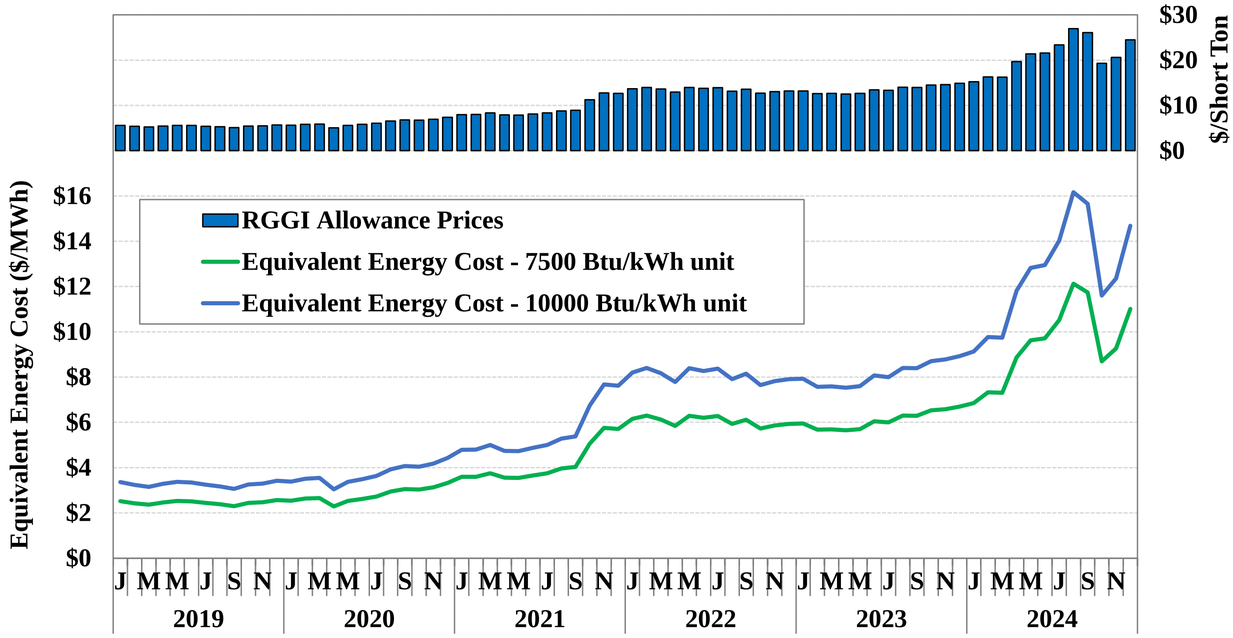
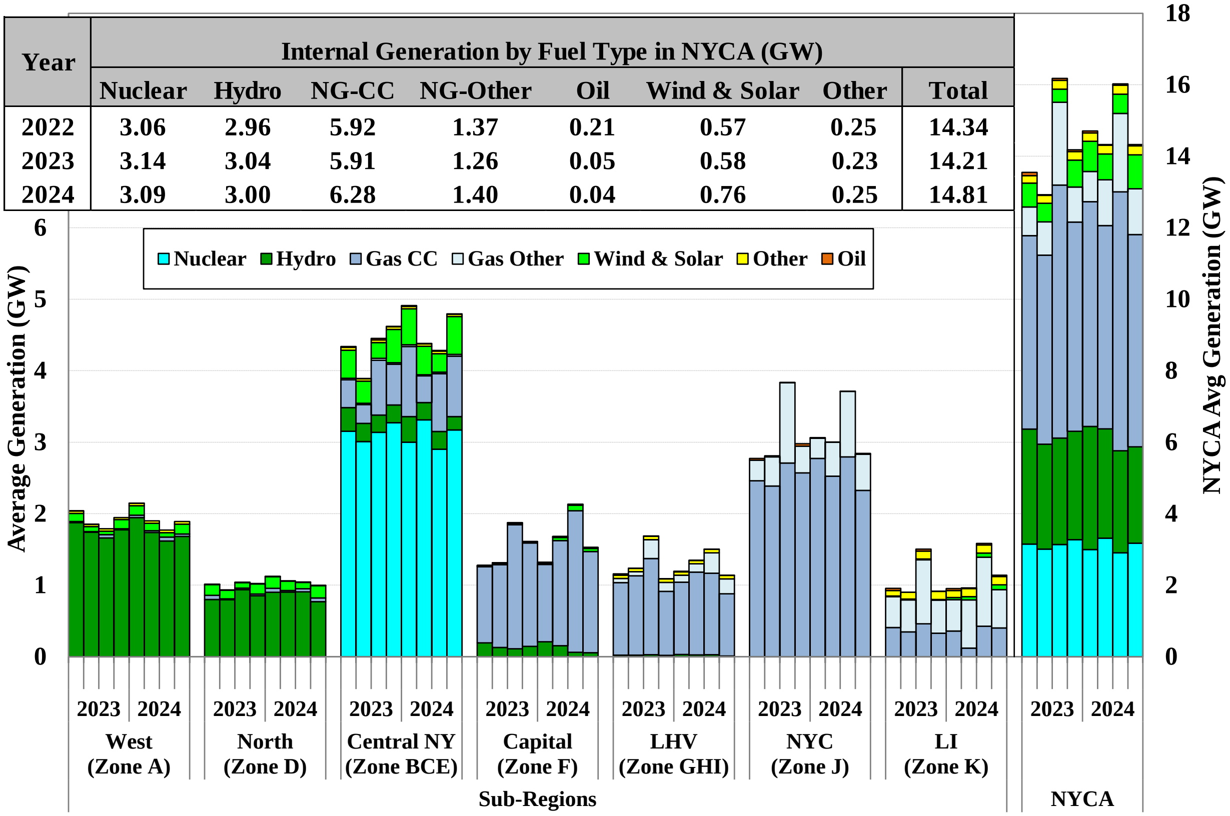


Figure A-8: Generation by Fuel Type in New York
By Quarter by Region, 2024

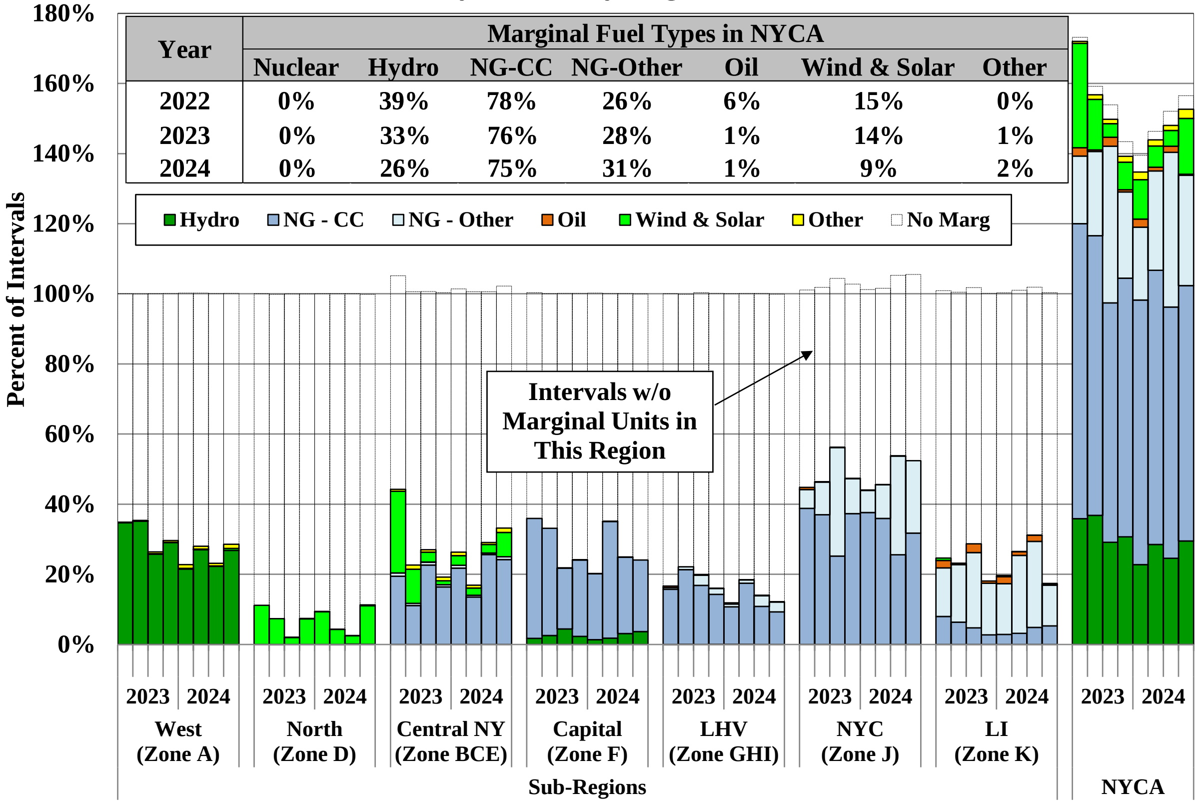


Year	Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind & Solar	Other	Total
2022	3.06	2.96	5.92	1.37	0.21	0.57	0.25	14.34
2023	3.14	3.04	5.91	1.26	0.05	0.58	0.23	14.21
2024	3.09	3.00	6.28	1.40	0.04	0.76	0.25	14.81

Figure A-9 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2024. The table in the chart shows annual statistics by fuel type from 2022 to 2024. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may be marginal in the constrained and unconstrained areas). Hence, the total for all fuel types may be greater than 100 percent. For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent. When no unit is on the margin in a particular region, the LBMPs in that region are set by: (a) generators in other regions in most intervals; or (b) shortage pricing of ancillary services or transmission constraints in a small share of intervals.

The fuel type for each generator in both Figure A-7 and Figure A-9 is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").

Figure A-9: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2024



C. Fuel Usage Under Tight Gas Supply Conditions

The supply of natural gas is usually tight in the winter season due to increased demand for heating. Extreme weather conditions often lead to high and volatile natural gas prices. A large share of generators in Eastern New York has dual-fuel capability, allowing them to switch to an alternative fuel when natural gas becomes expensive or unavailable. However, the increase in oil-fired generation during such periods may be limited by several factors, including:

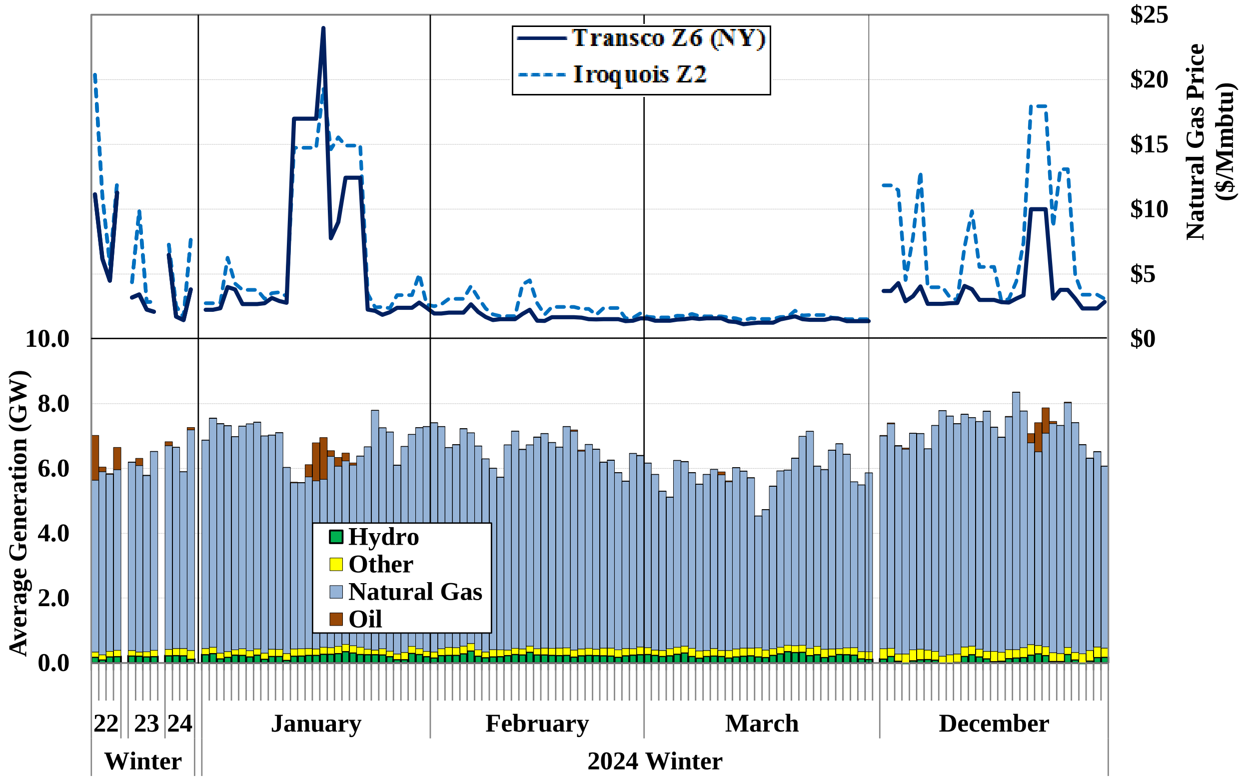
- Not having the necessary air permits;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and
- NOx emissions limitations.

This subsection examines actual fuel usage in the winter of 2024, focusing on the portion of the year where the supply of natural gas is likely to be tight. This has historically had a big impact on the system operations, especially in Eastern New York.

Figure A-10: Actual Fuel Use and Natural Gas Prices in the Winter

Figure A-10 summarizes the average hourly generation by fuel consumed in Eastern New York daily during the winter months of 2024 (including the months of January, February, March, and December).

Figure A-10: Actual Fuel Use and Natural Gas Prices
Eastern New York, Winter Months, 2024



The figure shows actual generation for the following fuel categories: (a) oil; (b) natural gas; (c) hydro; (d) nuclear; and (e) all other fuel types as a group. In addition, the figure shows the day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY). The figure also compares these quantities by month for the same four-month period between 2022 and 2024. Each day in the chart represents a 24-hour gas day, which starts from 10 am on each calendar day and ends at 10 am on the next calendar day.

D. Emissions from Internal Generation

Power plants generate three main air pollutants when generating electricity: sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). These emissions from electricity generation vary by type of fuel, energy technology, and power plant efficiency and have declined substantially since the inception of the NYISO markets. Policy makers have set up aggressive agenda in recent years for an ambitious clean energy transition from conventional energy resources. It is important for the NYISO markets to provide strong and clear incentives to attract new technologies and help integrate clean energy resources. This subsection examines the emission levels of the three major pollutants from internal generation resources in the NYISO markets.

Figure A-11: Historical Emissions by Quarter in NYCA

Figure A-11 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_x, and SO_2 by quarter.

Figure A-11: Historical Emissions of CO_2, NO_x, and SO_2 in NYCA
By quarter, 2000-2024

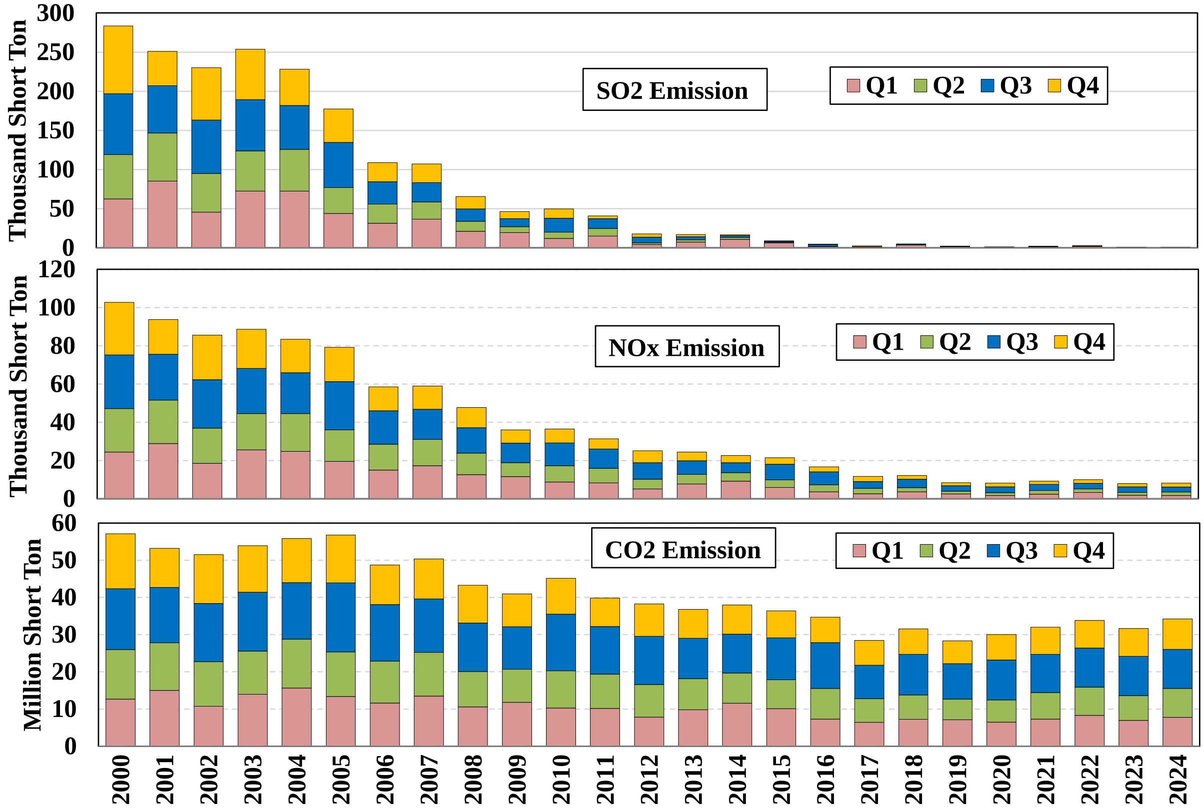
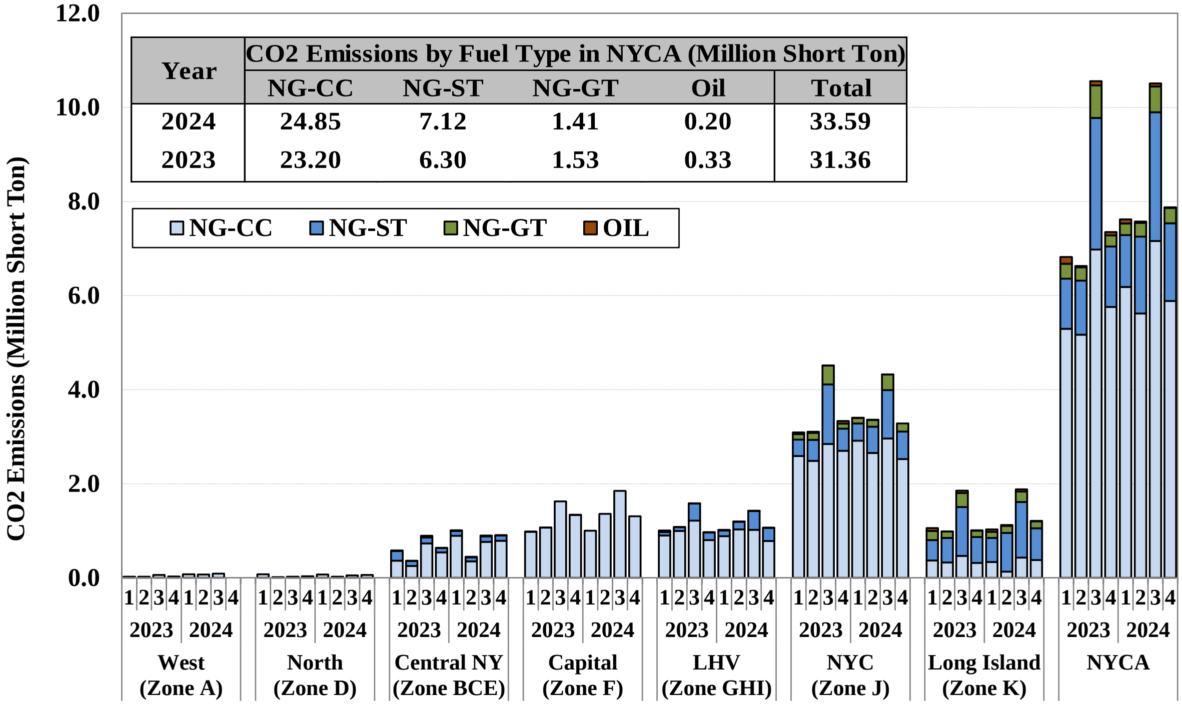


Figure A-12 - Figure A-13: Emissions by Region by Fuel Type

The following two figures show quarterly emissions across the system by generation fuel type for CO_2, and NOx, respectively. Emission values are given for seven regions as well as the system as a whole for 2023 and 2024. The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter. The inset table in each chart provides summary data on the total tonnage of emissions by fuel type.

Figure A-12: CO_2 Emissions by Region by Fuel Type

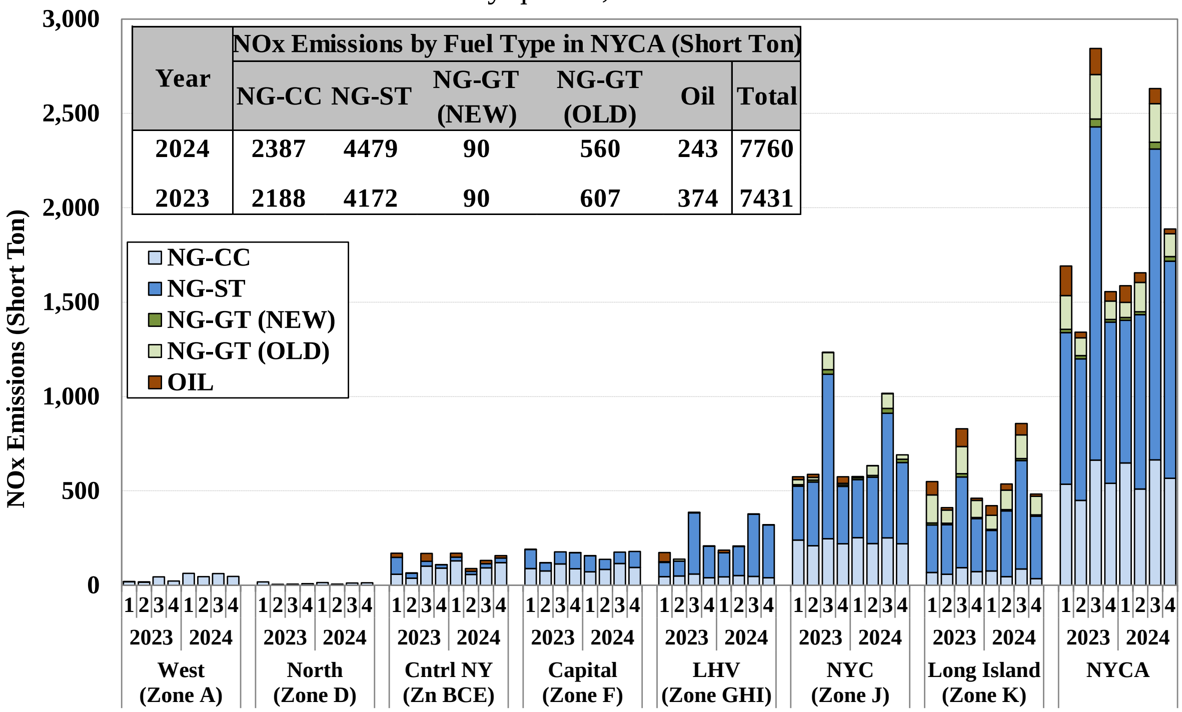
by quarter, 2023-2024



Year	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)				
	NG-CC	NG-ST	NG-GT	Oil	Total
2024	24.85	7.12	1.41	0.20	33.59
2023	23.20	6.30	1.53	0.33	31.36

Figure A-13: NOx Emissions by Region by Fuel Type

by quarter, 2023-2024



Year	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2024	2387	4479	90	560	243	7760
2023	2188	4172	90	607	374	7431

E. Load Levels

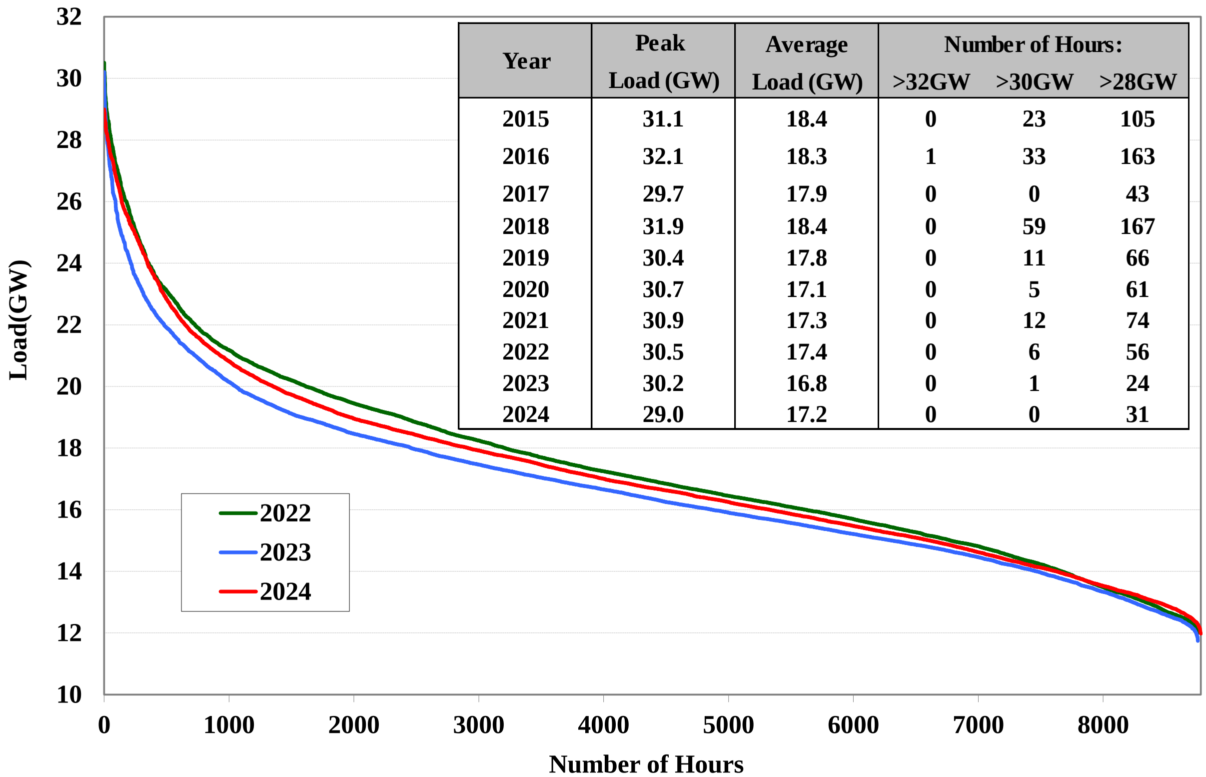
Figure A-14: Load Duration Curves for New York State

The interaction between electric supply and consumer demand is another key driver of price movements in New York. Since year-to-year changes in supply are usually small, fluctuations in electricity demand explain much of the short-term variations in electricity prices. The highest-load hours are particularly important, as they account for a disproportionately large share of both market costs to consumers and revenues to generators.

Figure A-14 presents load duration curves that illustrate demand variation over the past three years. These curves show the number of hours (horizontal axis) in which the statewide load was greater than or equal to the corresponding level (vertical axis). Additionally, the inset table provides the annual average load levels for the past ten years and the number of hours in each year when the system load exceeded 28, 30, and 32 GW.

Figure A-14: Load Duration Curves for New York State

2022 – 2024



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2015	31.1	18.4	0	23	105
2016	32.1	18.3	1	33	163
2017	29.7	17.9	0	0	43
2018	31.9	18.4	0	59	167
2019	30.4	17.8	0	11	66
2020	30.7	17.1	0	5	61
2021	30.9	17.3	0	12	74
2022	30.5	17.4	0	6	56
2023	30.2	16.8	0	1	24
2024	29.0	17.2	0	0	31

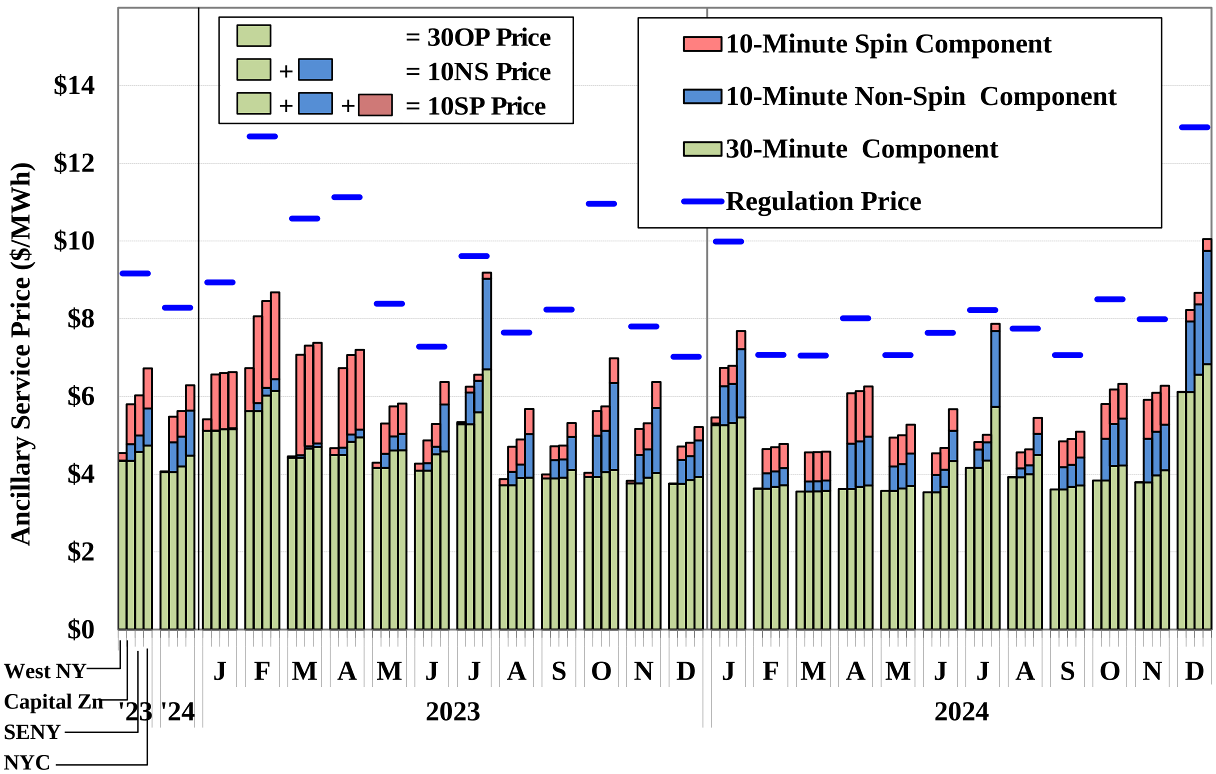
F. Day-Ahead Ancillary Services Prices

Figure A-15: Day-Ahead Ancillary Services Prices

The NYISO schedules resources to provide energy, operating reserves, and regulation service in the day-ahead and real-time markets. The NYISO co-optimizes the scheduling of these products such that the combined cost of all products is minimized. Given that available supplies must satisfy energy demand and ancillary services requirements simultaneously, energy and ancillary services prices both reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. Hence, ancillary services prices generally rise and fall with the price of energy because it influences the level of these opportunity costs.

NYISO has four market-based ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation. In addition, the NYISO has locational reserve requirements that result in differences between Western, Eastern, Southeast New York and New York City reserve prices. The figure shows the average day-ahead prices for these four ancillary services products in each month of 2023 and 2024. The prices are shown separately for the following four distinct regions: (a) New York City, (b) Southeast New York (including Zones G-I and Zone K); (b) the Capital Zone (Zone F, in Eastern New York but outside Southeast New York); and (c) West New York (including Zones A-E).

Figure A-15: Day-Ahead Ancillary Services Prices
2023 - 2024



The stacked bars show three price components for each region: the 10-minute spinning component, the 10-minute non-spin component, and the 30-minute component, each representing the cost of meeting applicable reserve requirements. Take New York City as an example:

- The 30-minute component represents the cost to simultaneously meet the 30-minute reserve requirements for New York City, Southeast New York, East New York, and NYCA;

- The 10-minute non-spin component represents the cost to simultaneously meet the 10-minute total reserve requirements for New York City, East New York and NYCA (Southeast New York does not have a separate 10-minute total reserve requirement); and
- The 10-minute spinning component represents the cost to simultaneously meet the 10-minute spinning reserve requirements for East New York and NYCA (New York City and Southeast New York do not have separate 10-minute spinning reserve requirements).

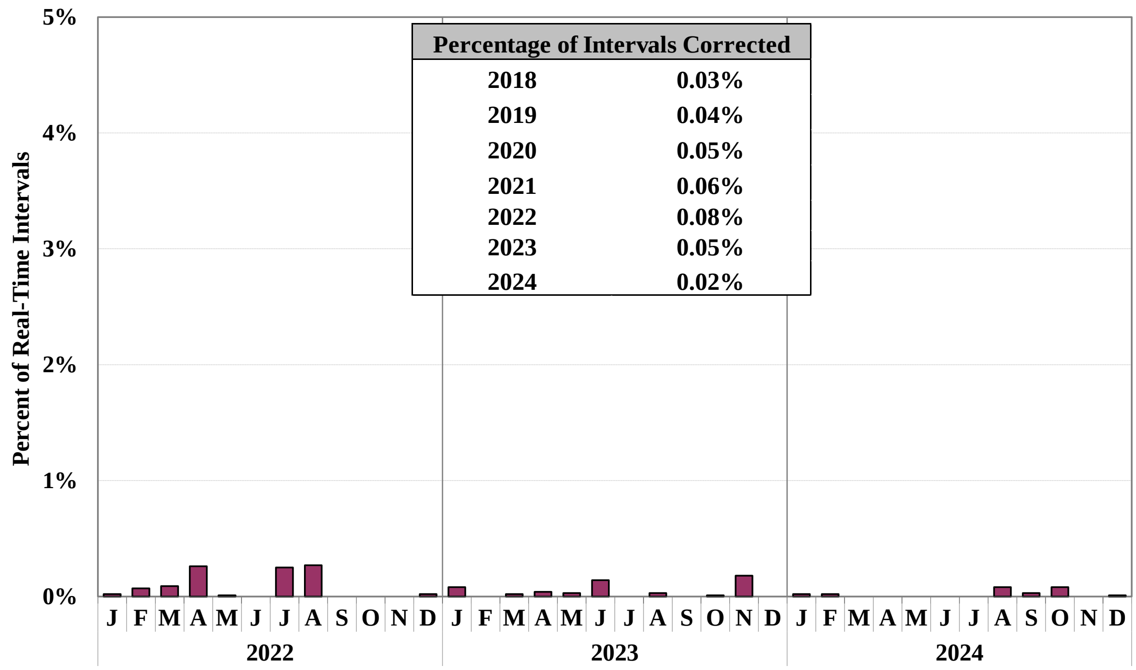
Therefore, in the figure, the 30-minute reserve price in each region equals its 30-minute component, the 10-minute non-spin reserve price equals the sum of its 30-minute component and 10-minute non-spin component, and the 10-minute spinning reserve price equals the sum of all three price components. The blue dashes give the day-ahead regulation capacity prices for the system. Finally, the inset table compares average final prices (not the components) in 2023 and 2024 on an annual basis.

G. Price Corrections

Figure A-16: Frequency of Real-Time Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors and other data input problems. Moreover, price corrections are required when flaws in the market operations software or operating procedures lead prices to be calculated erroneously. Accurate prices are critical for settling market transactions fairly and sending reliable real-time price signals. Less frequent corrections reduce administrative burdens and uncertainty for market participants. Hence, it is important to resolve problems that lead to price corrections quickly to maximize price certainty.

Figure A-16: Frequency of Real-Time Price Corrections
2022 - 2024



The figure summarizes the frequency of price corrections in the real-time energy market in each month from 2022 to 2024. The table in the figure indicates the change in the frequency of price corrections over the past several years. Price corrections continue to be very infrequent.

H. Day-Ahead Energy Market Performance

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real-time. Participants can use the day-ahead market to hedge risks associated with the real-time market, and the system operator uses day-ahead bids and offers to improve the commitment of resources. Similarly, loads can insure against price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of starting-up their generators on an unprofitable day since the day-ahead auction market will only accept their offers when commitments are profitable. In addition to the value it provides individual market participants, perhaps the greatest value of the day-ahead market is that it coordinates the overall commitment of resources to satisfy the next day's needs at least cost.

In a well-functioning system with day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge from one another. If day-ahead prices were predictably higher than real-time prices, buyers would increase purchases in real-time. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers would increase purchases day-ahead (vice versa for sellers).

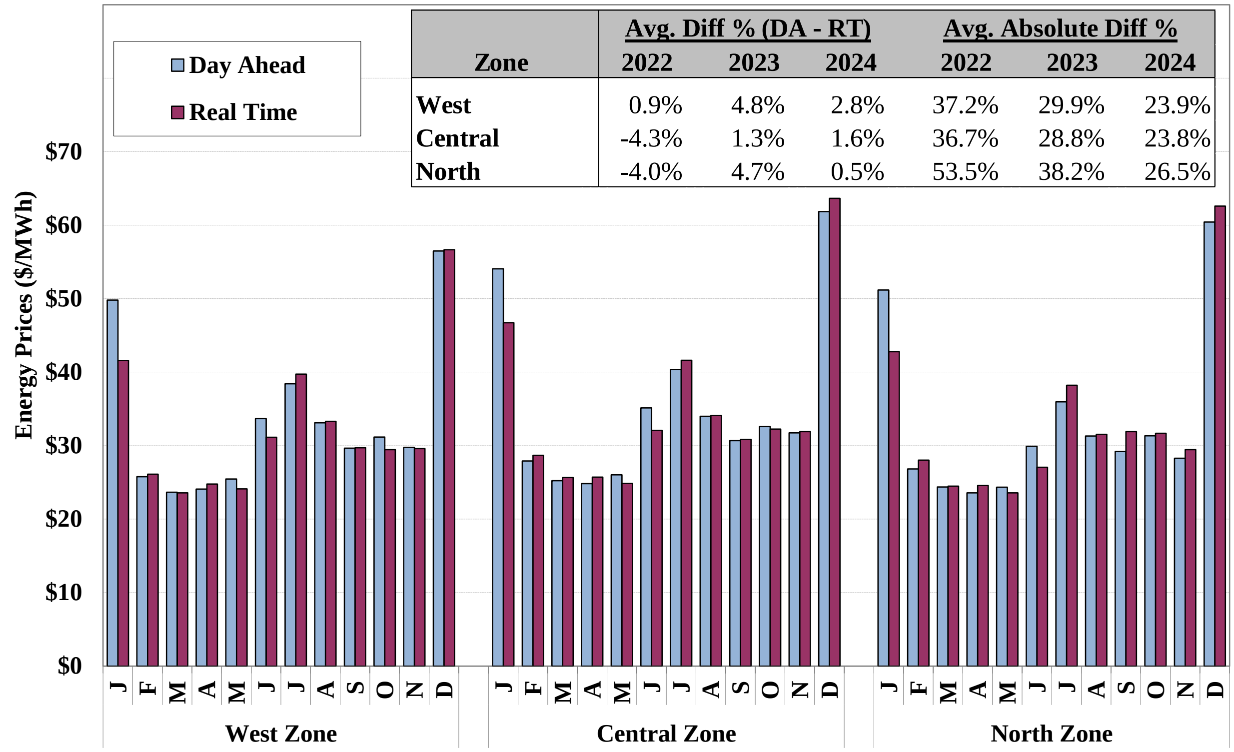
Price convergence is desirable because it promotes efficient commitment of generating resources, procurement of fuel, and scheduling of external transactions. Persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer at marginal cost in the day-ahead market. We expect random variations from unanticipated changes in supply and demand between the two markets on an hour-to-hour basis, but persistent systematic differences between day-ahead and real-time prices would raise potential concerns.

Figure A-17 & Figure A-18: Average Day-Ahead and Real-Time Energy Prices

In general, day-ahead prices are based on the expectations of real-time market outcomes and are influenced by several uncertainties. First, demand can be difficult to forecast with precision and the availability of supply may change due to forced outages or numerous other factors. For example, the operators may commit additional generation for reliability after the day-ahead market, increasing the supply available to the real-time market. Second, special operating conditions, such as thunderstorm alerts, may alter the capability of the transmission system in ways that are difficult to arbitrage in day-ahead markets. Accordingly, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

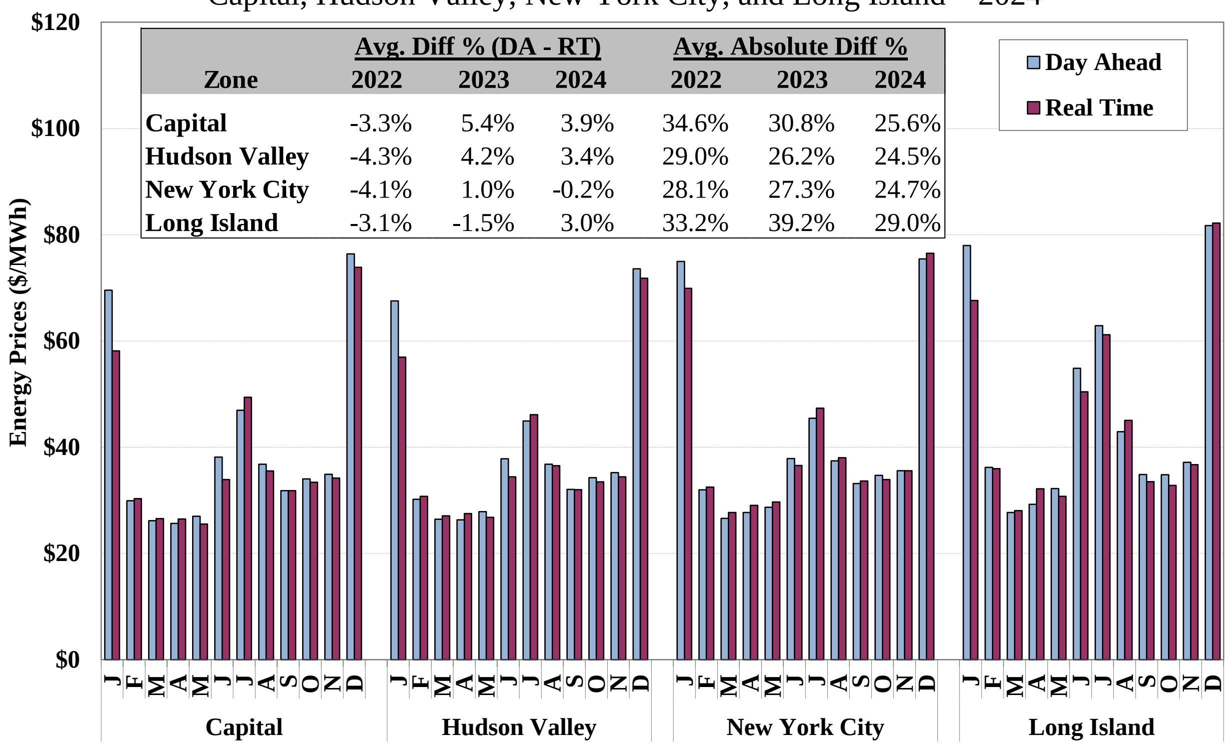
Figure A-17 and Figure A-18 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island.

Figure A-17: Average Day-Ahead and Real-Time Energy Prices in Western New York
West, Central, and North Zones – 2024



Zone	Avg. Diff % (DA - RT) 2022	2023	2024	Avg. Absolute Diff % 2022	2023	2024
West	0.9%	4.8%	2.8%	37.2%	29.9%	23.9%
Central	-4.3%	1.3%	1.6%	36.7%	28.8%	23.8%
North	-4.0%	4.7%	0.5%	53.5%	38.2%	26.5%

Figure A-18: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2024



Zone	Avg. Diff % (DA - RT) 2022	2023	2024	Avg. Absolute Diff % 2022	2023	2024
Capital	-3.3%	5.4%	3.9%	34.6%	30.8%	25.6%
Hudson Valley	-4.3%	4.2%	3.4%	29.0%	26.2%	24.5%
New York City	-4.1%	1.0%	-0.2%	28.1%	27.3%	24.7%
Long Island	-3.1%	-1.5%	3.0%	33.2%	39.2%	29.0%

The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars show average monthly day-ahead and real-time prices weighted on the hourly day-ahead load in each zone. The inset tables report the percentage difference between the average day-ahead price and the average real-time price, as well as the average absolute value of the difference between hourly day-ahead and real-time prices in the past three years. The latter metric measures the typical difference between the day-ahead and real-time prices in each hour, regardless of which is higher. This metric is substantially affected by real-time price volatility.

Transmission congestion can lead to a wide variation in nodal prices within a zone, while the price of each zone is a load-weighted average of the nodal prices in the zone. Hence, the pattern of intrazonal congestion may differ between the day-ahead market and the real-time market, leading to poor convergence at individual nodes even though convergence is good at the zonal level.

The pattern of intrazonal congestion may change between the day-ahead market and the real-time market for many reasons:

- Generators may change their offers after the day-ahead market. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead.
- Generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows.
- Constraint limits used to manage congestion may change from the day-ahead market to the real-time market.
- Transmission constraints that are sensitive to the level of demand may become more or less acute after the day-ahead market due to differences between expected load and actual load.
- Transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit either virtual trades or price sensitive load bids at the load pocket level or a more disaggregated level. Thus, good convergence at the zonal level may mask a significant lack of convergence within the zone.

I. Day-Ahead Reserve Market Performance

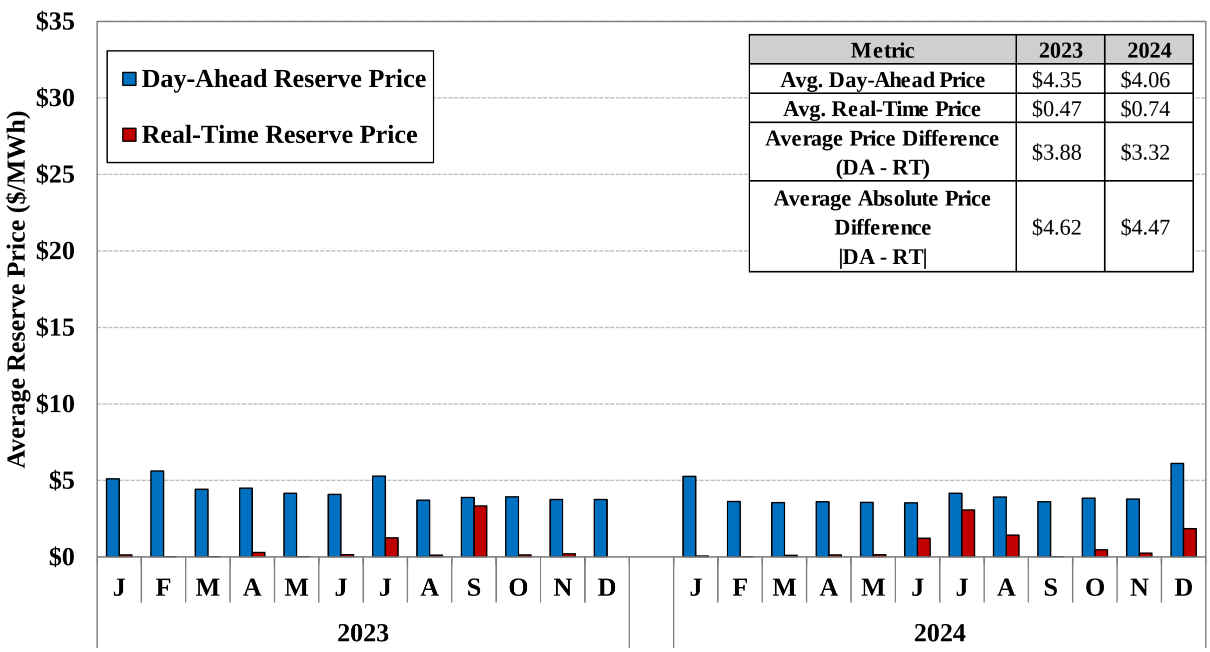
The NYISO co-optimizes the scheduling of energy, operating reserves, and regulation service such that the combined production cost of all products is minimized in the day-ahead and real-time markets. The energy and ancillary services markets place demand on the same supply resources, so prices for energy and ancillary services are highly correlated, and scarcity in the energy market is generally accompanied by a scarcity of ancillary services. As in the day-ahead energy market, a well-performing day-ahead ancillary service market will produce prices that converge well with real-time market prices.

In the market for energy, virtual trading improves convergence between day-ahead and real-time prices, which helps the ISO commit an efficient quantity of resources in the day-ahead market. In the ancillary services markets, on the other hand, only ancillary services suppliers directly participate and no virtual trading of ancillary services is allowed. Procurement of ancillary services is managed by the ISO, which obtains the same amounts of ancillary services in the day-ahead and real-time markets based on reliability criteria and without regard to price. Therefore, when systematic differences arise between day-ahead and real-time ancillary services prices, ancillary services suppliers are the only entities able to arbitrage them and improve convergence.

Figure A-19 to Figure A-21: Distribution of day-ahead price premiums for reserves

To evaluate the performance of the day-ahead ancillary service markets, the following three figures show the monthly day-ahead and real-time average prices for: (a) Western 30-minute reserve prices; (b) Eastern 10-minute spinning reserve prices; and (c) Eastern 10-minute non-spin reserve prices. These prices are shown for each month of the past two years. The inset table for each chart shows the annual averages for each year of: (a) the average day-ahead price; (b) the average real-time price; (c) the difference between the average day-ahead price and the average real-time price; and (d) the average absolute difference between the day-ahead price and the real-time price. Average absolute difference between the two prices provides a better metric for how consistent the convergence between day-ahead and real-time prices are than the simple average.

Figure A-19: Day-Ahead Premiums for 30-Minute Reserves in West New York
2023 – 2024



Metric	2023	2024
Avg. Day-Ahead Price	$4.35	$4.06
Avg. Real-Time Price	$0.47	$0.74
Average Price Difference (DA - RT)	$3.88	$3.32
Average Absolute Price Difference |DA - RT|	$4.62	$4.47

Figure A-20: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2023 – 2024

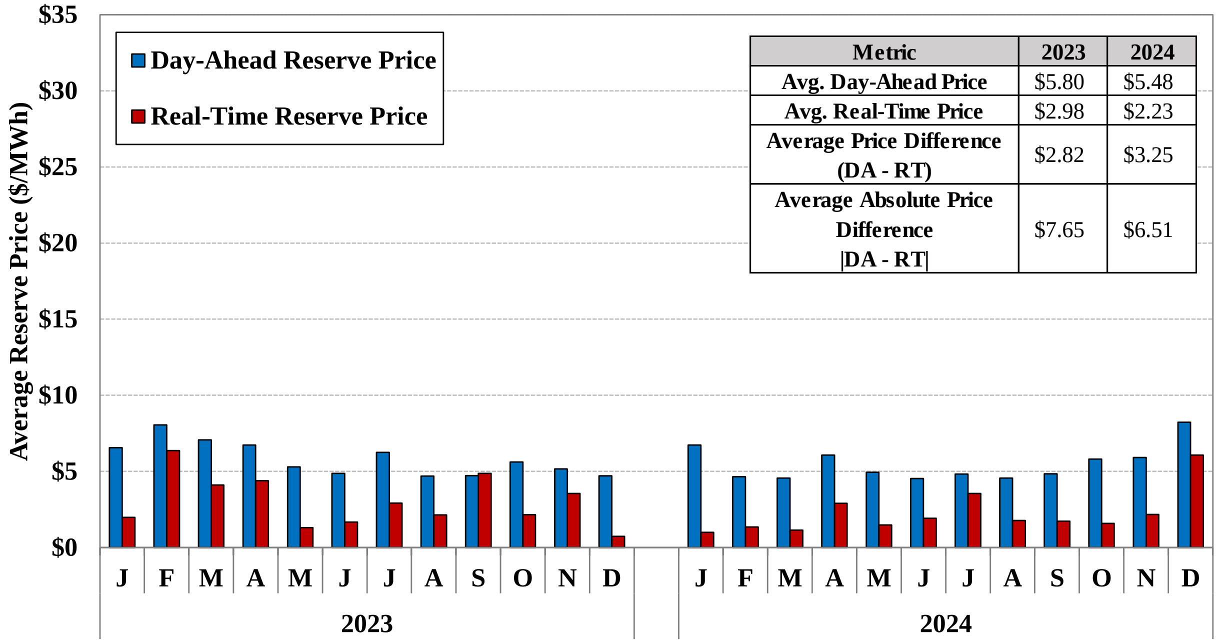
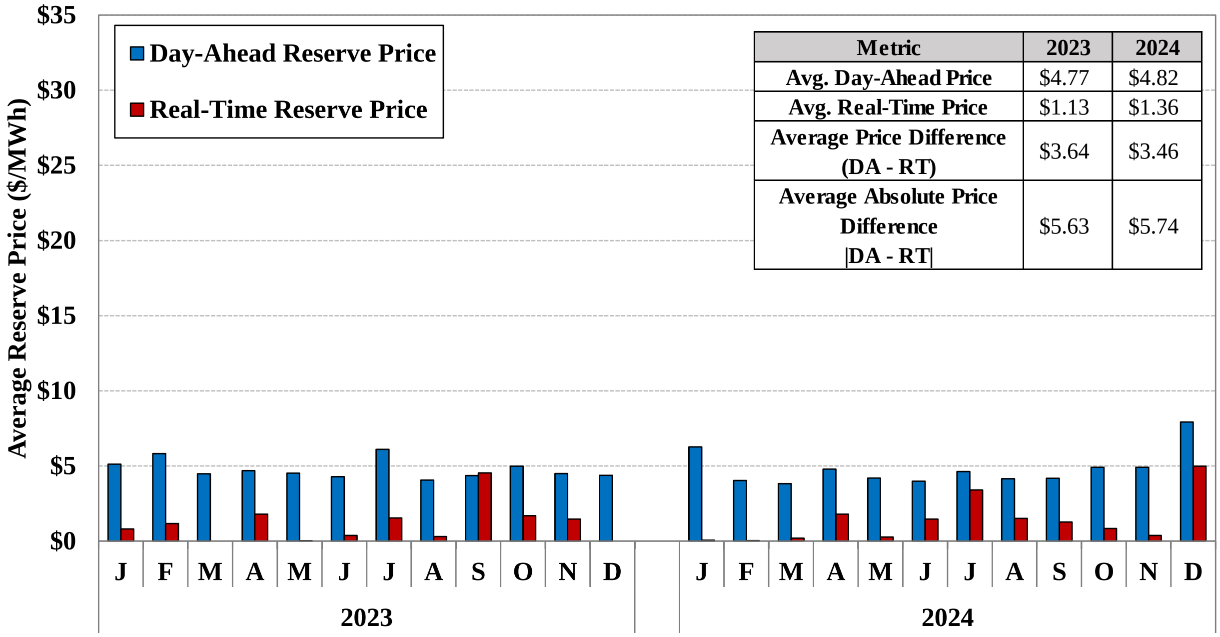


Figure A-21: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2023 – 2024



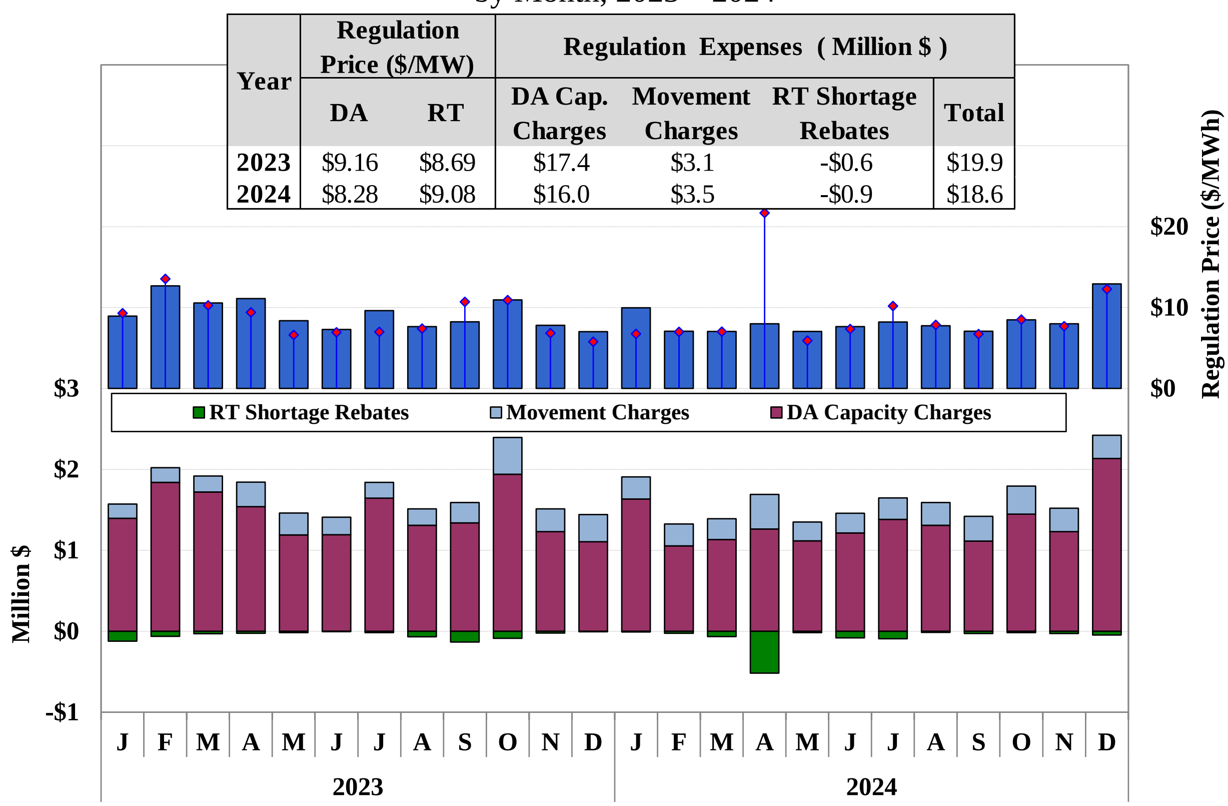
J. Regulation Market Performance

Figure A-22: Regulation Prices and Expenses

Figure A-22 shows the regulation prices and expenses in each month of the past two years. The upper portion of the figure compares the regulation prices in the day-ahead and real-time markets.[219] The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.
- Real-Time Shortage Rebate – This arises when a regulation shortage occurs in the real-time market and regulation suppliers have to buy back the shortage quantity at the real-time prices.
- Movement Charge – This is the compensation to regulation resources for dispatching up and down to provide regulation service. The payment amount equals the product of: (i) the real-time regulation movement price; (ii) the instructed regulation movement; and (iii) the performance factor calculated for the regulation service provider.

Figure A-22: Regulation Prices and Expenses
by Month, 2023 – 2024



Year	Regulation Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2023	$9.16	$8.69	$17.4	$3.1	-$0.6	$19.9
2024	$8.28	$9.08	$16.0	$3.5	-$0.9	$18.6

[219] The day-ahead and real-time regulation prices shown in the upper portion of the chart represent the composite value of the capacity price and a movement component.

II. Analysis of Energy and Ancillary Services Bids and Offers

In this section, we analyze energy and ancillary services bid and offer patterns to assess market efficiency and ensure that market participant conduct aligns with effective competition. Specifically, this section evaluates the following areas:

- Potential physical withholding;
- Potential economic withholding;
- Market power mitigation;
- Operating reserves offers in the day-ahead market;
- Load-bidding patterns; and
- Virtual trading behavior.

Suppliers with market power can exercise it in electricity markets by withholding resources to increase the market clearing price. Physical withholding occurs when a resource is derated or not offered into the market despite being economic to produce energy (i.e., when the market clearing price exceeds the resource's marginal cost). Suppliers may also physically withhold by providing inaccurate operating characteristics, such as excessively long start-up notification times. Economic withholding occurs when a supplier raises its offer price to reduce its output below competitive levels or otherwise increase market clearing prices. Potential physical and economic withholding are evaluated in subsections A and B.

In the NYISO's market design, a competitive generator offer equals its marginal production cost. Absent market power, a supplier maximizes profits by producing output whenever its production cost is lower than the LBMP. However, a supplier with market power may profit from withholding when its losses from reduced outputs are offset by its gains from higher LBMPs. Accordingly, NYISO's market power mitigation measures cap suppliers' offers at their estimated marginal costs if their uncapped offers substantially exceed their estimated marginal cost and would materially impact LBMPs. In recent years, marginal cost estimates have become more uncertain during peak winter periods because of gas scheduling limitations and gas price volatility. As a result, the efficiency of mitigation measures depend on the accuracy of fuel cost estimates. Market power mitigation is evaluated in subsection C.

The NYISO co-optimizes the scheduling of energy and ancillary services in both the day-ahead and real-time markets. This co-optimization ensures that prices for energy and ancillary services reflect proper opportunity costs of diverting resources from energy to ancillary services. Co-optimization also reduces the potential for suppliers to exercise market power for a particular ancillary service product by allowing the market to flexibly shift resources between products, thereby increasing the competition to provide each product. Offer patterns for key operating reserve products in the day-ahead market are evaluated in subsection D.

Buyer behavior also influences energy prices. Under-scheduling load generally lowers day-ahead prices and leads to insufficient commitment for real-time needs. Alternatively, over-scheduling load tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load. The consistency of day-ahead load scheduling with actual load is evaluated in subsection E.

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. When virtual trading is profitable, it generally promotes convergence between day-ahead and real-time prices and tends to improve the efficiency of resource commitment and scheduling. The efficiency of virtual trading is evaluated in subsection F.

A. Potential Physical Withholding

We evaluate potential physical withholding by analyzing day-ahead and real-time generator deratings of economic capacity as well as economic capacity that is unoffered in real-time. A derating occurs when a participant reduces the maximum output available from the plant. This can occur for a planned outage, a long-term forced outage, a short-term forced outage, or without any logged outage record. A derating can be either partial (maximum output is reduced but greater than zero) or complete (maximum output is zero). Unoffered economic capacity in real-time includes quick-start units that do not offer in real-time and online baseload units that offer less than their full capability. The figures in this section show the quantity of deratings and unoffered real-time capacity as a percent of total Dependable Maximum Net Capability ("DMNC") from all generators in a region based on the most recent DMNC test value of each generator. *Short-term Deratings* include capacity that is derated for seven days or fewer. The remaining deratings are shown as *Long-Term Deratings.*[220]

We focus particularly on short-term deratings and real-time unoffered capacity because they are more likely to reflect attempts to physically withhold than are long-term deratings, since it is less costly to withhold a resource for a short period. Taking a long-term forced outage would cause a supplier to forego the opportunity to earn profits during more hours when the supplier does not have market power. Nevertheless, the figures in this subsection evaluate long-term deratings as well, since they still may be an indication of withholding.

We focus on suppliers in Eastern New York, since this area includes roughly two-thirds of the State's load, contains several areas with limited import capability, and is more vulnerable to the exercise of market power than is Western New York.

We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding. The figures in this subsection show the portion of derated and unoffered capacity that would have been economic based on Reference Levels and market prices.[221] This assessment determines economic commitment of baseload units based on day-ahead prices, considering start-up, minimum generation, and incremental costs. Economic dispatch of

220 For our analyses of physical and economic withholding, we exclude unoffered capacity from hydro, solar, wind, landfill-gas and biomass generators as well as nuclear units on planned maintenance outages.

221 This evaluation includes a modest threshold, which is described in subsection B as "Lower Threshold 1."

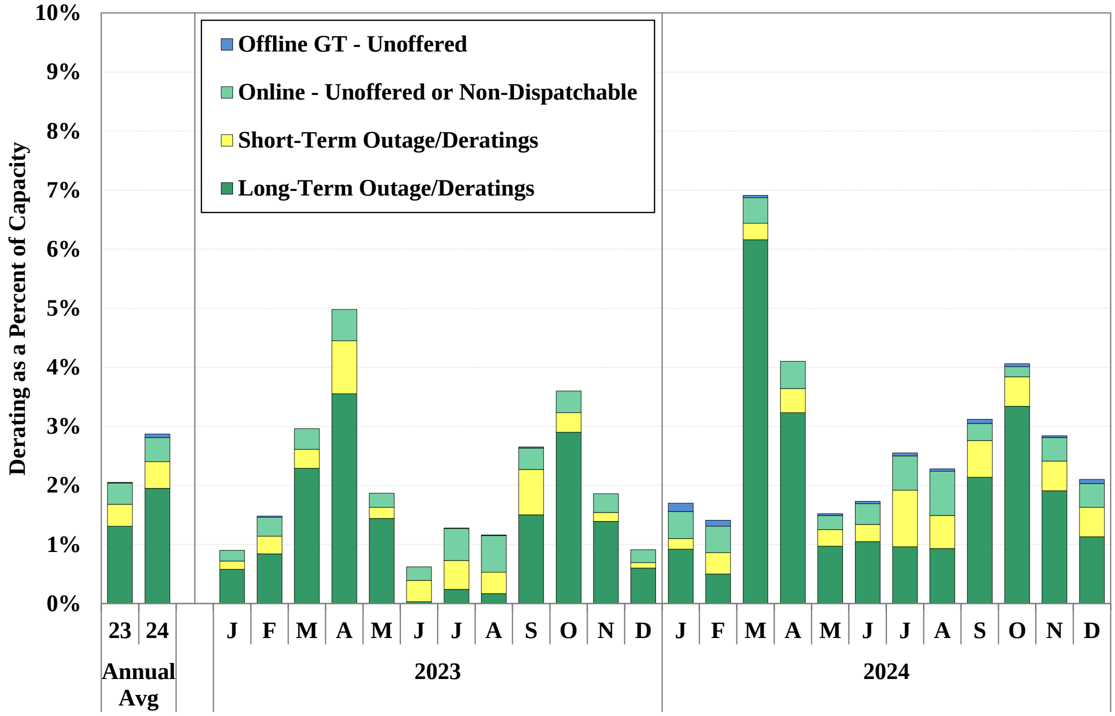
baseload units is based on RTD prices considering ramp rate limitations.[222] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[223]

Figure A-23 - Figure A-26: Unoffered Economic Capacity by Month, Load Level, & Portfolio Size

Figure A-23 and Figure A-24 show the broad patterns of deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2023 and 2024.

Most wholesale electricity production comes from baseload and intermediate-load generating resources. Higher-cost resources are used to meet peak loads and constitute a very small portion of the total supply. This causes the market supply curve to be comparatively flat at low and moderate output levels and steeply sloped at high output levels. Therefore, as demand increases from low load levels, prices rise gradually until demand approaches peak levels, at which point prices can increase quickly as the costlier units are required to meet load. The shape of the market supply curve has implications for evaluating market power, namely that suppliers are more likely to have market power in broad areas under higher load conditions.

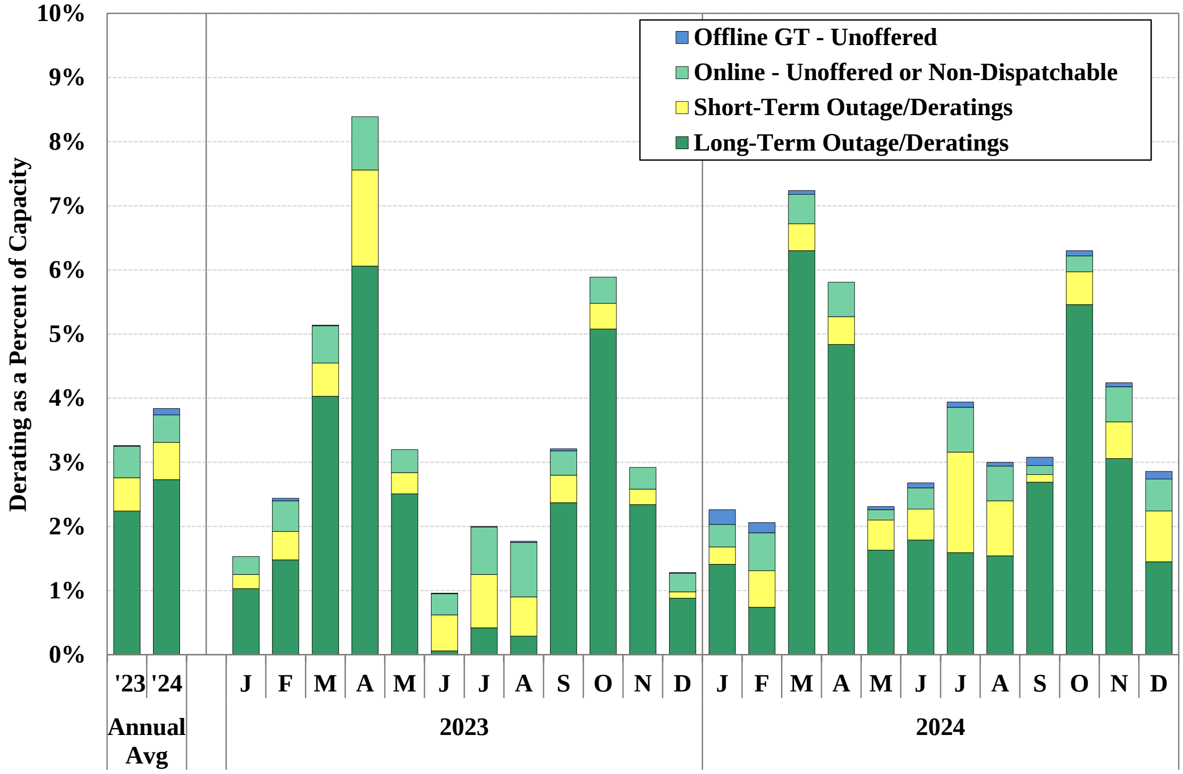
Figure A-23: Unoffered Economic Capacity by Month in NYCA
2023 – 2024



222 If a baseload unit was committed by the DAM, optimal dispatch and potential physical withholding of incremental energy ranges was evaluated at RTD prices, even if the units DAM reference costs were above the DAM prices.

223 In this paragraph, “prices” refers to both energy and reserves prices.

Figure A-24: Unoffered Economic Capacity by Month in East New York
2023 - 2024



To distinguish between strategic and competitive conduct, we evaluate potential physical withholding considering market conditions and participant characteristics that would tend to create both the ability and the incentive to exercise market power. Under competitive conditions, suppliers maximize profits by increasing their offer quantities during the highest load periods to sell more power at the higher peak prices. Thus, we expect competitive suppliers to schedule maintenance outages during low-load periods, whenever possible. Nonetheless, more frequent operation of generators during high load periods increases the frequency of forced outages, which can reduce the amount of capacity offered into the market. Capacity that is on forced outage is more likely to be economic during high-load periods than during low-load periods.

As noted previously, a supplier with market power is most likely to profit from withholding in periods when the market supply curve becomes steep (e.g., high-demand periods) because that is when prices are most sensitive to withholding. Hence, we evaluate the conduct relative to load and participant size in Figure A-25 and Figure A-26 to determine whether the conduct is consistent with workable competition.

Figure A-25: Unoffered Economic Capacity by Supplier by Load Level in New York
2023 – 2024

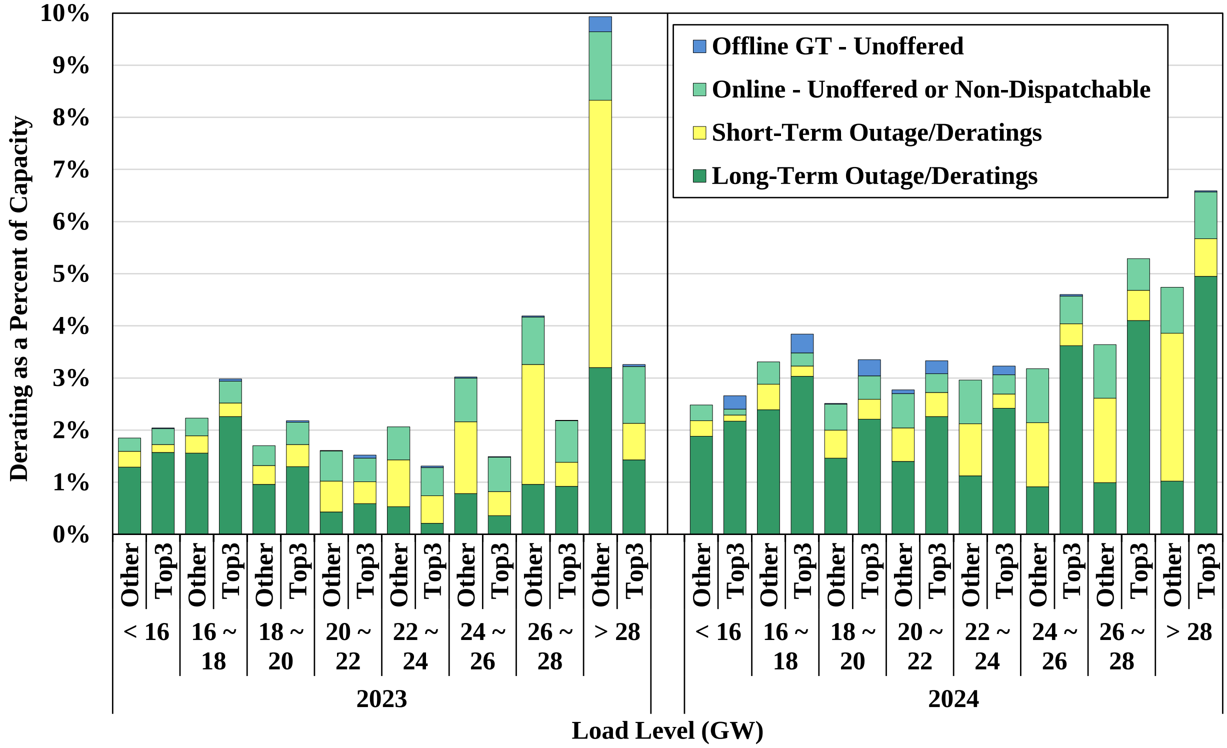
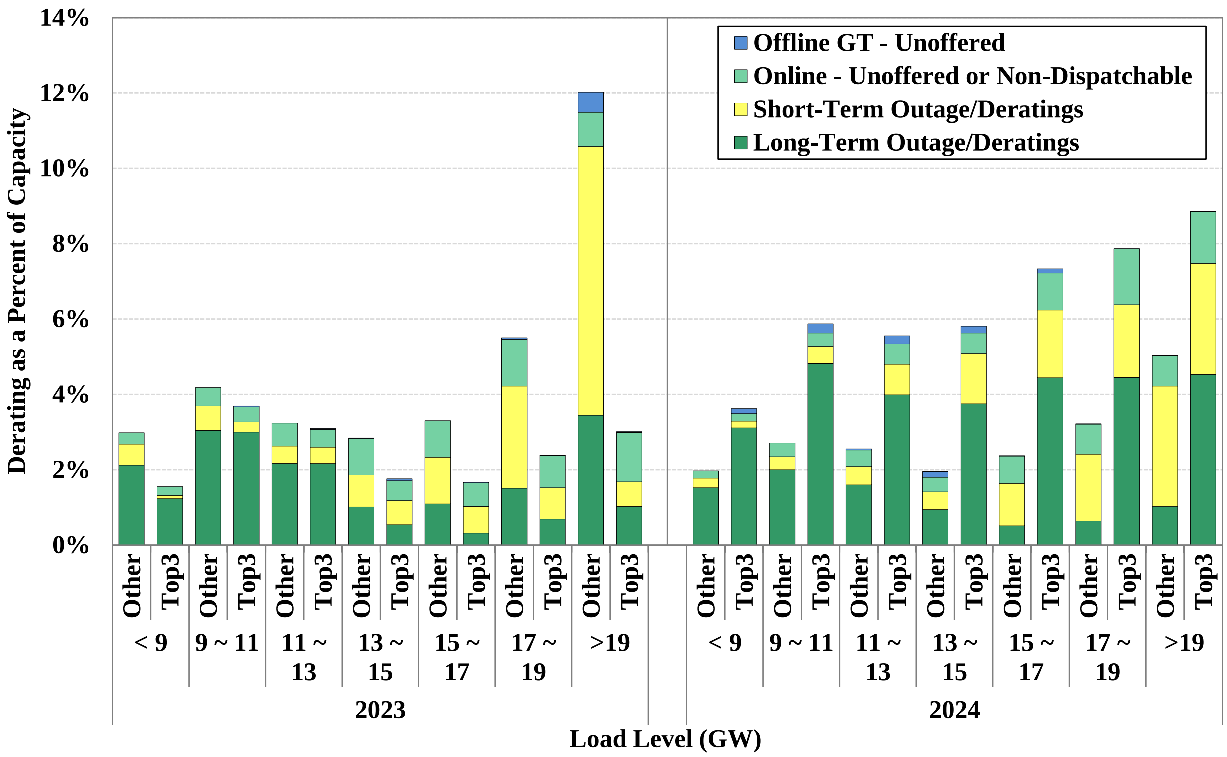


Figure A-26: Unoffered Economic Capacity by Supplier by Load Level in East New York
2023 – 2024



B. Potential Economic Withholding: Output Gap Metric

Economic withholding is an attempt by a supplier to inflate its offer price to raise LBMPs above competitive levels. In general, a supplier without market power maximizes profit by offering at marginal cost because inflated offer prices or other offer parameters prevent the unit from being dispatched when it would have been profitable. Hence, we analyze economic withholding by comparing a generator's supply offers with its reference levels, which is an estimate of marginal cost that is used for market power mitigation.[224, 225] An offer parameter is generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-27 to Figure A-30: Output Gap by Month, Supplier Size, and Load Level

One useful metric for identifying potential economic withholding is the "output gap." The output gap is the amount of generation that appears to be economic at the market clearing price but is not scheduled, either due to bids that exceed the reference levels or due to other factors.[226] We assume that the unit's competitive offer price is equal to its reference level. To determine whether a unit is economic, we evaluate whether it would have been economic to commit based on day-ahead prices and whether its incremental energy would have been economic to produce based on real-time prices. Since gas turbines can be started in real-time, they are evaluated based on real-time prices. Like the prior analysis of potential physical withholding, we examine the broad patterns of output gap in New York State and Eastern New York, and we address the relationship of the output gap to the market demand level and participant size.

The following four figures show the output gap using three thresholds: the state-wide mitigation threshold (i.e., the level used for mitigation outside New York City), which is the lower of $100 per MWh or 300 percent of a generator's reference level; and two additional thresholds: Threshold 1 is 25 percent of a generator's reference level, and Threshold 2 is 100 percent of a generator's reference level. The two non-mitigation thresholds are used to identify abuses of market power that do not trigger the thresholds specified in the tariff for imposition of mitigation measures. However, since there is uncertainty in the estimation of the marginal costs of individual units, lower thresholds are more likely to flag behavior that is actually competitive.

Like the analysis of deratings in the prior subsection, it is useful to examine the output gap by load level and size of supplier because the incentive to economically withhold resources is positively correlated with these factors. Hence, these figures indicate how the output varies as

224 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 23.3.1.4. For some generators, the reference levels are based on an average of the generators' accepted bids during competitive periods over the previous 90 days. The theory underlying this approach is that competitive conditions that prevail in most hours provide a strong incentive for suppliers to offer marginal costs. Hence, past accepted offers provide a benchmark for a generator's marginal costs. For some generators, the reference level is based on an estimate of its fuel costs, other variable production costs, and any other applicable costs.

225 Due to the Fuel Cost Adjustment (FCA) functionality, a generator's reference level can be adjusted directly by a generator for a particular hour or day to account for fuel price changes. The NYISO monitors these generator-set FCA reference levels and may request documentation substantiating a generator FCA.

226 The output gap calculation excludes capacity that is more economic to provide ancillary services.

load increases and whether the largest three suppliers exhibit substantially different conduct than other suppliers.

Figure A-27: Output Gap by Month in New York State

2023 – 2024

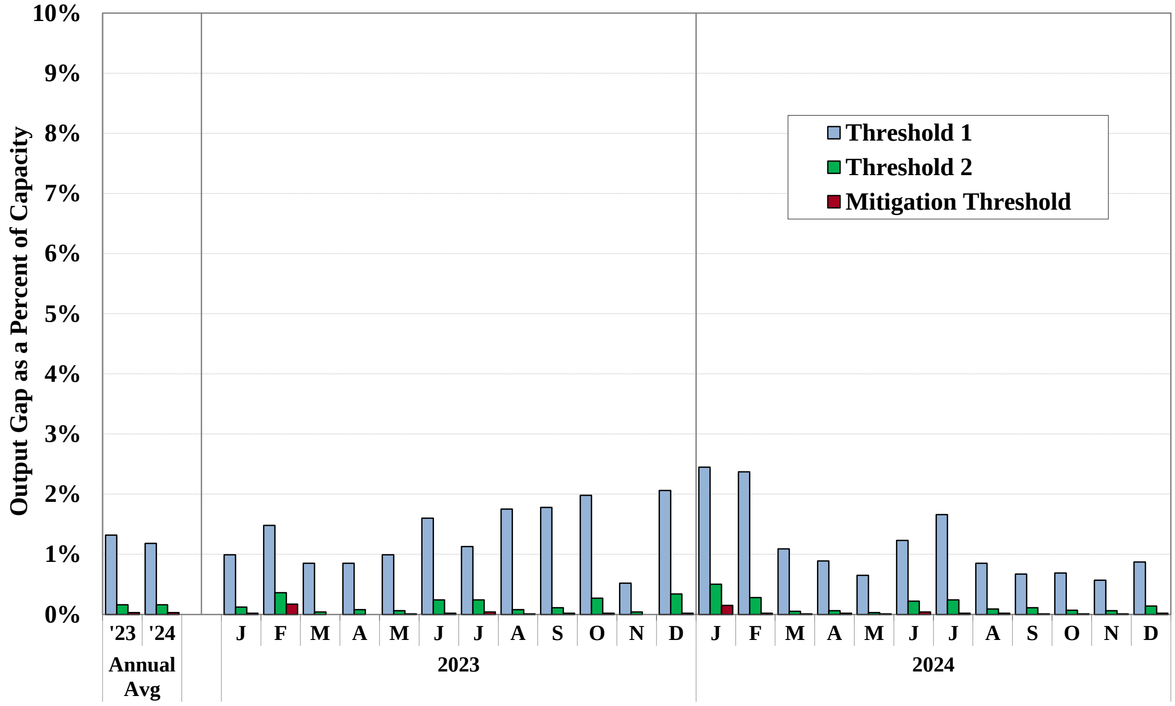


Figure A-28: Output Gap by Month in East New York

2023 - 2024

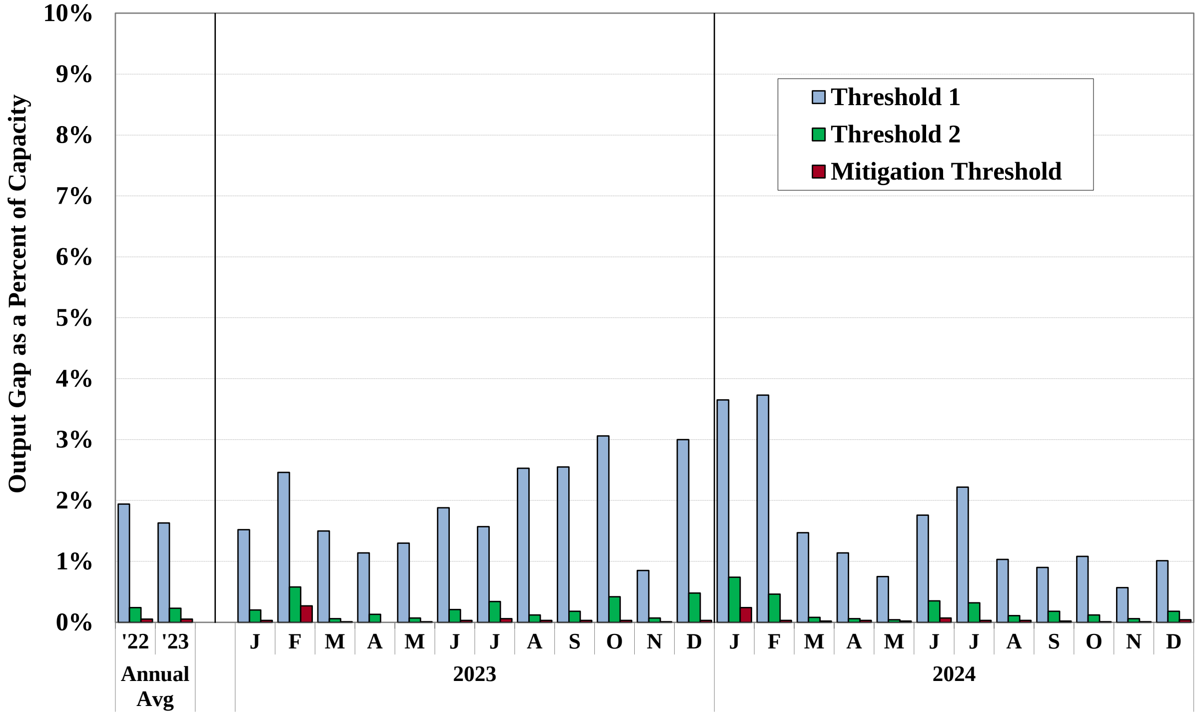


Figure A-29: Output Gap by Supplier by Load Level in New York State
2024

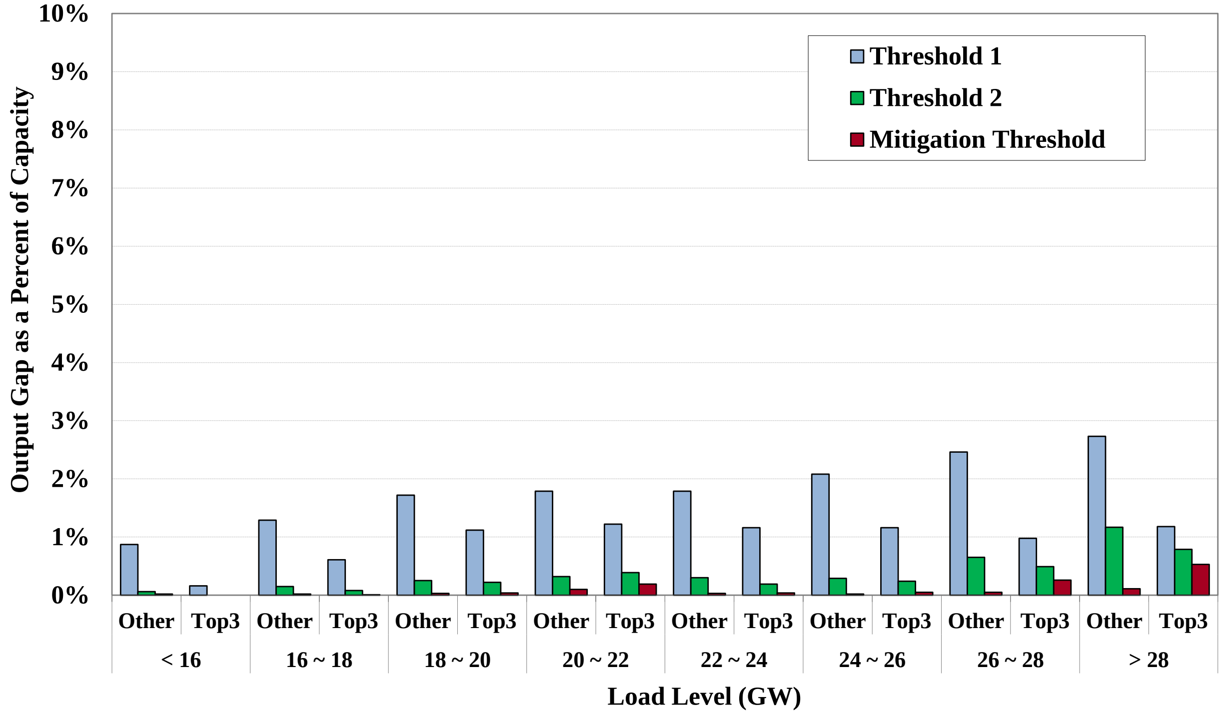
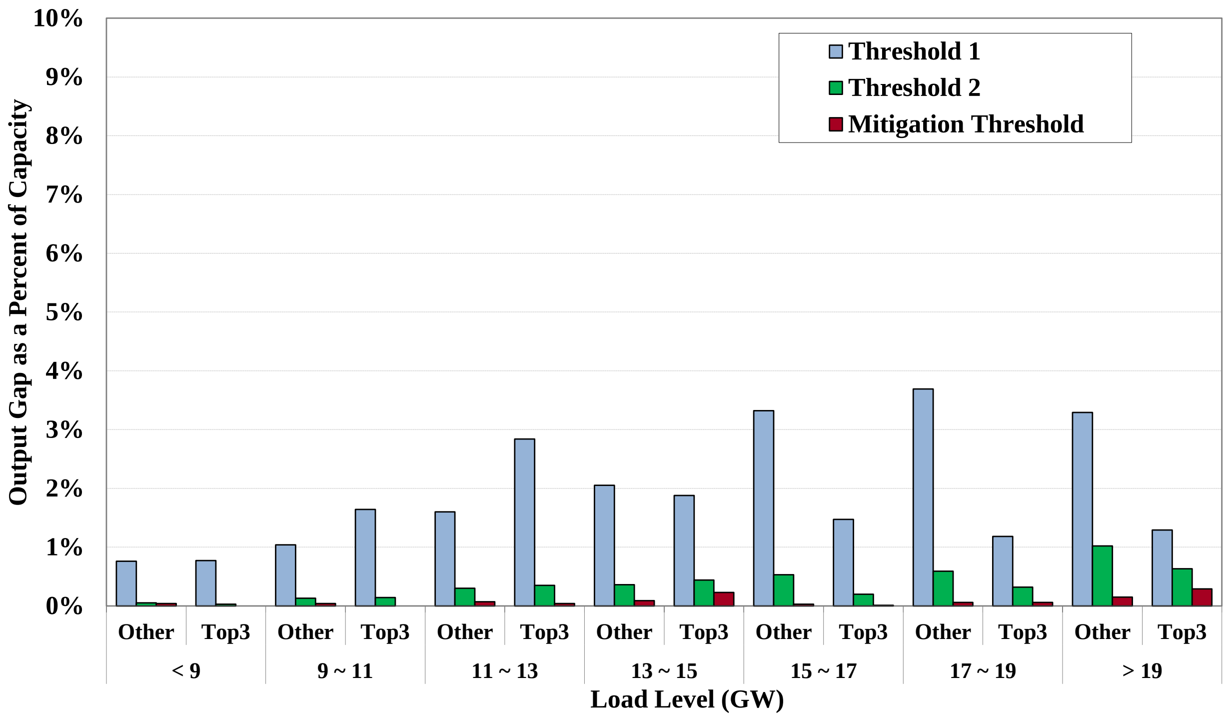


Figure A-30: Output Gap by Supplier by Load Level in East New York
2024



C. Day-Ahead and Real-Time Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. NYISO applies conduct and impact tests that can result in mitigation of a participant's bid parameters (i.e., incremental energy offers, start-up and minimum generation offers, and physical parameters). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds.[227] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The day-ahead and real-time market software is automated to perform conduct and impact tests and impose mitigation when appropriate. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while mitigating inflated offer prices that would otherwise lead to prices above competitive levels due to economic withholding.

When a transmission constraint is binding, one or more suppliers may be in a position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[228] This approach permits the in-city conduct and impact thresholds to increase as the frequency of congestion decreases, whether due to additional generation or increases in transmission capability. An in-city offer fails the conduct test if it exceeds the reference level by the threshold or more. In-city offers that fail the conduct test are tested for price impact by the market software. If their price impact exceeds the threshold, they are mitigated.

When local reliability criteria necessitate the commitment of additional generation, suppliers may be in a position to exercise market power due to the lack of competition in the local area. Hence, NYISO has more restrictive conduct and impact thresholds when a single supplier is pivotal for satisfying local reliability criteria outside New York City.[229] The tariff limits the start-up cost and minimum generation cost offers of such units to conduct thresholds of the higher of $10 per MWh or 10 percent of the reference level.[230]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with NYISO.[231] Mitigation can be reversed for several reasons:

227 See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

228 Threshold = (0.02 * Average Price * 8760) / Constrained Hours. This threshold is defined in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

229 In New York City, the start-up cost and minimum generation cost offers of units committed for local reliability are effectively subject to $0 thresholds. See NYISO Market Services Tariff, Section 23.5.2.1.

230 See NYISO Market Services Tariff, Section 23.3.1.2.3.

231 NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation. This occurs after the market date, so any effect of the mitigation on LBMPs is unchanged by un-mitigation.

- A generator's reference level is inaccurate and the supplier-initiated consultation with NYISO to increase the reference level before the generator was mitigated.
- A generator's reference level on a particular day is lower than the consultative reference level that NYISO approved for the generator before the generator was mitigated.[232]
- The generator took appropriate steps to inform NYISO of a fuel price change prior to being scheduled (through an FCA or other means), but the generator was still mitigated.
- A generator's fuel cost may change significantly by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day, so it may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

NYISO also reviews the markets for potential abuses of market power in the form of uneconomic overproduction from generation facilities. While the mitigation provisions for withholding aim to prevent a generator from underproducing in order to increase prices, mitigation provisions for uneconomic overproduction prevent generators from increasing output in order to reduce prices below competitive levels. There are several reasons why a market party operating a generator with local market power may be incentivized to over produce and reduce prices to benefits its portfolio, including:

- Create a constraint that raises prices downstream for other generators in its portfolio;
- Buy out of a day-ahead position at very low or negative LBMPs; and/or
- Benefit a financial position that profits from lower prices.

Similar to the economic and physical withholding provisions, uneconomic overproduction mitigation measures employ conduct and impact thresholds to identify such behavior.[233] The NYISO's established mitigation measures generally deter behavior that could lead to the three concerns listed above. However, we have identified a concern with the lack of financial incentives for intermittent generators to follow curtailment instructions under certain conditions. When these resources do not follow curtailment instructions, it threatens system security and may lead to inefficient market operations. Appendix Section V.C provides analysis of this issue and our recommendation to address it.

Figure A-31 & Figure A-32: Summary of Day-Ahead and Real-Time Mitigation

Figure A-31 and Figure A-32 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2023 and 2024. These figures do not include guarantee payment mitigation that occurs in the settlement system.

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232 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.3.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

233 See tariff sections 23.3.1.3 and 23.3.2.1.1.1.

Figure A-31: Summary of Day-Ahead Mitigation
2023 – 2024

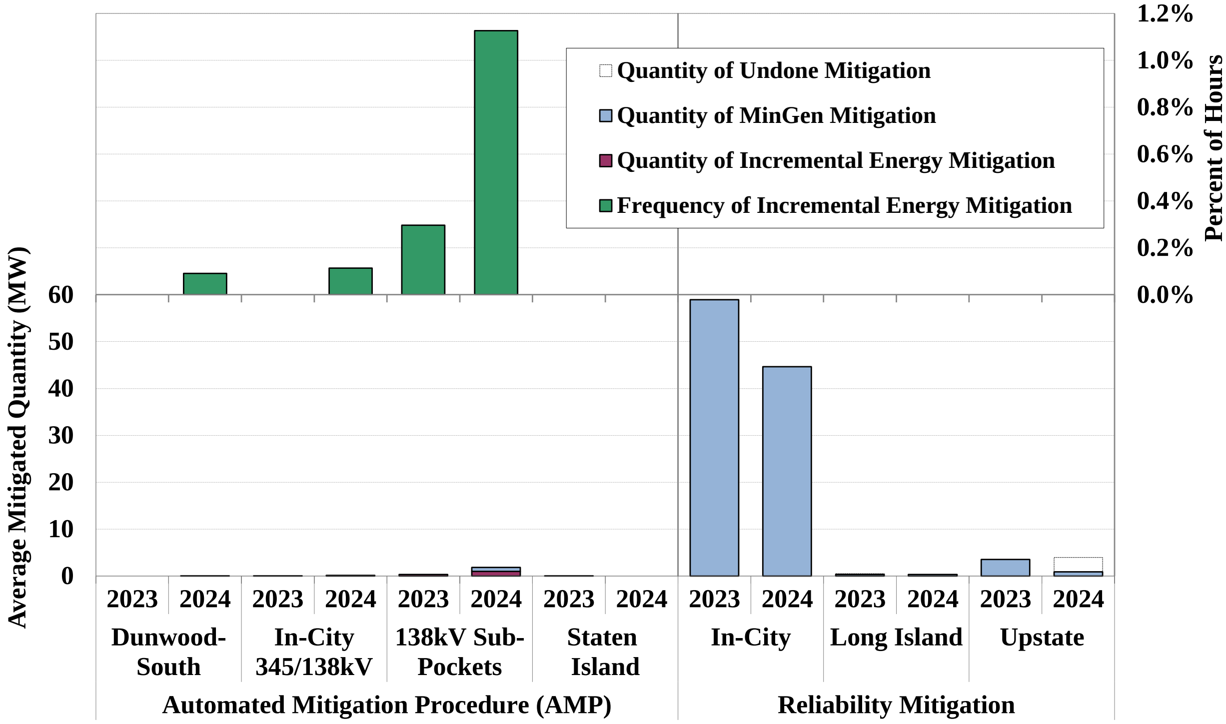
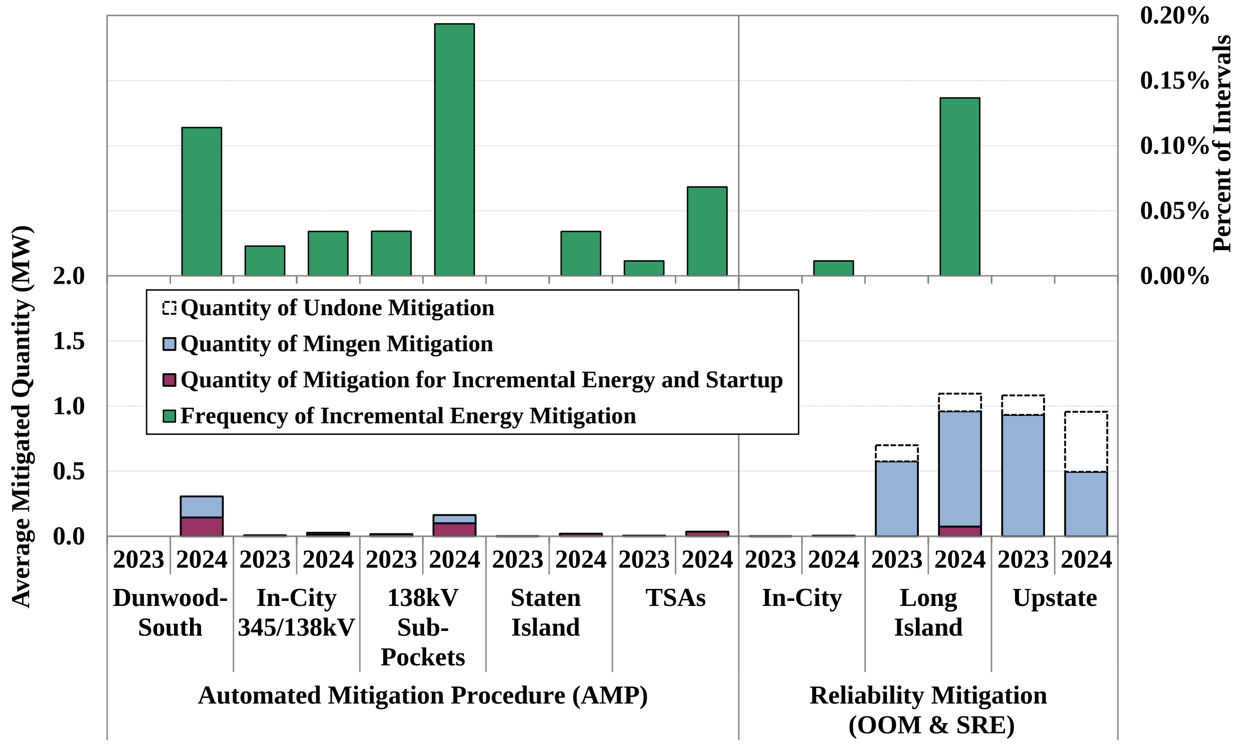


Figure A-32: Summary of Real-Time Mitigation
2023 – 2024



The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion that was unmitigated). Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e. MinGen).[234] In each figure, the left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

D. Operating Reserves Offers in the Day-Ahead Market

Multiple factors, including opportunity costs, demand curves, and offers, determine the prices of ancillary services. The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. Co-optimization causes the prices of energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.

The ancillary services markets use demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be satisfied at a cost lower than the demand curve, the system is in shortage and the reserve demand curve value is included in the reserve price and the energy price. This approach is recognized for producing efficient prices during shortages of reserves because it provides a mechanism for reflecting the value of reserves in the price of energy during shortages.

This subsection focuses on offer patterns in the day-ahead market for several key operating reserve products. In an efficient market, we expect suppliers to respond to predictable differences between day-ahead and real-time prices by raising or lowering their offer prices in the day-ahead market. However, the high volatility of real-time clearing prices is difficult to predict in the day-ahead market. High volatility of real-time prices is a source of risk for suppliers that sell reserves in the day-ahead market, since suppliers must forego real-time scarcity revenues if they have already sold reserves in the day-ahead market. Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

Figure A-33 to Figure A-34: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement and Eastern New York 10-Minute Reserve Requirement

Figure A-33 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of the past three years. These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers, although they are not shown separately in the figure. Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included in this evaluation, since they directly affect the reserve prices.

234 Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

The stacked bars in the Figure A-33 show the amount of reserve offers in selected price ranges for West New York (Zones A to E), East New York (Zones F to J), and NYCA (excluding Zone K). Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e., SENY, East, NYCA). As a result, Long Island reserve offers have little impact on NYCA reserve prices.

The black bar in the figure represents the equivalent average 30-minute reserve requirements for areas outside Long Island. This is calculated as NYCA 30-minute reserve requirement *minus* 30-minute reserves scheduled on Long Island. Where the line intersects the bar provides a rough indication of reserve prices, which, however, is generally lower than actual reserve prices because opportunity costs are not reflected in the figure.

Figure A-33: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

Committed and Available Offline Quick-Start Resources, 2022 – 2024

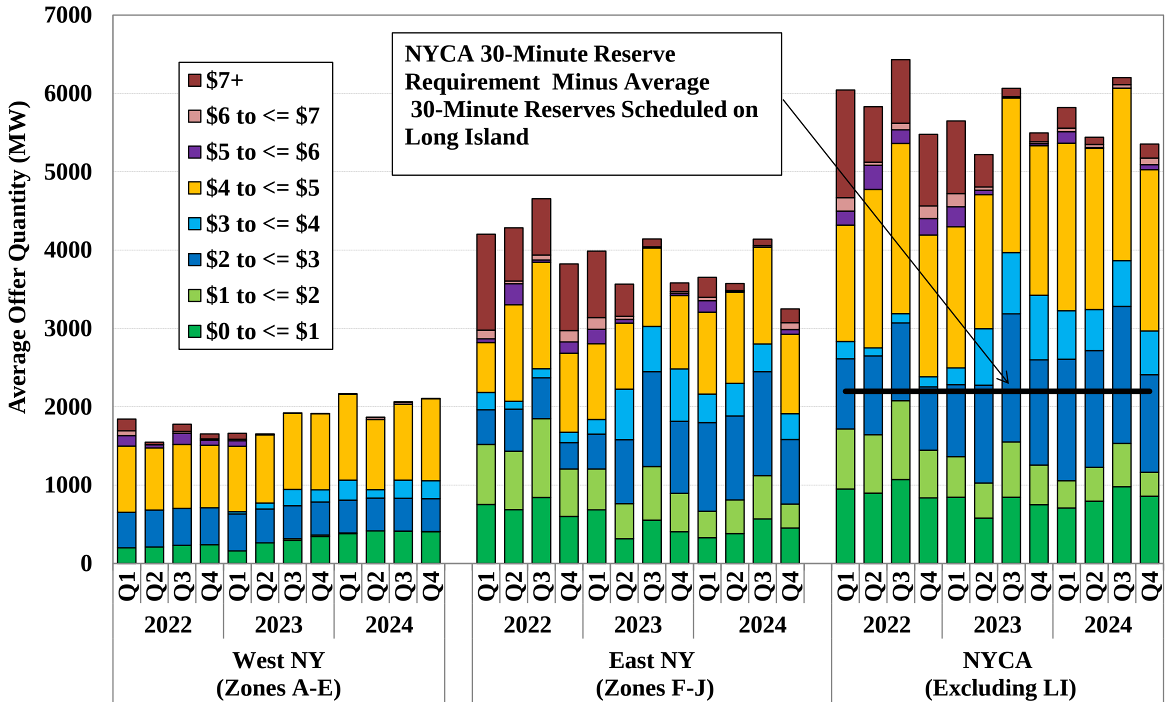
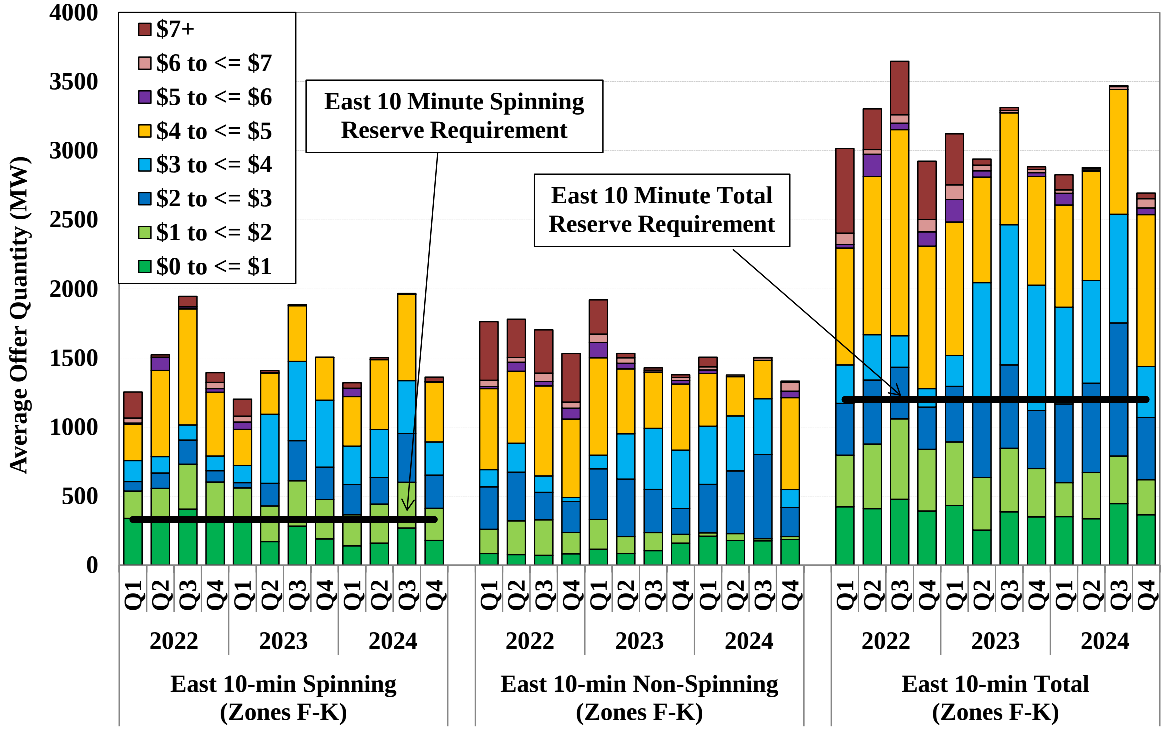


Figure A-34 summarizes offers that can satisfy the Eastern New York reserves requirement and shows generator offers for 10-minute reserves from committed resources and available offline quick-start resources. The first set of stacked bars shows the offers from generators for the 10-minute spinning requirement (set at 330 MWs and shown with a black bar) while the second set of stacked bars show the offers for 10-minute non-spinning reserves. The final stack is the sum of the first two and is shown with a black bar designating the Eastern NY total 10-minute requirement of 1200 MWs. Similar to Figure A-33, the intersection of the black bars with the stacked lines is a rough indication of reserve prices but is generally lower than actual reserve prices because opportunity costs are not reflected in the figure.

Figure A-34: Day-Ahead Reserve Offers that Satisfy ENY 10-Minute Reserve Requirement

Committed and Available Offline Quick-Start Resources, 2022 - 2024



E. Analysis of Load Bidding and Virtual Trading

In addition to screening suppliers for physical and economic withholding, it is important to evaluate how buyer behavior influences energy prices. Therefore, we evaluate whether load bidding is consistent with the principles of workable competition. Load can be scheduled in one of the following five ways:

- **Physical Bilateral Contracts** – These schedules allow participants to settle transmission charges (i.e., congestion and losses) with the NYISO between two points while privately settling the commodity sale with their counterparties. This does not represent all bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately (e.g., contracts for differences).
- **Day-Ahead Fixed Load** – This represents load scheduled in the day-ahead market for receipt at a specific bus, regardless of the day-ahead price. It is equivalent to a load bid with an infinite bid price.
- **Price-Capped Load Bids** – These are load bids submitted into the day-ahead market with a specific bid price, indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[235]
- **Virtual Load Bids** – These are bids to purchase energy in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load

235 For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

scheduled in the day-ahead market is subsequently sold back in the real-time market. The virtual buyer earns or pays the difference between the day-ahead and real-time prices. Virtual trading is currently allowed only at the load zone level.

- **Virtual Exports** – These are external transactions in the export direction that are scheduled in the day-ahead market but are withdrawn or bid at high price levels in real time. They function similarly to virtual load bids but are placed at the external proxy buses rather than at the eleven load zones.

Each of these load categories is important because they tend to increase the amount of physical resources scheduled in the day-ahead market. Conversely, virtual supply and virtual imports tend to reduce the amount of physical resources scheduled in the day-ahead market. Virtual supply is energy offered for sale in the day-ahead market, with an offer price indicating the minimum amount the market participant is willing to accept. Virtual supply sold in the day-ahead market is subsequently purchased back in the real-time market.

Figure A-35: Day-Ahead Load Schedules versus Actual Load

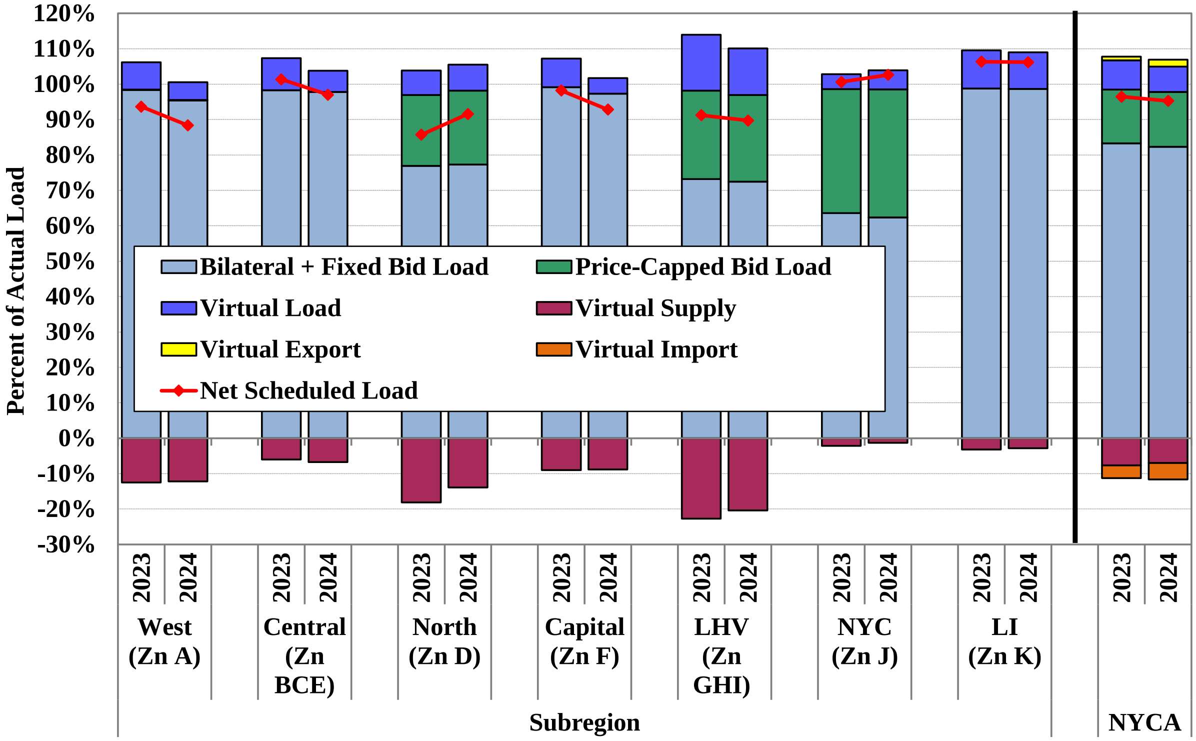
Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit them well in advance of real-time, often before they can be certain that the unit will be economic. The day-ahead market provides suppliers with a means of being committed only when economically justified. These suppliers are more likely to sell into the day-ahead market if day-ahead prices are generally consistent with real-time prices. Thus, efficient unit commitment relies on consistency between the day-ahead and the real-time markets. The following figure evaluates the consistency between day-ahead load scheduling patterns and actual load, offering insights into the overall efficiency of the day-ahead market.

In a well-functioning market, day-ahead load schedules are expected to be generally consistent with actual load. Under-scheduling load can lead to lower day-ahead prices and insufficient commitment for real-time needs, while over-scheduling may raise day-ahead prices above real-time prices. As a result, market participants have incentives to schedule load amounts that are consistent with real-time load.

The following figure shows day-ahead load schedules and bids as a percentage of real-time load during daily peak load hours in 2023 and in 2024 at various locations in New York, based on an annual average. Since virtual load (including virtual exports) has the same effect on day-ahead prices and resource commitment as physical load, they are shown together in this analysis. Conversely, virtual supply (including virtual imports) has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as negative load for the purposes of this analysis.

For each period, physical load and virtual load are represented by bars in the positive direction, while virtual supply is represented by bars in the negative direction. Net scheduled load, indicated by the line, is the sum of scheduled physical and virtual load minus scheduled virtual supply. Virtual imports and exports are shown only for NYCA and are not displayed for individual sub-areas in New York.

Figure A-35: Day-Ahead Load Schedules versus Actual Load
By Region, 2023 – 2024



F. Virtual Trading in New York

Virtual trading plays an important role in market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. Virtual trading in the day-ahead consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual bids and offers provide liquidity to the day-ahead because they constitute a substantial share of the price-sensitive supply and demand that establish efficient day-ahead prices.

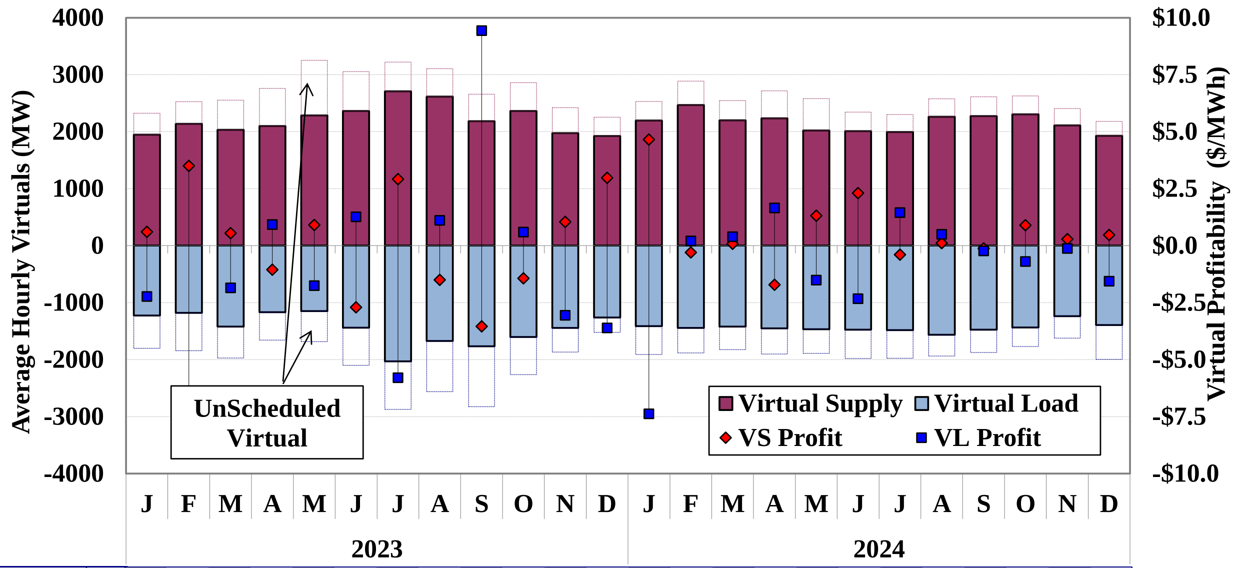
Virtual transactions that are scheduled in the day-ahead market settle against real-time energy prices. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. If prices are lower in the day-ahead market than in the real-time market, a virtual trader may purchase energy in the day-ahead market and sell it back in the real-time market, which will tend to increase day-ahead prices and improve price convergence with the real-time market. Hence, profitable virtual transactions improve the performance of the day-ahead market. The New York ISO currently allows virtual traders to schedule transactions to arbitrage the price differences at the load zone level between day-ahead and real-time.

Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as Virtual Imports and Virtual Exports in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that are scheduled in the day-ahead market do not flow in real-time). Since the virtual imports and exports have a similar effect on scheduling and pricing as virtual load and supply, they are evaluated as part of virtual trading in this section.

Figure A-36: Virtual Trading Volumes and Profitability

The figure summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2023 and 2024. The amount of scheduled virtual supply in the figure includes scheduled virtual supply at the load zones and virtual imports at the external proxy buses. Likewise, the amount of scheduled virtual load in the chart includes scheduled virtual load at the load zones and scheduled virtual exports at the external proxy buses. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market compared to the price at which these positions were covered in the real-time market.[236,237]

Figure A-36: Virtual Trading Volumes and Profitability
2023 – 2024



		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	170	455	343	243	275	130	360	243	244	166	198	136	293	103	132	80	129	224	232	125	44	100	81	231
	%	5%	14%	10%	7%	8%	3%	8%	6%	6%	4%	6%	4%	8%	3%	4%	2%	4%	6%	7%	3%	1%	3%	2%	7%
Loss > 50% of Avg. Zone Price	MW	206	412	377	285	296	164	415	322	156	213	255	141	267	145	151	88	148	214	237	139	56	103	151	233
	%	7%	12%	11%	9%	9%	4%	9%	8%	4%	5%	7%	4%	7%	4%	4%	2%	4%	6%	7%	4%	1%	3%	5%	7%

The table below the figure shows a screen for relatively large profits or losses, which identifies virtual transactions with gross profits (or losses) larger than 50 percent of the average zone (or proxy bus) price. For example, an average of 231 MW of virtual transactions (or 7 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in

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236 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

237 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

December of 2024. Large profits may be an indicator of a modeling inconsistency, while sustained losses may be an indicator of potential manipulation of the day-ahead market.

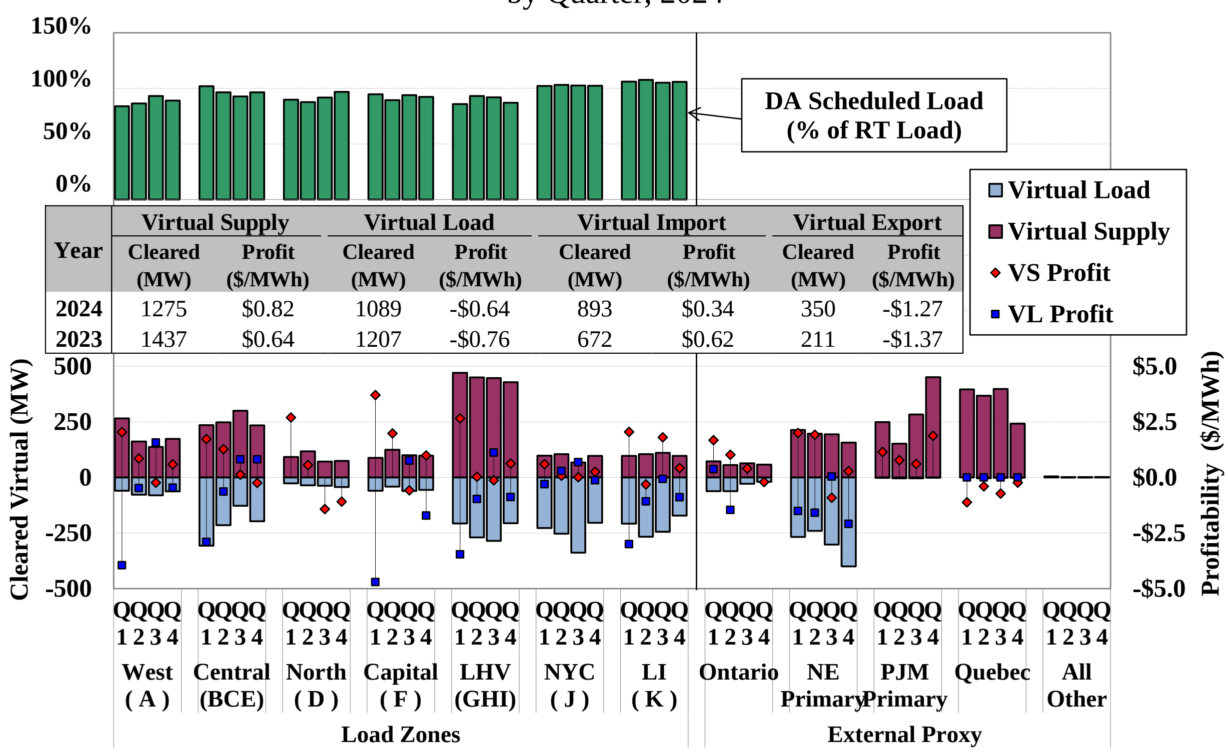
Figure A-37: Virtual Trading Activity by Region

Figure A-37 summarizes virtual trading by geographic region. The eleven zones in New York are broken into seven geographic regions based on typical congestion patterns. Zone A (the West Zone) is shown separately because of increased congestion in recent years. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas. The figure also shows virtual imports and exports with neighboring control areas. The Ontario proxy bus, the primary PJM proxy bus (i.e., the Keystone proxy bus), and the primary New England proxy bus (i.e., the Sandy Pond proxy bus) are evaluated separately from all other proxy buses.

The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the seven regions and four groups of external proxy buses in each quarter of 2024. Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW. The upper portion of the figure shows the average day-ahead scheduled load (as a percentage of real-time load) at each geographic region. The table in the middle compares the overall virtual trading activity in 2023 and 2024.

Figure A-37: Virtual Trading Activity by Region

by Quarter, 2024



Year	Virtual Supply Cleared (MW)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW)	Virtual Export Profit ($/MWh)
2024	1275	$0.82	1089	-$0.64	893	$0.34	350	-$1.27
2023	1437	$0.64	1207	-$0.76	672	$0.62	211	-$1.37

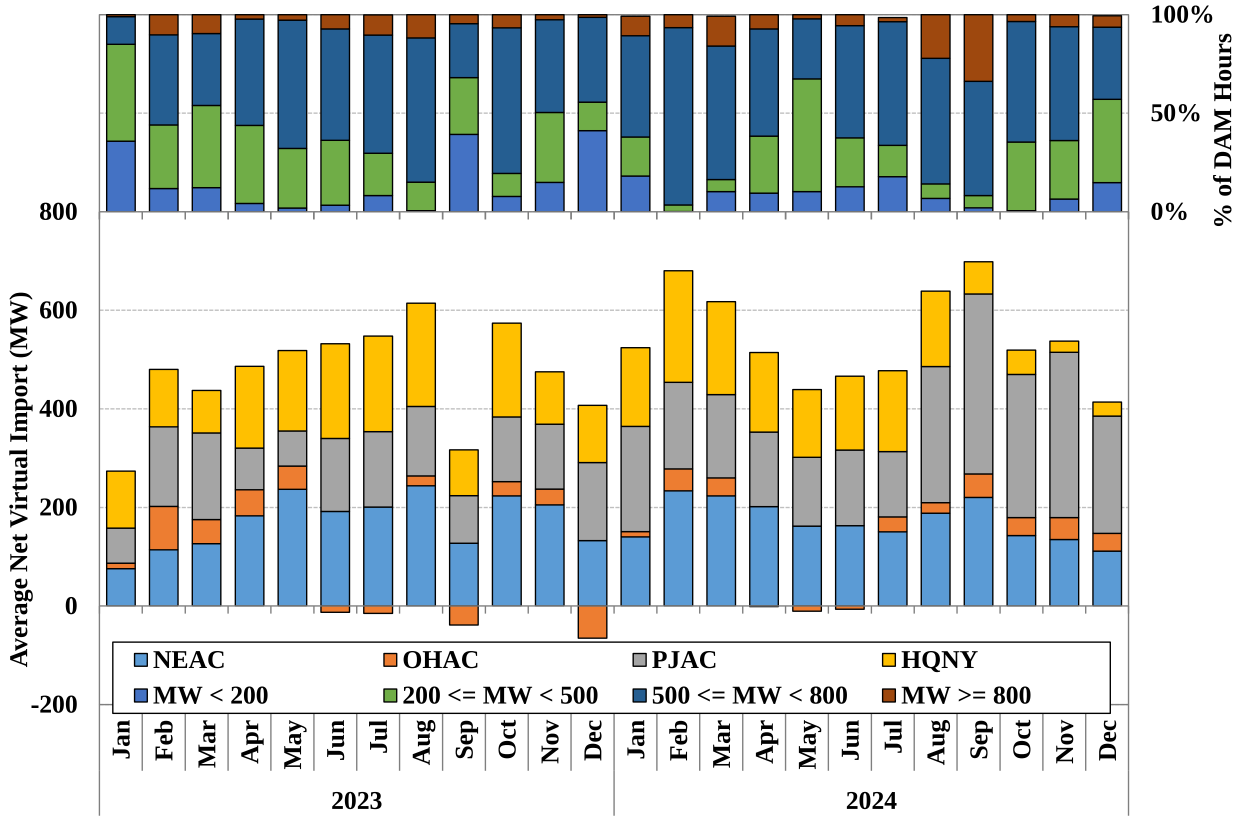
Figure A-38: Virtual Imports and Exports in the Day-ahead Market

The following chart evaluates scheduled virtual imports and exports in the day-ahead market. In this analysis, virtual imports and exports are defined as external transactions that are scheduled in the day-ahead market but withdrawn from the real-market market (i.e., no real-time bids submitted). Virtual wheels are excluded from this analysis.

The bottom portion of the chart shows the hourly average quantity of net virtual imports for each month. The bars represent the average net virtual imports scheduled across the four primary interfaces between NYISO and neighboring control areas. Virtual imports and exports are rare across the Scheduled-Line interfaces, which are excluded from this analysis.

The top portion of the chart shows the percentage of hours in each month when total net virtual imports across the four primary interfaces fall into the following ranges: (a) less than 200 MW; (b) between 200 and 500 MW; (c) between 500 and 800 MW; and (d) more than 800 MW.

Figure A-38: Virtual Imports and Exports in the Day-Ahead Market
by Month, 2023 - 2024



III. TRANSMISSION CONGESTION

Congestion arises when the transmission network is bottlenecked, limiting dispatch of the least expensive generators to satisfy system demand. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from lower-cost resources.

The day-ahead market is a forward market that facilitates financial transactions among participants. NYISO allows market participants to schedule transactions in the day-ahead market based on the predicted transmission capacity, resulting in congestion when some purchase bids and sell offers in merit order are not scheduled to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales scheduled in the day-ahead and real-time markets based on the congestion component of the LBMP. Bilateral transactions scheduled through the ISO are charged the difference between the LBMPs of the two locations (i.e., the price at the sink minus the price at the source).

Market participants can hedge congestion charges in the day-ahead market by owning Transmission Congestion Contracts ("TCCs"), which entitle the holder to payments corresponding to the congestion charges between and the source and sink locations. For example, if a participant holds 150 MW of TCCs from zone A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and zone A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the points.

Incremental changes in generation and load from the day-ahead market to the real-time market are subject to congestion charges or payments in the real-time market. As in the day-ahead market, charges for real-time bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract in the real-time market. There are no TCCs for real-time congestion.

This section summarizes the following aspects of transmission congestion and locational pricing:

- Congestion Revenues and Patterns – Subsections A, B, and C evaluate congestion revenues collected by the NYISO from the day-ahead market and patterns of congestion in the day-ahead and real-time markets.
- Constraints Requiring Frequent Out-of-Market Actions – Subsection D evaluates the management of transmission constraints that are frequently resolved using out-of-market actions, including 115 kV and 69 kV networks in New York.
- Linear Constraints to Model Long Island East End TVR Requirements – Subsection E describes a modeling approach to more efficiently schedule and price resources to satisfy the Transient Voltage Recovery ("TVR") requirements on the East End of Long Island.
- Congestion Revenue Shortfalls – Subsection F analyzes congestion shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- Transmission Line Ratings – Subsection G analyzes the potential congestion benefit of using ambient-temperature adjusted line ratings in the market model.
- TCC Prices and Day-Ahead Market Congestion – Subsection H reviews the consistency of TCC prices and day-ahead congestion, which determine payments to TCC holders.
- Transitioning Physical Contracts to Financial Rights – Subsection I presents a concept for modernizing contracts for physical power delivery that pre-date the NYISO market to financial rights that would allow key transmission facilities to be used more efficiently.

A. Summary of Congestion Revenue and Shortfalls

This subsection summarizes congestion revenues and shortfalls that are collected and settled through the NYISO markets. Most congestion revenues are collected through the day-ahead market, which we refer to as *day-ahead congestion revenues.* These are collected by NYISO when power is scheduled to flow across congested interfaces in the day-ahead market. The revenue collected is equal to the marginal cost of relieving the constraint (i.e., constraint shadow price) in the day-ahead market multiplied by the scheduled flow across the constraint in the day-ahead market.[238]

In addition to day-ahead congestion revenues, NYISO incurs two types of shortfalls that occur when there are inconsistencies between the transmission capability modeled in the TCC market, the day-ahead market, and the real-time market:

- *Balancing Congestion Shortfalls* – These arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.[239] To reduce flows in real time below the day-ahead schedule, the NYISO must redispatch generators by increasing generation downstream of the constraint and reducing generation upstream of the constraint. These redispatch costs (i.e., the difference between the payments for increased generation and the revenues from reduced generation in the two areas) are the balancing congestion shortfall that is recovered through uplift.
- *Day-ahead Congestion Shortfalls* – These occur when the day-ahead congestion revenues collected by NYISO are less than the payments to TCC holders. Shortfalls generally arise when the quantity of TCCs sold on a path exceeds the transfer capability of the path modeled in the day-ahead market when it is congested.[240] Day-ahead congestion shortfalls equal the difference between payments to TCC holders and day-ahead congestion revenues. These are partly offset by the revenues from selling excess TCCs.

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238 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000 in that hour (100 MW * $50/MWh).

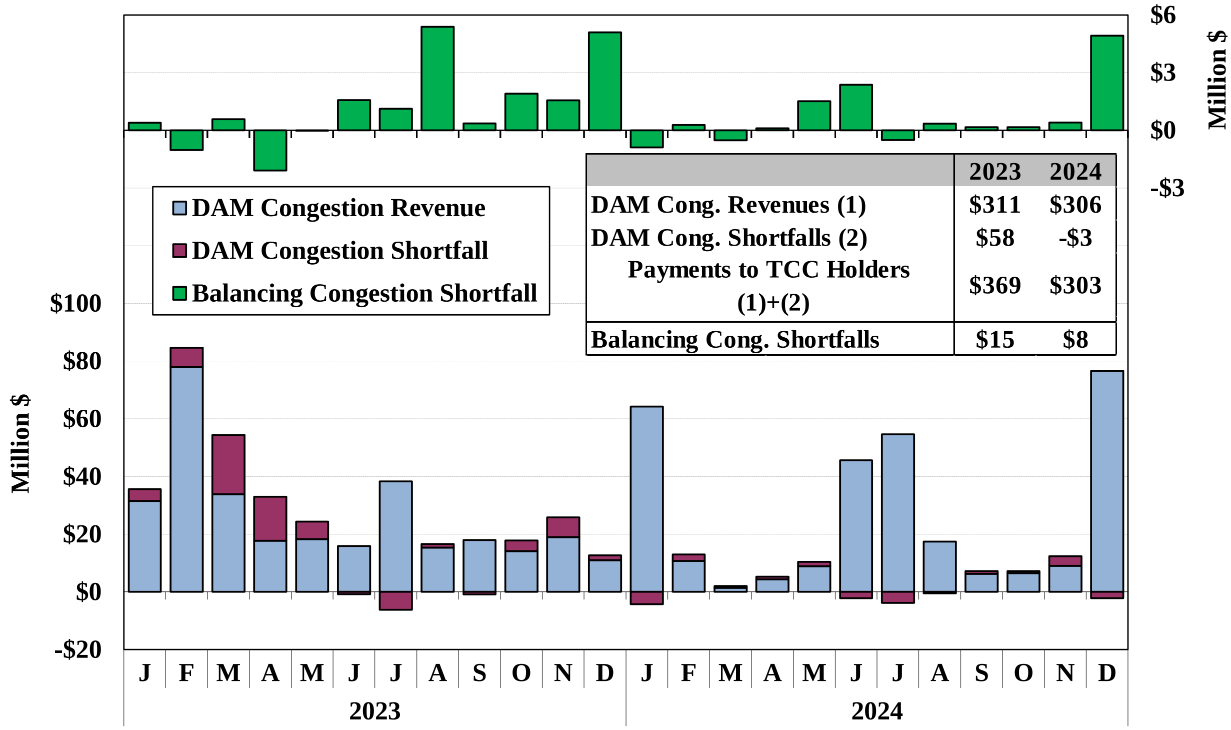
239 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $70/MWh).

240 For example, suppose 120 MW of TCCs are sold across a particular line. If 100 MW is scheduled to flow when the constraint has a shadow price of $50/MWh in an hour in the day-ahead market, the NYISO will have a day-ahead congestion shortfall of $1,000 in that hour ((120 MW – 100 MW) * $50/MWh).

Figure A-39: Congestion Revenue Collections and Shortfalls

Figure A-39 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2023 and 2024. The upper portion of the figure shows balancing congestion shortfalls. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls and the sum of these two categories is equal to the total net payments to TCC holders in each month. The table in the figure reports these categories on an annual basis.

Figure A-39: Congestion Revenue Collections and Shortfalls
2023 - 2024



B. Congestion on Major Transmission Paths

Transmission lines moving power from low-cost to high-cost areas provide considerable value. In New York, eastern supply is generally more expensive than western supply, but most demand is in the East. This creates transmission bottlenecks from West to East, leading to significant congestion-related price differences between regions. This subsection examines congestion patterns in the day-ahead and real-time markets.

In the day-ahead market, the NYISO schedules generation and load based on the bids and offers submitted by market participants and the assumed transfer capability of the transmission network. When scheduling between regions reaches the limits of the transmission network, congestion price differences arise between regions in the day-ahead market.

Market participants submit bids and offers in the day-ahead market that reflect their expectations of real-time prices and congestion, so day-ahead congestion prices are generally consistent with real-time congestion prices. To the extent that differences arise between day-ahead and real-time congestion patterns, it suggests that unexpected operating conditions may have occurred in the real-time market. Consistency between day-ahead and real-time prices is beneficial for market efficiency because it helps ensure that the resources committed each day are the most efficient ones to satisfy the system needs in real-time. Therefore, it is useful to evaluate the consistency of congestion patterns between the day-ahead and real-time markets.

Figure A-40 to Figure A-42: Day-Ahead and Real-Time Congestion by Path

Figure A-40 to Figure A-42 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-40 compares these quantities in 2023 and 2024 on an annual basis, while Figure A-41 and Figure A-42 show the quantities separately for each quarter of 2024. The figures measure congestion in two ways: [241]

- The frequency of binding constraints; and
- The value of congestion, which is equal to the marginal cost of relieving the constraint (i.e., constraint shadow cost) multiplied by the scheduled flow across the constraint.[242]

In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments. In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows settle at day-ahead prices rather than real-time prices. Nonetheless, the real-time congestion value provides the economic significance of congestion in the real-time market. The figure groups congestion along the following transmission paths:

- West Zone Lines: Transmission lines in the West Zone.
- West to Central: Primarily West-to-Central interface, Dysinger East interface, and transmission facilities in the Central Zone.
- North to Central: Primarily transmission facilities within and out of the North Zone.
- Central to East: Transmission facilities from Western and Central New York to Eastern New York, including the Central-to-East interface.
- Capital to Hudson Valley: Primarily lines leading into Southeast New York.
- Hudson Valley to Dunwoodie: Lines and interfaces from Hudson Valley to Dunwoodie.
- New York City: Lines leading into and within the NYC 345 kV system, line leading into and within New York City load pockets and groups of lines into load pockets that are modeled as interface constraints.
- Long Island: Lines leading into and within Long Island.
- External Interface: Congestion related to the total transmission limits or ramp limits of the external interfaces.

241 Binding transmission constraints with a shadow cost lower than $0.1/MWh are not included.

242 The shadow cost of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

Figure A-40: Day-Ahead and Real-Time Congestion by Transmission Path
2023 – 2024

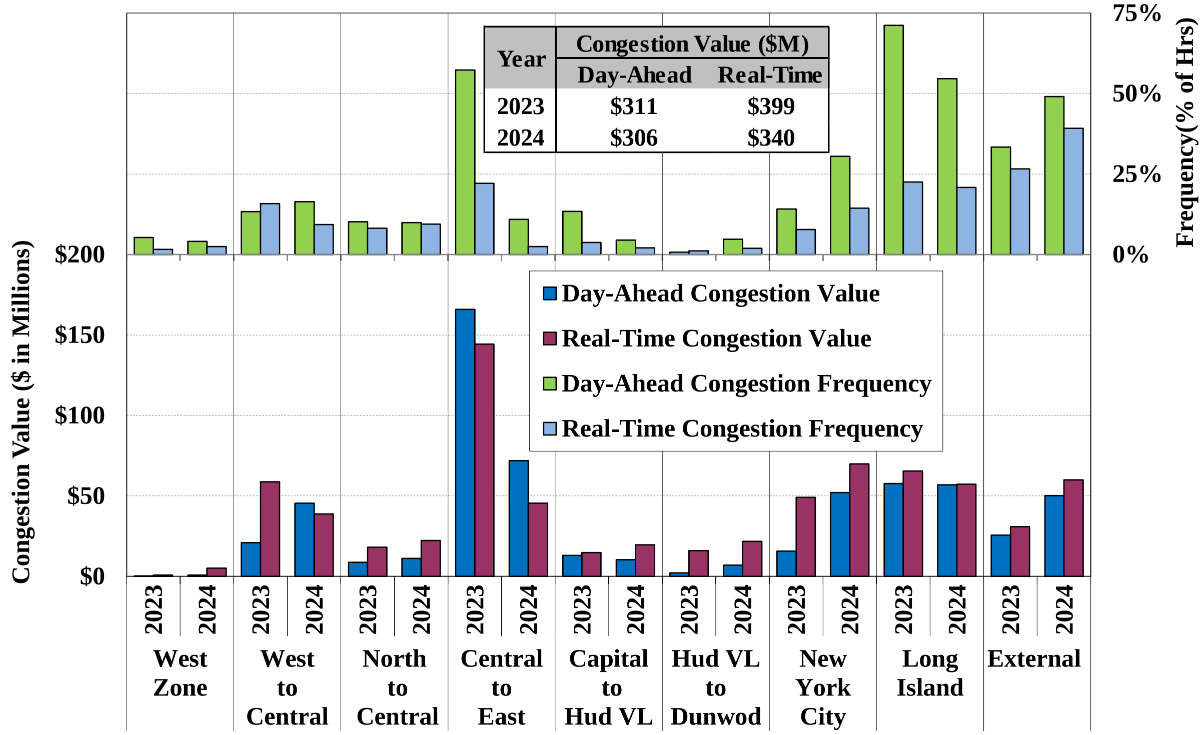


Figure A-41: Day-Ahead Congestion by Transmission Path
By Quarter, 2024

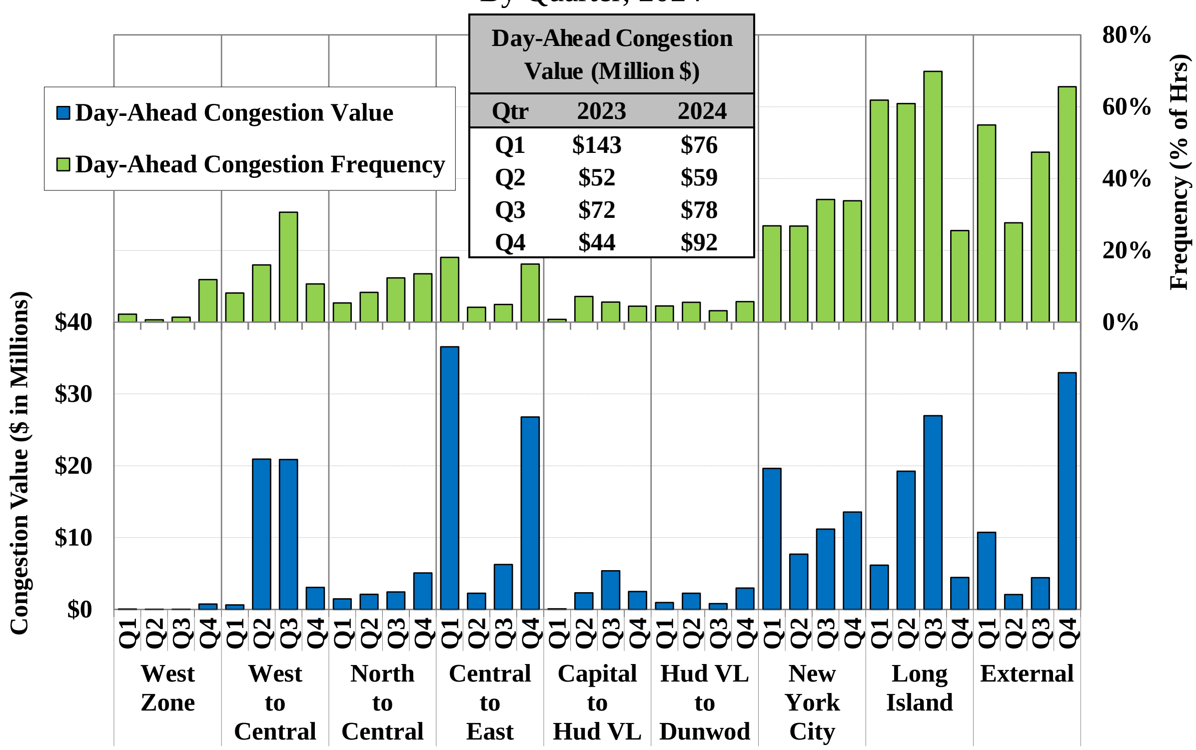
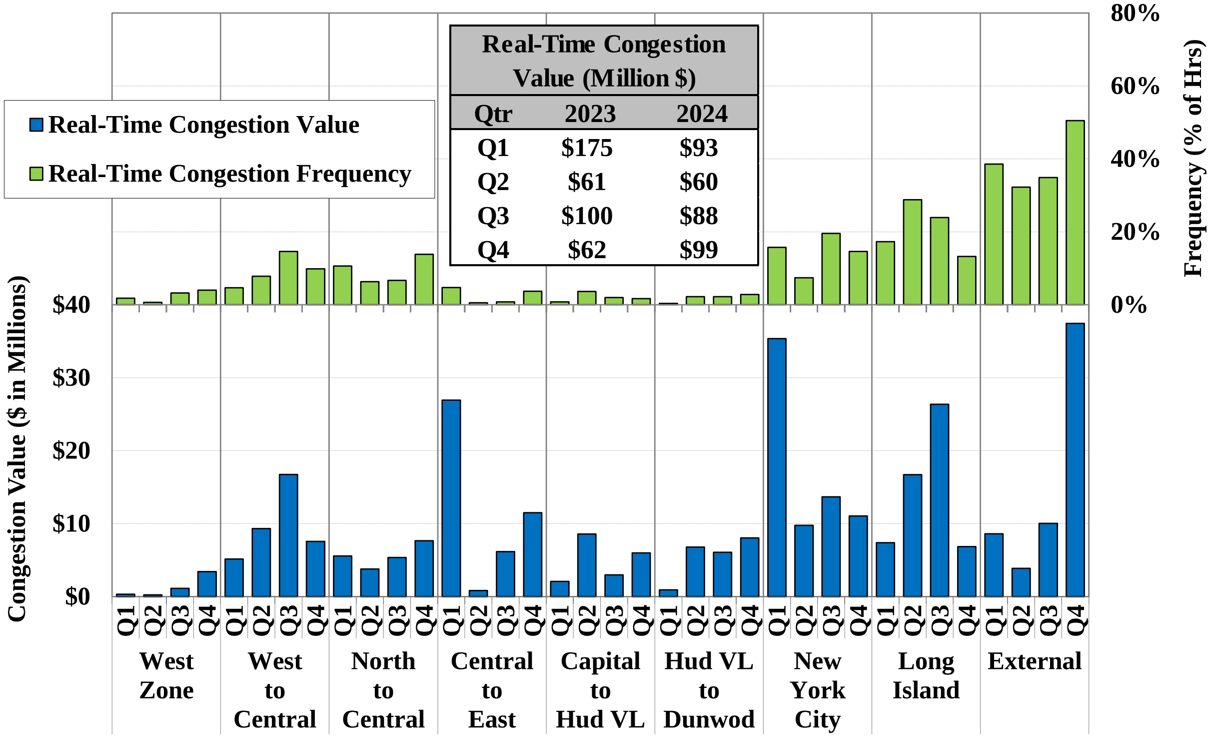


Figure A-42: Real-Time Congestion by Transmission Path
By Quarter, 2024



C. Real-Time Congestion Map by Generator Location

Figure A-43 to Figure A-44: Real-Time Load-Weighted Congestion Maps by Location

The previous subsection reports congestion patterns on a zonal basis or along large inter-zonal interfaces, while this subsection displays more granular information pertaining to congestion across generator nodes. Figure A-43 and Figure A-44 are two congestion maps showing such information for the entire system and New York City, respectively.

The maps display differences in LBMPs between generator nodes across the system,[243] illustrating transmission bottlenecks not only between broader areas but also within smaller subareas, highlighting the prevalence of intra-zonal price divergence between generation pockets and load pockets. Often, significant congestion arises from an abundance of inexpensive generation located in an export pocket driving bottlenecks on transmission lines servicing load pockets with a small number of competing generators. It also highlights where generation or transmission investment is likely to be most valuable, which can help guide investment. Each map shows details of nodal congestion in the real-time market in 2024, specifically:

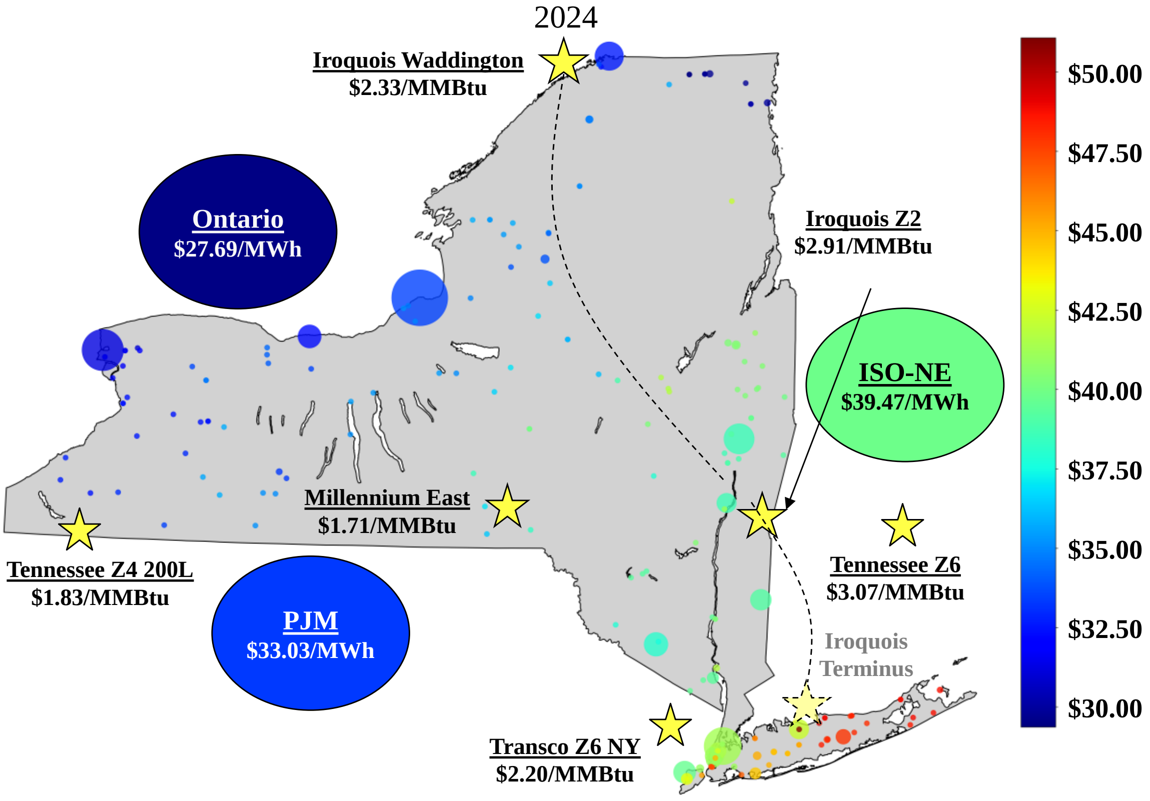
- Load-weighted hourly average real-time LBMP at each generator node within the region;

243 Although the differences in LBMPs include the differences in congestion and losses, the differences in losses are usually much smaller than the differences in congestion, particularly between generator nodes that are within smaller subareas.

- For the systemwide map, real-time prices on the neighboring area's side of the external interface are load-weighted using NYCA systemwide load and presented as additional bubbles. These bubbles are not sized based on average generation levels;[244] and
- Pertinent gas market information including regional gas prices in the systemwide map and key operational points of gas delivery in the NYC map.[245]

The generator bubbles are sized based on annual average generation MWh, however the sizing of these bubbles differs between the two maps due to the disparities in geographical sizes of the entire system versus New York City. In each case, however, a floor value is set such that generators at or below a certain annual average output all appear with the same size (i.e., the smallest sized bubble on the map), while generators with greater annual average outputs are shown with a size that is in proportion to their annual average generation. Portfolios with multiple generator PTIDs at the same station or within close proximity to each other are aggregated into one bubble and sized based on average portfolio generation. Each generator bubble is colored based on a heat mapping scale included to the right of each map. Prices along the color-scale are included with colder colors representing lower load-weighted real-time prices.

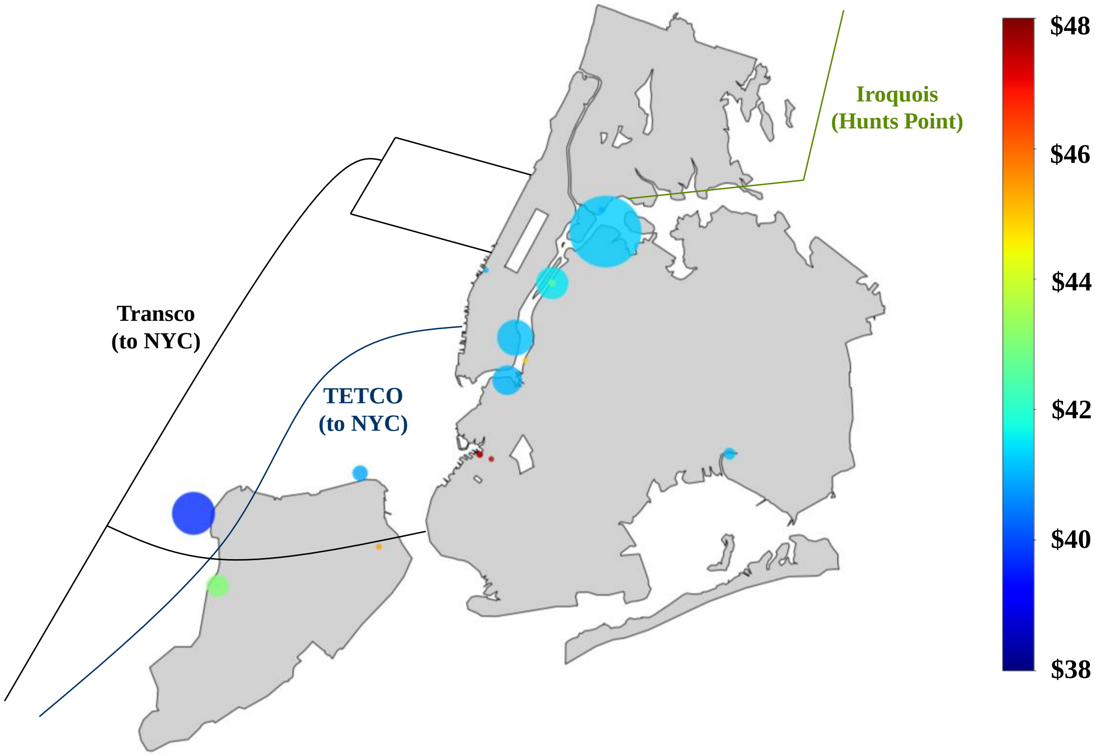
Figure A-43: NYCA Real-Time Load-Weighted Generator Congestion Map



244 The external interface prices are sourced from the respective system operator web platforms for each region. These prices can be found for each region at PJM, ISO-NE, and IESO web platforms.

245 Natural gas prices are based on the average index prices without additional adders sourced from Platts.

Figure A-44: NYC Real-Time Load-Weighted Generator Congestion Map
2024



D. Transmission Constraints Managed with OOM Actions

Transmission constraints on the high-voltage network (including 230 and 345 kV facilities in upstate New York and most 138 kV facilities in New York City and Long Island) are generally managed through the day-ahead and real-time market systems. This provides several benefits including: (a) that the market optimization balances the costs of satisfying demand, ancillary services, and transmission security requirements, resulting in more efficient scheduling decisions; and (b) that the market optimization also produces a set of transparent clearing prices, which provide efficient signals for longer lead time decisions such as fuel procurement, generator commitment, external transaction scheduling, and investment in new and existing resources and transmission.

However, transmission constraints on the low-voltage (i.e., 115 kV and lower) network were usually managed with out-of-market operator actions until 2015 when the NYISO started to incorporate these low-voltage constraints into the market systems. The typical operator actions to resolve constraints on the low-voltage network include:

- Out of merit dispatch and supplemental commitment of generation;
- Curtailment of external transactions and limitations on external interface transfer limits;
- Use of an internal interface/constraint transfer limit that functions as a proxy for the limiting transmission facility; and

- Adjusting PAR-controlled line flows on the high voltage network.[246]

In this subsection, we evaluate:

- The frequency of such OOM actions used to manage transmission constraints on the low voltage network in New York (including 115 kV and 69 kV facilities) that are not incorporated in the market systems; and
- The potential pricing impact in several load pockets on Long Island.

Figure A-45 & Figure A-46: OOM-Managed Constraints on the Low Voltage Network

Figure A-45 shows the number of days in 2024 when various resources were used out of merit to manage constraints in six areas of New York: (a) West Zone; (b) Central & Genesee Zones; (c) Capital Zone; (d) North & Mohawk Valley Zones; (e) Hudson Valley Zone; and (f) Long Island. In addition, the figure also reports the number of days when out-of-merit commitments were made to satisfy voltage needs or N-1-1 reserve needs in several local load pockets.

Figure A-45: OOM-Managed Constraints in New York
Summary of Resources Used to Manage Constraints, 2024

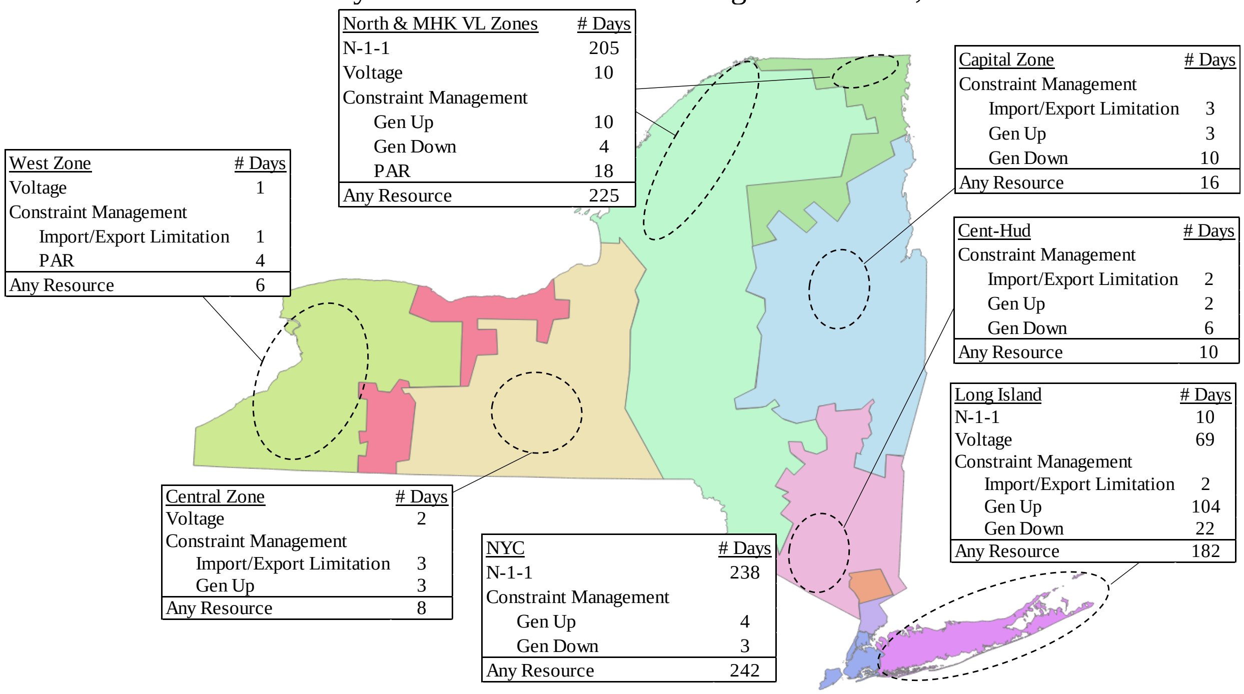


Figure A-46 focuses on the area of Long Island, showing the number of hours and days in 2024 when various resources were used to manage 69 kV (labeled as "69 kV OOM") and TVR constraints (labeled as "TVR OOM") in four load pockets of Long Island:

- Valley Stream: Mostly constraints around the Valley Stream bus;

246 These constraints are sometimes managed with the use of line switching on the distribution system, but this is not included in our analysis here.

- Brentwood: Mostly constraints around the Brentwood bus;
- East of Northport: Mostly the Central Islip-Hauppauge and the Elwood-Deposit circuits;
- East End: Mostly the constraints around the Riverhead bus and the TVR requirement.

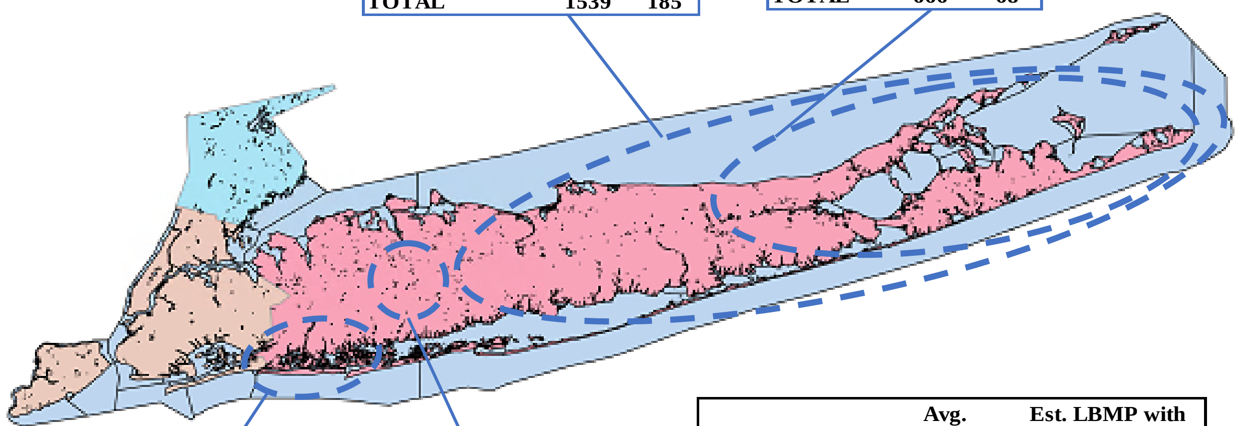
For a comparison, the tables also show the frequency of congestion management on the 69 kV and 138 kV constraints via the market model. Figure A-46 also shows our estimated price impacts in each Long Island load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.[247]

Figure A-46: Constraints on the Low Voltage Network on Long Island

Frequency of Action Used to Manage Constraints, 2024

East of Northport	#Hours	#Days
69kV OOM	82	9
69kV	1427	177
138kV	603	90
TOTAL	1539	185

East End	#Hours	#Days
69kV OOM	20	5
TVR OOM	646	63
TOTAL	666	68



Valley Stream	#Hours	#Days
69kV OOM	371	49
138kV	1324	225
TOTAL	1621	244

Brentwood	#Hours	#Days
69kV OOM	5	2
69kV	153	53
TOTAL	157	54

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$41.41	$41.43
East End	$44.04	$57.92
East of Northport	$43.27	$43.44
Valley Stream	$41.30	$42.58

E. Linear Constraints to Model Long Island East End TVR Requirements

Certain resources are required to be online to satisfy the Transient Voltage Recovery ("TVR") requirement on the East End of Long Island.[248] These resources are expensive oil peakers, which are rarely committed economically. As a result, OOM commitments are made by the local TO based on operating guidelines.[249] These OOM commitments not only generate uplift but also depress real time prices on Long Island (see Figure A-46). Integrating TVR requirements into

247 The following generator locations are chosen to represent each load pocket: (a) Barrett ST for the Valley Stream pocket; (b) NYPA Brentwood GT for the Brentwood pocket; (c) Holtsville IC for the East of Northport pocket; and (d) Green Port GT for the East End pocket.

248 Includes Global Greenport GT, East Hampton units, South Hampton IC, and Southold IC.

249 See *East End Operating Guideline*, available at: https://www.psegliny.com/oasis/transmission-owner-information-being-released-to-market.

the market software could enable more efficient scheduling and pricing of resources on Long Island. This subsection outlines an approach to modeling TVR requirements using linear constraints for scheduling and pricing purposes.

The following three tables, excerpted from the latest *East End Operating Guideline*, detail operating options under various outage conditions and load levels.[250] Table A-1 summarizes generator start procedures for 20 operating scenarios based on the availability of two voltage-control devices: the 9EU DVAR and the 9C DRSS. Depending on their statuses, either Table A-2 or Table A-3 is utilized to guide the commitments of the five oil-fired peakers on the East End.

For instance, in Scenario 1, where both voltage-control devices are fully available, oil peakers must be committed to address the TVR need when South Fork load exceeds 173 MW. In such cases, the "*Equivalent Unit Support for South Fork Load to Resolve TVR"* values from Table A-3 serve as a reference for resource commitment.

Table A-1: East End Generation Start Procedures

	9EU DVAR	9C DRSS DVAR	9C DRSS CAPS	GEN START	ARM VOLTAGE COLLAPSE	Generator Equivalent table
1	Available	100%	Available	173	294	Table 2
2	Available	75%	Available	172	281	Table 1
3	Available	50%	Available	171	280	
4	Available	25%	Available	170	279	
5	Available	0%	Unavailable	169	278	
6	Available	100%	Unavailable	171	280	Table 1
7	Available	75%	Unavailable	170	279	Table 1
8	Available	50%	Unavailable	170	279	
9	Available	25%	Unavailable	169	278	
10	Available	0%	Unavailable	169	278	
11	Unavailable	100%	Available	155	276	Table 2
12	Unavailable	75%	Available	154	263	Table 1
13	Unavailable	50%	Available	153	262	
14	Unavailable	25%	Available	152	261	
15	Unavailable	0%	Unavailable	151	260	
16	Unavailable	100%	Unavailable	153	262	Table 1
17	Unavailable	75%	Unavailable	152	261	Table 1
18	Unavailable	50%	Unavailable	152	261	
19	Unavailable	25%	Unavailable	151	260	
20	Unavailable	0%	Unavailable	151	260	

250 See the *East End Operating Guideline, released on 07/22/2022*.

Table A-2: East End Generator Support (Table 1)
Canal DRSS not Fully Available

Units	Equivalent unit support for South Fork load to resolve TVR*
Greenport GT	34 MW
East Hampton GT	24 MW
East Hampton Diesel	10 MW
Southold GT	20 MW
Southampton GT	13 MW**
Total Unit Support	101 MW

* There is an additional 8 MW of support for first unit dispatched due to change in limiting condition (i.e. if Greenport GT is dispatched first, the unit will provide 34+8=42 MW of support)
** Southampton GT cannot be dispatched first

Table A-3: East End Generator Support (Table 2)
Canal DRSS 100% Available

Units	Equivalent unit support for South Fork load to resolve TVR
Greenport GT	46 MW
East Hampton GT	37 MW
East Hampton Diesel	16 MW
Southold GT	22 MW
Southampton GT	0 MW*
Total Unit Support	121 MW

* Southampton GT does not provide support for TVR. Unit can be dispatched for load and/or thermal constraints.

The following linear constraints can be developed to represent Table A-2 and Table A-3. As shown in Table A-4, the dispatch levels of the five generators are labeled G1 through G5, while their commitment statuses are denoted as C1 through C5. For pricing purposes, all five blocked-on resources can be dispatched flexibly between zero and their respective UOLs.

Table A-4: East End Generator Commitment and Dispatch Parameters

Resource Name	Generator Dispatch [0, UOL]	Commitment Status {0, 1}	Bid UOL
Greenport GT	G1	C1	UOL1
East Hampton GT	G2	C2	UOL2
East Hampton Diesel	G4	C3	UOL3
Southold GT	G3	C4	UOL4
South Hampton GT	G5	C5	UOL5

Table A-3 is straightforward to model with the following two linear constraints:

- For commitment,

  $46 * C1 + 37 * C2 + 16 * C3 + 22 * C4 + 0 * C5 \geq South\ Fork\ Load - Load\ Trigger$, where C1 to C5 are binary commitment variables (0 or 1).
- For pricing,

  $\frac{46}{UOL1} G1 + \frac{37}{UOL2} G2 + \frac{16}{UOL3} G3 + \frac{22}{UOL4} G4 + \frac{0}{UOL5} G5 \geq South\ Fork\ Load - Load\ Trigger$, where G1 to G5 are dispatchable from 0 to their individual UOL.

Table A-2 has additional constraints, thus it is segmented to account for the additional 8 MW of support from the first committed resource.

Case 1: When $0 \leq South\ Fork\ Load - Load\ Trigger \leq 8$,

- For commitment,

  $34 * C1 + 24 * C2 + 10 * C3 + 20 * C4 + 13 * C5 \geq South\ Fork\ Load - Load\ Trigger$
- For pricing,

  $\frac{34}{UOL1} G1 + \frac{24}{UOL2} G2 + \frac{10}{UOL3} G3 + \frac{20}{UOL4} G4 + \frac{13}{UOL5} G5 \geq South\ Fork\ Load - Load\ Trigger$.

Case 2: When $South\ Fork\ Load - Load\ Trigger > 8$,

- For commitment,

  $34 * C1 + 24 * C2 + 10 * C3 + 20 * C4 + 13 * C5 \geq South\ Fork\ Load - Load\ Trigger - 8$
- For pricing,

  $\frac{34}{UOL1} G1 + \frac{24}{UOL2} G2 + \frac{10}{UOL3} G3 + \frac{20}{UOL4} G4 + \frac{13}{UOL5} G5 \geq South\ Fork\ Load - Load\ Trigger - 8$

Additionally, to ensure that South Hampton GT is not dispatched first, the following constraint must be enforced:

- $C5 \leq C1 + C2 + C3 + C4$

These linear constraints could provide a mechanism to efficiently schedule and price the TVR requirement through the market software rather than inefficient OOM actions and uplift payments.

F. Day-Ahead and Balancing Congestion Shortfalls by Path or Constraint

Congestion shortfalls generally occur because of inconsistent modeling of the transmission system between markets. Day-ahead congestion shortfalls indicate inconsistencies between the TCC and day-ahead market, while balancing congestion shortfalls indicate inconsistencies between the day-ahead market and the real-time market. These two classes of shortfalls are evaluated in this subsection.

Figure A-47: Day-Ahead Congestion Revenue Shortfalls

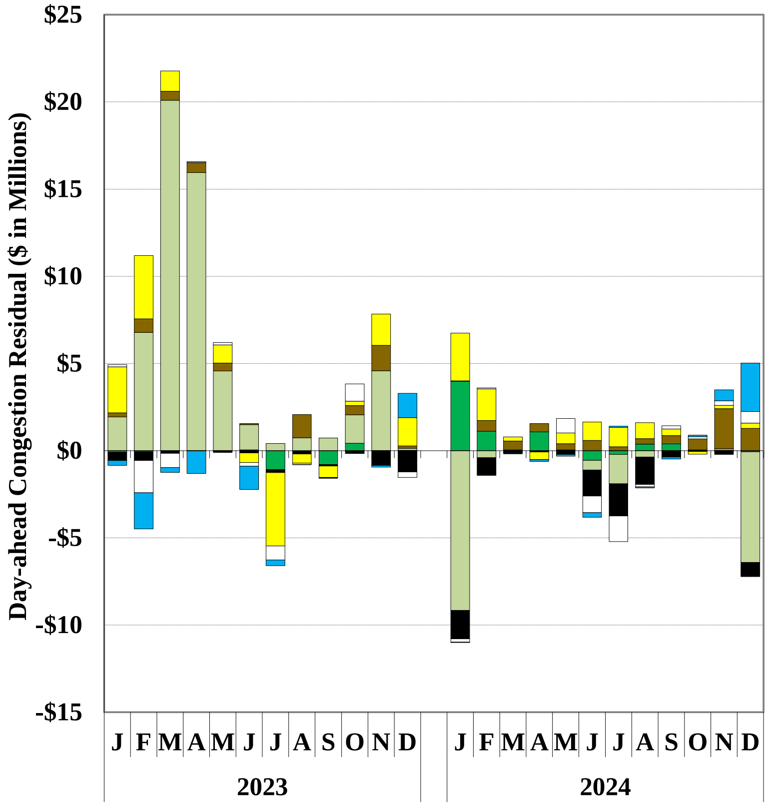
Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion. Similarly, surpluses occur when the quantity of TCCs sold for a path is less than the transfer capability of the path in the day-ahead market during periods of congestion. The NYISO minimizes day-ahead congestion revenue surpluses and shortfalls by offering TCCs in the forward auction that reflect the expected transfer capability of the system. In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantities of TCCs that are offered by NYISO.

NYISO determines the quantities of TCCs to offer in a TCC auction by modeling the transmission system to ensure that the TCCs sold are simultaneously feasible. NYISO uses a power flow model that includes an assumed configuration of the transmission system. The simultaneous feasibility condition requires that the TCCs awarded be feasible in a contingency constrained economic dispatch of the NYISO transmission system. If this condition is satisfied, the congestion revenues collected are expected to be sufficient to fully fund awarded TCCs. However, if transmission outages occur that were not modeled in the TCC auction or the assumptions used in the TCC auctions (e.g., assumptions related to PAR schedules and loop flows) are inconsistent with the assumptions used in the day-ahead market, the congestion revenues collected may be insufficient to meet TCC obligations.

Figure A-47 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2023 and 2024. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- North to Central: Transmission lines in the North Zone, the Moses-South Interface, EDIC-Marcy 345 line, and Marcy 765-Marcy 345 line.
- Central to East: Primarily the Central-East interface.
- New York City Lines: Lines leading into and within New York City.
- Long Island Lines: Lines leading into and within Long Island.
- External: Related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

Figure A-47: Day-Ahead Congestion Shortfalls
2023 – 2024



	Category	Annual Shortfall ($M)	
		2023	**2024**
	Central to East	**$58.9**	**-$18.4**
	North to Central	**$6.0**	**$7.8**
	Long Island Lines		
	901/903 PARs	**-$3.9**	**-$9.4**
	Other Factors	**$6.2**	**$8.7**
	New York City Lines	**-$1.6**	**$6.2**
	External	**-$4.3**	**$2.9**
	All Other Facilities	**-$2.8**	**-$0.7**

The figure also shows the shortfalls resulting from some unique factors separately from other reasons for select transmission paths. For Long Island lines, the figure shows separately the shortfalls resulted from differences in assumed schedules across the two PAR controlled lines between Lake Success and Valley Stream in Long Island and Jamaica in New York City (i.e., 901/903 lines) between the TCC auction and the day-ahead market, labeled as "901/903 PARs" in the figure.

Figure A-48: Balancing Congestion Revenue Shortfalls

Balancing congestion revenue shortfalls occur when day-ahead scheduled flows across a particular line or interface exceed its real-time transfer capability, which often requires the ISO to redispatch in real time by purchasing additional generation in the import-constrained area (where real-time prices are high) and selling back energy in the export-constrained area (where real-time prices are low). The cost of this redispatch is the balancing congestion shortfall.

Key factors causing changes in transfer capability between day-ahead and real-time markets include:

- **Transmission Deratings and Outages** – When these occur after the day-ahead market, they reduce the transfer capability of relevant transmission interfaces or facilities. They may also change the size of the largest contingency relative to a particular transmission interface or the distribution of flows over the transmission system, thereby reducing the available transfer capability of other transmission facilities.

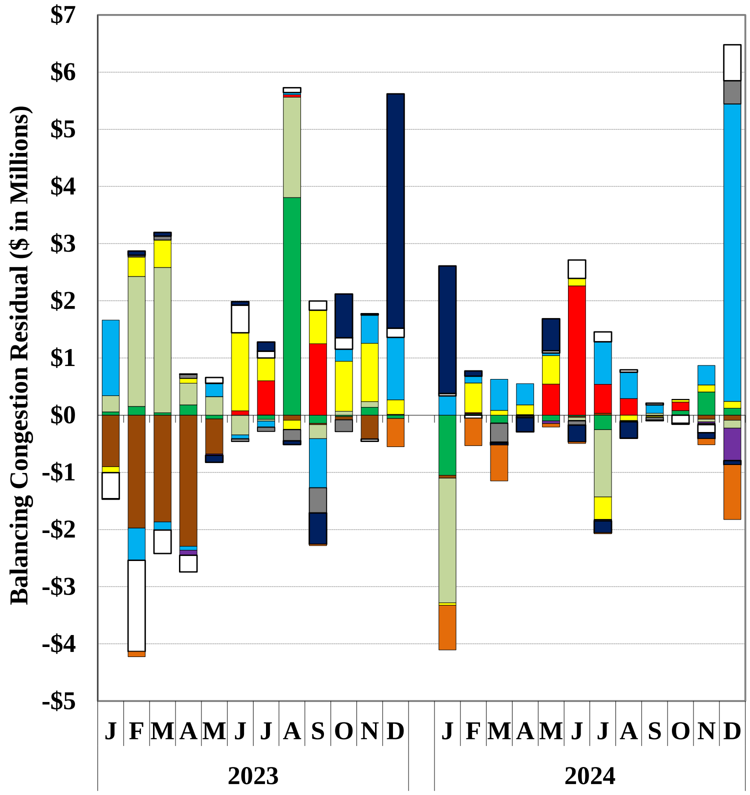
- **Unmodeled Constraints in the Day-ahead Market** – Reliability rules require the NYISO to reduce actual flows across certain key interfaces during TSA events. Since TSA events are not modeled in the day-ahead market, they generally result in reduced transfer capability between the day-ahead market and real-time operation. The imposition of simplified interface constraints in New York City load pockets in the real-time market that are not modeled comparably in the day-ahead market also results in reduced transfer capability between the day-ahead market and real-time operation.
- **Fast-Start Pricing** – This methodology treats physically inflexible gas turbines as flexible in the pricing logic of the real-time market model. Differences between the physical dispatch logic and the pricing logic can lead to unutilized transfer capability on interfaces that are congested in real time, leading to balancing congestion revenue shortfalls.
- **PAR Controlled Line Flows** – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled lines that result from the Coordinated Congestion Management ("M2M") process between NYISO and PJM.
- **Unscheduled Loop Flows** – loop flows from other regions use a portion of the transmission capability across many interfaces in New York, reducing the portion of transmission capability available to the NYISO market in the direction of the loop flows. A balancing congestion revenue shortfall occurs when the loop flows assumed in the day-ahead market are lower than the actual loop flows on congested interfaces in real time.

The net cost of the redispatch in real-time due to changes from day-ahead (i.e., balancing congestion shortfalls) is collected from loads through uplift charges, most of which is allocated to load throughout the state. However, a portion associated with facilities that require special operation during TSA events is charged to Consolidated Edison whose customers benefit most directly from the additional reliability.

Similar to Figure A-47, Figure A-48 shows balancing congestion shortfalls by transmission path or facility in each month of 2023 and 2024. For select transmission paths, the figure also shows the shortfalls resulted from some unique factors separately from other reasons. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-48: Balancing Congestion Shortfalls[251]

In $Millions, 2023 – 2024



Category	Annual Shortfall ($M) 2023	2024
External	$1.6	$8.3
TSA Constraints	$2.0	$3.8
N.Y.C.	$4.5	$1.6
Long Island Lines	$5.1	$1.1
North to Central	$4.0	-$0.9
Capital to Hud VL		
Ramapo, A & JK PARs	-$0.1	-$0.6
Other Factors	-$0.8	-$0.1
Central to East		
Ramapo, A & JK PARs	-$8.2	-$0.2
Other Factors	$7.1	-$3.6
M2M Entitlement	-$0.6	-$3.1
All Other Facilities	-$1.5	$0.9

G. Transmission Line Ratings

Transmission line ratings define the maximum transfer capability of each line, impacting commitment. dispatch, congestion and prices. Accurate line ratings are essential - understated ratings can lead to inefficient market outcomes (e.g., higher production costs, and unnecessarily high congestion and energy prices), while overstated ratings may pose reliability risks.

Line ratings are typically limited by thermal, voltage, or stability constraints, with thermal limits usually being the most restrictive. Thermal limits are typically influenced by ambient conditions (e.g., temperature, wind speed, and solar irradiance). For example, when ambient temperatures are cooler than the typical assumptions used for rating the facilities, additional power flows can be accommodated.

Currently, the NYISO primarily uses static seasonal line ratings for most facilities in the day-ahead and real-time markets. Some Ambient Adjusted Ratings ("AARs") are applied in the real-time market, but static line ratings remain prevalent. This subsection examines the potential economic benefits of implementing hourly AARs in NYISO's markets.

251 The balancing congestion shortfalls estimated in this figure may differ from actual balancing congestion shortfalls because the figure: (a) is partly based on real-time schedules rather than metered injections and withdrawals; and (b) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of any ex-post price corrections.

Figure A-49: Potential Congestion Benefit of Using Ambient-Temperature Adjusted Ratings

Figure A-49 shows our estimate of potential congestion benefit from using ambient-temperature adjusted line ratings for 2019 to 2024.

We estimate ambient-adjusted ratings based on the following assumptions: [252]

- Summer line ratings are developed based on an ambient temperature of 95°F (or 35°C);
- Winter line ratings are developed based on an ambient temperature of 50°F (or 10°C); and
- For overhead lines, the relationship between the ambient-adjustment rating factor and the ambient temperature is close to linear in a wide range of normal weather conditions.

Therefore, we extrapolate the ambient adjusted ratings from the straight line that connects the summer and winter ratings and their assumed rating temperatures.[253] Wind speed is a critical parameter that impacts equipment thermal ratings, but its variation is not considered in this calculation.

In the figure, the bars in the bottom of the chart represent the estimated potential benefit, which equals the constraint shadow cost times the additional transfer capability from the estimated potential ambient adjustment.[254] These estimates are done separately for the day-ahead and real-time markets on an hourly basis. This is shown separately for facilities: a) in the West Zone; b) from West to Central; c) from North to Central; d) from Capital to Hudson Valley; and e) from Hudson Valley to Dunwoodie. The bars in the top portion of the chart show the potential benefit as a percent of total congestion values in each facility group. The inset table summarizes these quantities on an annual basis for all facilities combined.

The Central-East interface is not included in this analysis because its rating is based on the voltage collapse limit, which is not typically affected by ambient temperature. The transmission facilities in New York City and Long Island are also excluded because most of these facilities are underground cables, whose ratings are not as sensitive to ambient air temperature as overhead lines.

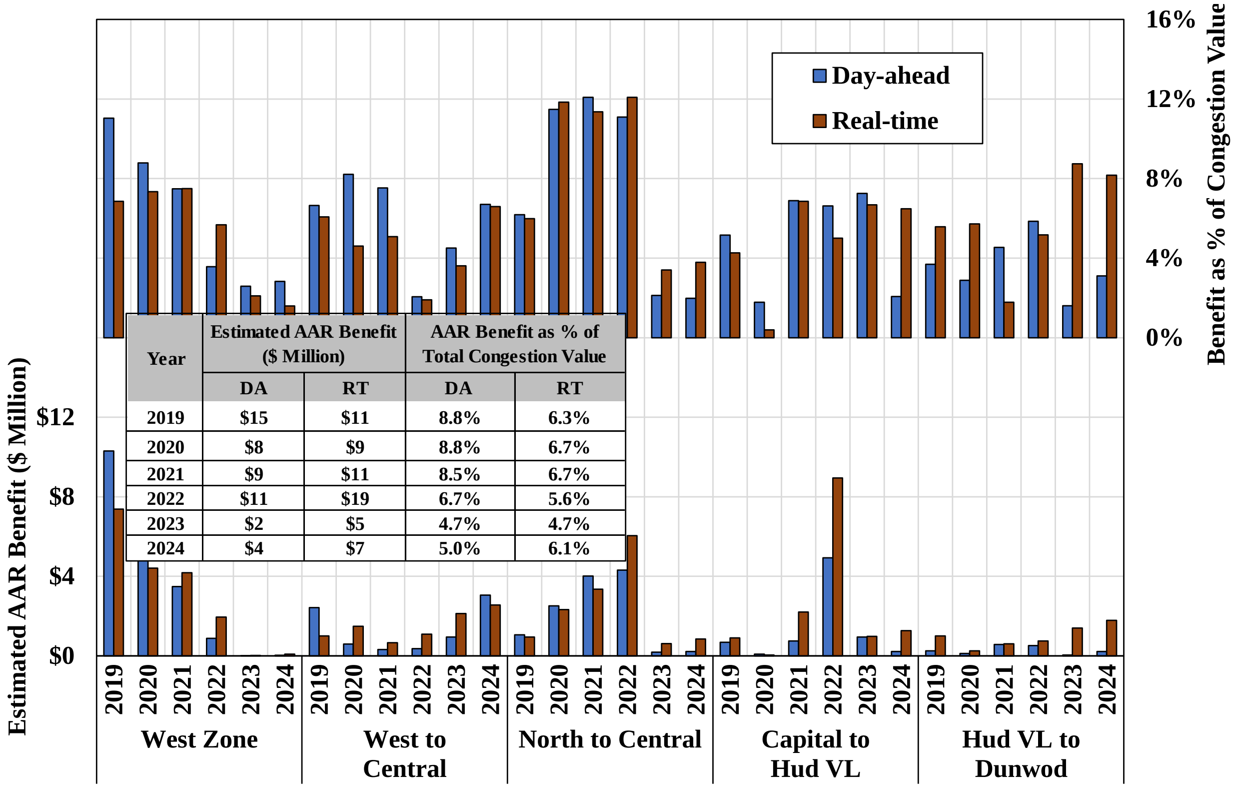
252 See "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" by New York Power Pool, 1995.

253 For example, if the line rating for a facility is 100 MW in the summer and 145 MW in the winter, then the ambient adjusted rating at 80°F is calculated as 100 + (80-95)*(145-100)/(50-95) = 115 MW.

254 For example, if NYISO uses a rating of 120 MW for one transmission facility in the market model, the facility is binding with a shadow cost of $100/MWh, and our estimated ambient adjusted rating is 150 MW, then the potential congestion benefit is estimated as (150-120)*100 = $3000.

Figure A-49: Potential Congestion Benefit of Using AAR Line Ratings

2019-2024



Year	Estimated AAR Benefit ($ Million)		AAR Benefit as % of Total Congestion Value	
	DA	RT	DA	RT
2019	$15	$11	8.8%	6.3%
2020	$8	$9	8.8%	6.7%
2021	$9	$11	8.5%	6.7%
2022	$11	$19	6.7%	5.6%
2023	$2	$5	4.7%	4.7%
2024	$4	$7	5.0%	6.1%

H. TCC Prices and DAM Congestion

In this subsection, we evaluate whether clearing prices in the TCC auctions were consistent with congestion prices in the day-ahead market. TCCs provide an entitlement to the holder for the day-ahead congestion between two points. In a well-functioning market, the price for the TCC should reflect a reasonable expectation of the day-ahead congestion. Perfect convergence cannot be expected because many factors affecting congestion are not known at the time of the auctions, including forced outages of generators and transmission, fuel prices, weather, etc. There are two types of TCC auctions: Centralized TCC Auctions and Reconfiguration Auctions.

- *Centralized TCC Auctions* – TCCs are sold in these auctions as 6-month products for the Summer Capability Period (May to October) or the Winter Capability Period (November to April), as 1-year products for two consecutive Capability Periods, and as 2-year products for four consecutive Capability Periods. Most transmission capability is auctioned as 6-month products. The Capability Period auctions consist of a series of rounds, in which a portion of the capability is offered, resulting in multiple TCC awards and clearing prices. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in these auctions.

- *Balance-of-Period Auctions* [255] – The NYISO conducts a Balance-of-Period Auction once every month for the remaining months in the same Capability Period for which the TCC will be effective. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Balance-of-Period Auction. Each monthly Balance-of-Period Auction consists of only one round.

Figure A-50: TCC Cost and Profit by Auction Round and Path Type

Figure A-50 summarizes TCC cost and profit for the Winter 2023/24 and Summer 2024 Capability Periods (i.e., the 12-month period from November 2023 through October 2024). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

The figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) three rounds of one-year auctions for the exact same 12-month Capability Period; (b) four rounds of six-month auctions for the Winter 2023/24 Capability Period; (c) four rounds of six-month auctions for the Summer 2024 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[256] The figure includes the TCCs that were purchased and sold by Market Participants in these auctions.

For the purposes of the figure, each TCC is broken into inter-zonal and intra-zonal components, making it possible to identify portions of the transmission system that generate the most revenue in the TCC auction and that are most profitable for the buyers of TCCs. Each TCC has a Point-Of-Injection ("POI") and a Point-Of-Withdrawal ("POW"). The POI and POW may be a generator bus, a NYCA Zone, the NYISO Reference Bus, or an external proxy bus. For the purpose of this analysis, all transacted TCCs in the auctions are unbundled into the following standard components: (a) POI to the Zone containing the POI (POI Zone), (b) POI Zone to the Zone containing the POW (POW Zone), and (c) POW Zone to POW. When a TCC is unbundled into standard components for this analysis, the original TCC is replaced by up to three TCCs. The three standard components are further grouped into two categories: (a) inter-zone TCCs, which include all unbundled POI Zone to POW Zone TCCs; and (b) intra-zone TCCs, which include POI to POI Zone TCCs and POW Zone to POW TCCs.[257]

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255 The Balance-of-Period Auction started with the September 2017 monthly auction, which replaced the previous Reconfiguration Auction that was conducted only for the next one-month period.

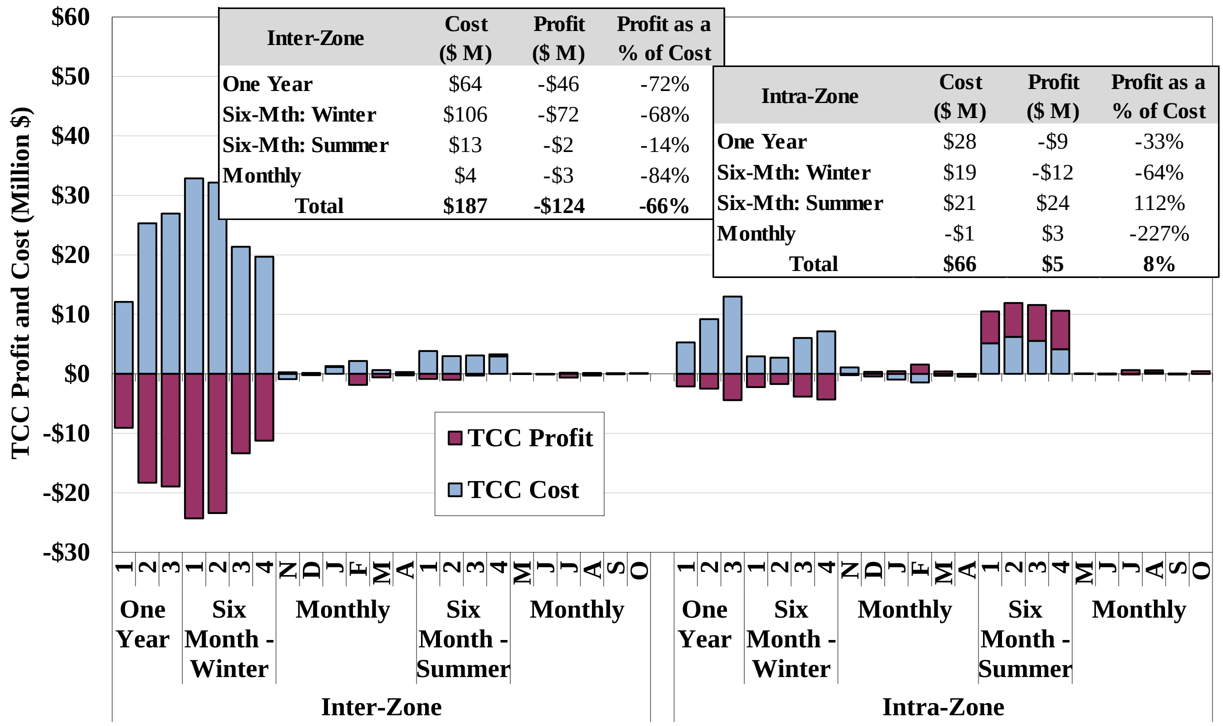
256 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

257 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 is unbundled to three components: (a) A 100 MW TCC from Indian Point 2 to Millwood Zone; (b) A 100 MW TCC from Millwood Zone to New York City Zone; and (c) A 100 MW TCC from New York City Zone to Arthur Kill 2. Components (a) and (c) belong to the intra-zone category and Component (b) belongs to inter-zone category.

The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs. The table in the figure summarizes the TCC cost, profit, and profitability for each type of TCC auction for the two categories of TCC paths. The profitability is measured by the total TCC profit as a percentage of total TCC cost.

Figure A-50: TCC Cost and Profit by Auction Round and Path Type

Winter 2023/24 and Summer 2024 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$64	-$46	-72%
Six-Mth: Winter	$106	-$72	-68%
Six-Mth: Summer	$13	-$2	-14%
Monthly	$4	-$3	-84%
Total	**$187**	**-$124**	**-66%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$28	-$9	-33%
Six-Mth: Winter	$19	-$12	-64%
Six-Mth: Summer	$21	$24	112%
Monthly	-$1	$3	-227%
Total	**$66**	**$5**	**8%**

Table A-5 & Table A-6: TCC Cost and Profit by Path

The following two tables compare TCC costs with TCC profits for both intra-zonal paths and inter-zonal paths during the Winter 2023/24 and Summer 2024 Capability Periods (i.e., the 12-month period from November 2023 through October 2024). Each pair of POI and POW represents all paths sourcing from the POI and sinking at the POW. Inter-zonal paths are represented by pairs with different POI and POW, while intra-zonal paths are represented by pairs with the same POI and POW. TCC costs and profits that are higher than $2 million are highlighted with green, while TCC costs and profits that are lower than -$2 million are highlighted with light red.

Table A-5: TCC Cost by Path
Winter 2023/24 and Summer 2024 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$0	$0	$3	$0	$0	$0	$25	$0	$0	$0	$0	$0	$0	$0	$0	**$28**
GENESE	$0	$1	$1	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$1**
CENTRL	-$3	-$3	$37	$1	$0	$0	$9	$0	$0	$0	$0	$0	$0	$0	$0	**$41**
MHK VL	$0	-$1	$0	-$23	-$3	-$6	$0	$0	$0	$0	$0	$0	$0	$24	$0	**-$9**
NORTH	$1	$1	$1	$18	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$23**
CAPITL	$0	$0	-$8	-$2	$0	$25	-$20	-$1	-$3	$0	$3	$0	$0	-$1	$0	**-$8**
HUD VL	-$4	$0	-$5	-$1	$0	$9	$3	$4	$2	$20	$2	$0	$0	$55	-$1	**$84**
MILLWD	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$2	$0	$0	$0	$0	**$2**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$5	$0	$0	$0	$0	**$6**
N.Y.C.	$0	$0	$0	$0	$0	$0	-$1	$0	-$2	$12	$4	$0	$0	$0	$0	**$13**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0	$0	$0	$0	**$9**
O H	$1	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
H Q	$0	$0	$0	$19	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	**$20**
NPX	$0	$0	$0	$0	$0	-$2	-$4	$0	$0	$0	$0	$0	$0	$0	$0	**-$6**
PJM	-$10	$0	-$2	$0	$0	$0	$60	$0	$1	$0	$0	$0	$0	$0	$0	**$48**
Total	**-$15**	**-$2**	**$26**	**$13**	**-$2**	**$25**	**$71**	**$2**	**-$2**	**$33**	**$26**	**$1**	**$0**	**$78**	**-$1**	**$253**

Table A-6: TCC Profit by Path
Winter 2023/24 and Summer 2024 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$0	-$1	-$2	$0	$0	$0	-$19	$0	$0	$0	$0	$0	$0	$0	$0	**-$22**
GENESE	$0	-$1	-$1	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$1**
CENTRL	$2	$2	-$9	$0	$0	$0	-$7	$0	$0	$0	$0	$0	$0	$0	$0	**-$12**
MHK VL	$0	$1	$0	$19	$2	$5	$0	$0	$0	$0	$0	$0	$0	-$19	$0	**$7**
NORTH	$0	-$1	-$1	-$11	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$11**
CAPITL	$0	$0	$7	$1	$0	-$13	$14	$1	$2	$0	$0	$0	$0	$0	$0	**$13**
HUD VL	$3	$0	$4	$1	$0	-$7	-$3	-$2	-$1	-$9	-$1	$0	$0	-$40	$0	**-$55**
MILLWD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$1**
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	-$1	$0	$0	$0	$0	**$1**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0	$0	$0	$0	**$10**
O H	$1	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
H Q	$0	$0	$0	-$12	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	**-$13**
NPX	$0	$0	$0	$0	$0	$1	$3	$0	$0	$0	$0	$0	$0	$0	$0	**$4**
PJM	$8	$0	$2	$0	$0	$0	-$51	$0	-$1	$0	$0	$0	$0	$0	$0	**-$41**
Total	**$15**	**$1**	**$1**	**-$3**	**$4**	**-$14**	**-$63**	**-$1**	**$2**	**-$9**	**$8**	**-$1**	**$0**	**-$59**	**$0**	**-$118**

Figure A-51 - Figure A-53: Allocation of Day-ahead Congestion Residuals

Congestion shortfalls and surpluses resulting from differences between the TCC auctions and the day-ahead market are allocated to transmission owners as charges or credits. NYISO currently uses a two-stage process defined in the OATT for the allocations, as illustrated in Figure A-51:

- First, congestion residuals resulted from Qualifying facility changes (e.g., outages, return-to-services, and uprate/derate) are allocated to responsible transmission owners. This allocation is based on the flow impact of these change factors on the binding constraints in the day-ahead market, adhering to the cost causation principle. [258]
- Second, the remaining congestion residuals, referred to as *Net Congestion Rents*, are allocated to transmission owners in a different way. [259] These allocations are in

258 See OATT, Attachment N, Formula N-6 through N-14 for the calculation of these allocations.

259 See OATT, Attachment N, Formula N-15 for the calculation of these allocations.

proportion to the auction revenues from each TO's TCC holdings rather than day-ahead congestion patterns, which may not necessarily align with the cost causation principle.

Figure A-51: Illustration of Allocation of DAM Congestion Residuals

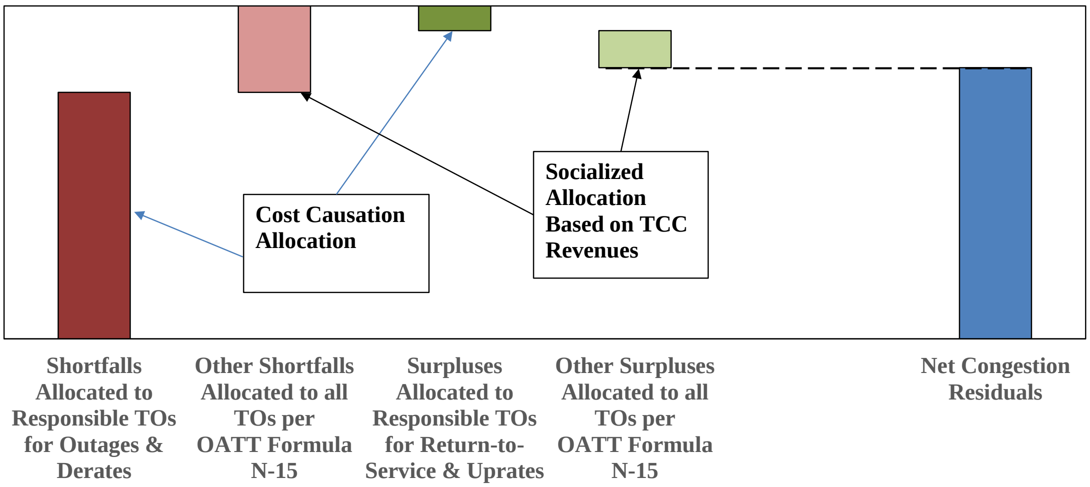
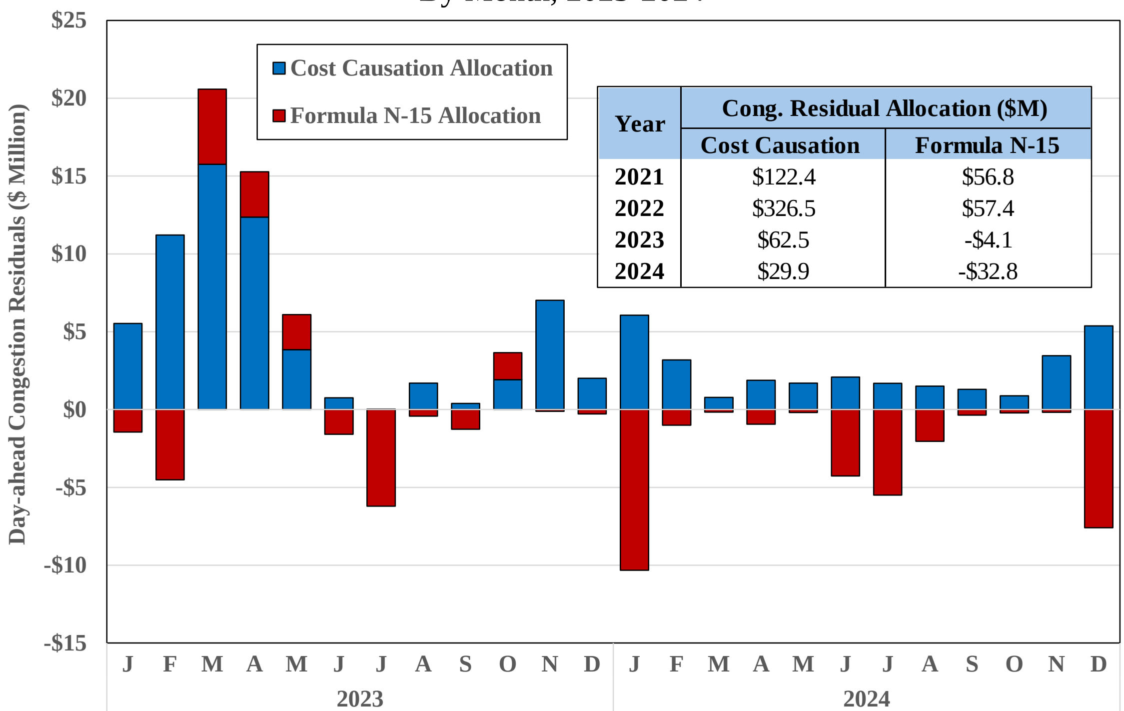


Figure A-52 shows actual allocations of day-ahead congestion residuals for each month over the past two years. The blue bars represent the portion allocated in the first stage based on a cost causation principle, while the red bars represent the portion that was allocated in the second stage based on TCC revenues using Formula N-15 in the OATT Attachment N. The inset table provides an annual summary of the net amount of congestion residuals allocated through these two methods for the past four years.

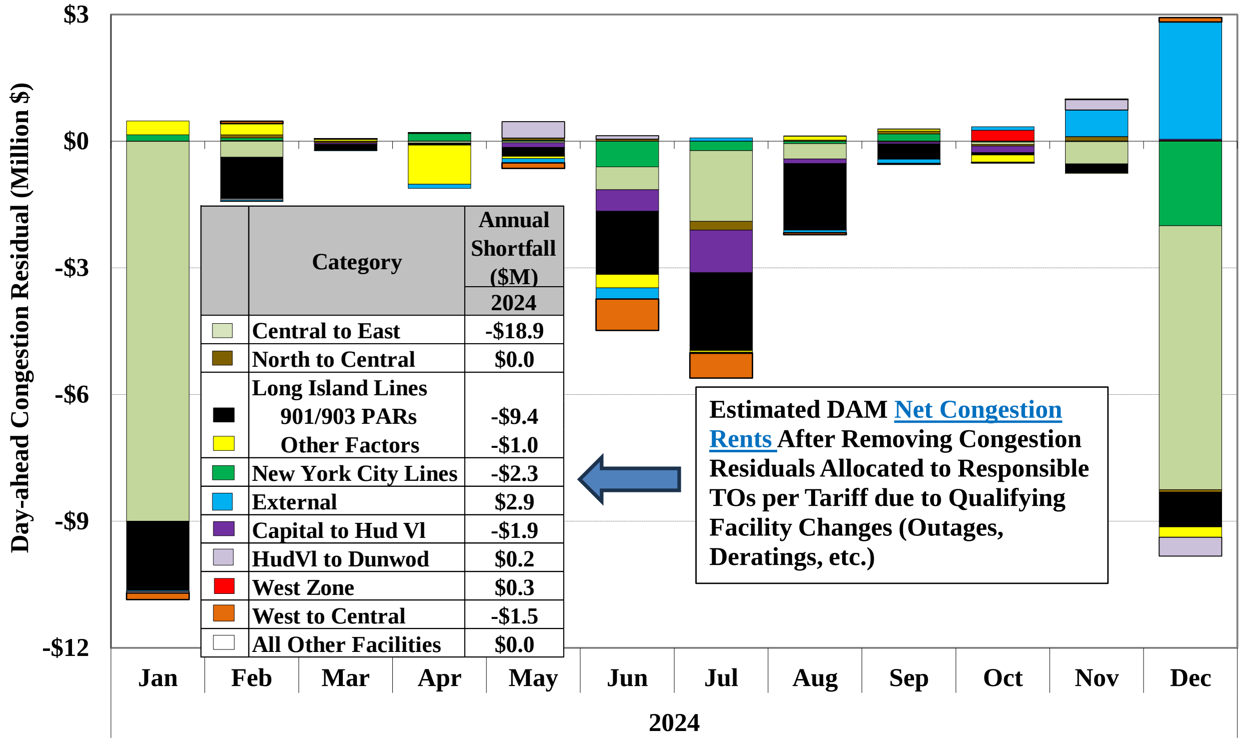
Figure A-52: Allocation of DAM Congestion Residuals
By Month, 2023-2024



Year	Cong. Residual Allocation ($M)	
	Cost Causation	Formula N-15
2021	$122.4	$56.8
2022	$326.5	$57.4
2023	$62.5	-$4.1
2024	$29.9	-$32.8

Figure A-53 shows our estimates of *Net Congestion Rents* related to particular transmission facility groups in each month of 2024.

Figure A-53: Estimated DAM Net Congestion Rents by Transmission Facility
2024



I. Potential Design of Financial Transmission Rights for PAR Operation

This subsection describes how a financial right could be created to compensate ConEd if the lines between NYC and Long Island were scheduled efficiently (rather than according to a fixed schedule) in accordance with Recommendation #2012-8, which is described in Section XII. An efficient financial right should compensate ConEd: (a) in accordance with the marginal production cost savings that result from efficient scheduling, and (b) in a manner that is revenue adequate such that the financial right should not result in any uplift for NYISO customers. Note, this new financial transmission right would not alter the TCCs possessed by any market party.

Concept for Financial Transmission Right

An efficient financial right should compensate ConEd for the quantity of congestion relief provided at a price that reflects the marginal cost of relieving congestion on each flow gate in the day-ahead and real-time markets. These are the same principles upon which generators are paid and load customers are charged. Hence, a transmission right holder should be paid:

DAM Payment =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}[-DAM\ SF_{l,c} \times DAM\ SP_c]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}[-RTM\ SF_{l,c} \times RTM\ SP_c]\right)$$

Total Payment = DAM Payment + RTM Payment, where a negative payment would result in a charge to ConEd. To illustrate, suppose there is congestion in the DAM on the interface from upstate to Long Island (Y50 Line), from upstate to NYC (Dunwoodie), and into the Valley Stream load pocket (262 Line) while the 901 Line flows are reduced below the contract amount:

- TCC MW_{901} = 96 MW
- DAM MW_{901} = 60 MW
- DAM SP_{Y50} = $10/MWh
- DAM $SP_{Dunwoodie}$ = $5/MWh
- DAM SP_{262} = $15/MWh
- DAM $SF_{901,\ Y50}$ = 100%
- DAM $SF_{901,\ Dunwoodie}$ = -100%
- DAM $SF_{901,\ 262}$ = 100%
- DAM $Payment_{901}$ = $720 per hour = (60 MW – 96 MW) x {(-100% x $10/MWh) + (100% x $5/MWh) + (-100% x $15/MWh)}

Since DAM payments are made for deviations from the TCC modeling assumptions, the new financial transmission right would not alter the TCCs possessed by any market party.

Revenue Adequacy

Just as the LBMP compensation to generators is generally revenue adequate, the new financial transmission right would also be revenue adequate. This is illustrated by the following scenarios:

- Basecase Scenario – Provides an example of the current market rules where the NYISO receives revenues from loads that exceed payments to generators, thereby contributing to DAM congestion revenues.
- PAR Relief Scenario – Shows how a PAR-controlled line could be used to reduce congestion, allowing the owner of the line to be compensated without increasing uplift from DAMCRs.
- PAR Loading Scenario – Shows how the owner of the line would be charged if the DAM schedule increased congestion relative to the TCC schedule assumption.

These scenarios use a simplified four node network, including: Upstate, NYC, Valley Stream, and Rest of Long Island. The four nodes are interconnected by four interfaces:

- The Dunwoodie interface from Upstate to NYC,
- The Y50 Line from Upstate to Rest of Long Island,
- The 262 Line from Rest of Long Island to Valley Stream, and

- The PAR-controlled 901 Line from Valley Stream to NYC.

For simplicity, the 901 Line contract amount that is used in the TCC auction is rounded to 100 MW.

The Base Case Scenario shows that a net of $22,500 of DAM congestion revenue is collected from scheduling by generators and loads. The table also shows the amount of DAM congestion revenue that accrues on each constrained facility. In this example, DAMCR equals $0 because the flows on each constrained facility are equal to the capability/assumption in the TCC model. Since the 901 Line contract moves power from a high LBMP area to a low LBMP area, it reduces congestion revenue by $2,000, but it does not cause DAMCR because it is consistent with the TCC auction.

The PAR Relief Scenario shows that if the 901 Line flow is reduced from 100 MW to 10 MW, it reduces the generation needed in Valley Stream and increases generation in NYC, reducing overall production costs by $1,800 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $1,800 of additional congestion revenues are collected. The collection of additional congestion revenues allows the NYISO to compensate ConEd $1,800 for the PAR adjustment, and DAMCR remains at $0.

The PAR Relief Scenario shows that if the 901 Line flow is increased from 100 MW to 120 MW, it increases the generation needed in Valley Stream and reduces generation in NYC, increasing overall production costs by $400 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $400 less congestion revenue is collected. The collection of less congestion revenue requires the NYISO to charge ConEd $400 for exceeding the contract amount, and DAMCR remains at $0.

BASECASE SCENARIO

	Node	**LBMP**	**Load**	**Generation**	**Load Revenue**	**Generator Payments**
Gen/Load Payments	Upstate	$25	10000	13000	$250,000	$325,000
	NYC	$30	4000	1900	$120,000	$57,000
	Valley Stream	$50	350	150	$17,500	$7,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,500
	Net (Gen minus Load)			0		$22,500

	Interface	**Shadow Price**	**Interface Flow**	**Congestion Revenue**
Transmission Revenue	Dunwoodie	$5	2000	$10,000
	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	Total			$22,500
	DAMCR (Gen minus Load minus Congestion)			$0

PAR RELIEF SCENARIO (901 Line Flow Reduced from 100 MW to 10 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1990	$120,000	$59,700
	Valley Stream	$50	350	60	$17,500	$3,000
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$450,700
	Net (Gen minus Load)			0		$24,300

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	-90	$1,800
	Total			$24,300
	DAMCR (Gen minus Load minus Congestion)			$0

PAR LOADING SCENARIO (901 Line Flow Increased from 100 MW to 120 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1880	$120,000	$56,400
	Valley Stream	$50	350	170	$17,500	$8,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,900
	Net (Gen minus Load)			0		$22,100

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	20	-$400
	Total			$22,100
	DAMCR (Gen minus Load minus Congestion)			$0

IV. External Interface Scheduling

New York imports a substantial amount of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. Additionally, five controllable lines (the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, and the Neptune Cable) connect Long Island and New York City directly to PJM and New England, collectively providing up to 2.2 GW of imports to downstate areas.[260,261] Given the substantial transfer capability between New York and the adjacent regions relative to New York's total power consumption, efficient scheduling of these interfaces is crucial.

Efficient use of transmission interfaces between regions offers two key benefits:

- First, access to external resources reduces costs of serving New York load when lower-cost external resources are available. Likewise, lower-cost internal resources gain the ability to compete to serve load in adjacent regions.
- Second, the ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the cost of meeting reliability standards in each control area.

This section evaluates transaction scheduling between New York and adjacent control areas:

- Subsection A summarizes scheduling between New York and adjacent control areas;
- Subsection B evaluates convergence of prices between New York and neighboring control areas;
- Subsection C examines the efficiency of Coordinated Transaction Scheduling ("CTS"), including an evaluation of transaction offer patterns and profitability;
- Subsection D provides a systematic evaluation of factors that lead to inconsistencies between the RTC evaluation, which schedules CTS transactions every 15 minutes, and the RTD evaluation, which determines real-time prices every five minutes that are used for settlements; and
- Subsection E examines several key factors that lead to inconsistencies between RTC and RTD in more details.

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260 Cross Sound Cable ("CSC") connects Long Island to Connecticut with a transfer capability of 330 MW. Neptune Cable connects Long Island to New Jersey with a transfer capability of 660 MW. Northport-to-Norwalk line ("1385 Line") connects Long Island to Connecticut with a transfer capability of 200 MW. Linden VFT Line connects New York City to PJM with a transfer capability of 315 MW. Hudson Transmission Project ("HTP Line") connects New York City to New Jersey with a transfer capability of 660 MW.

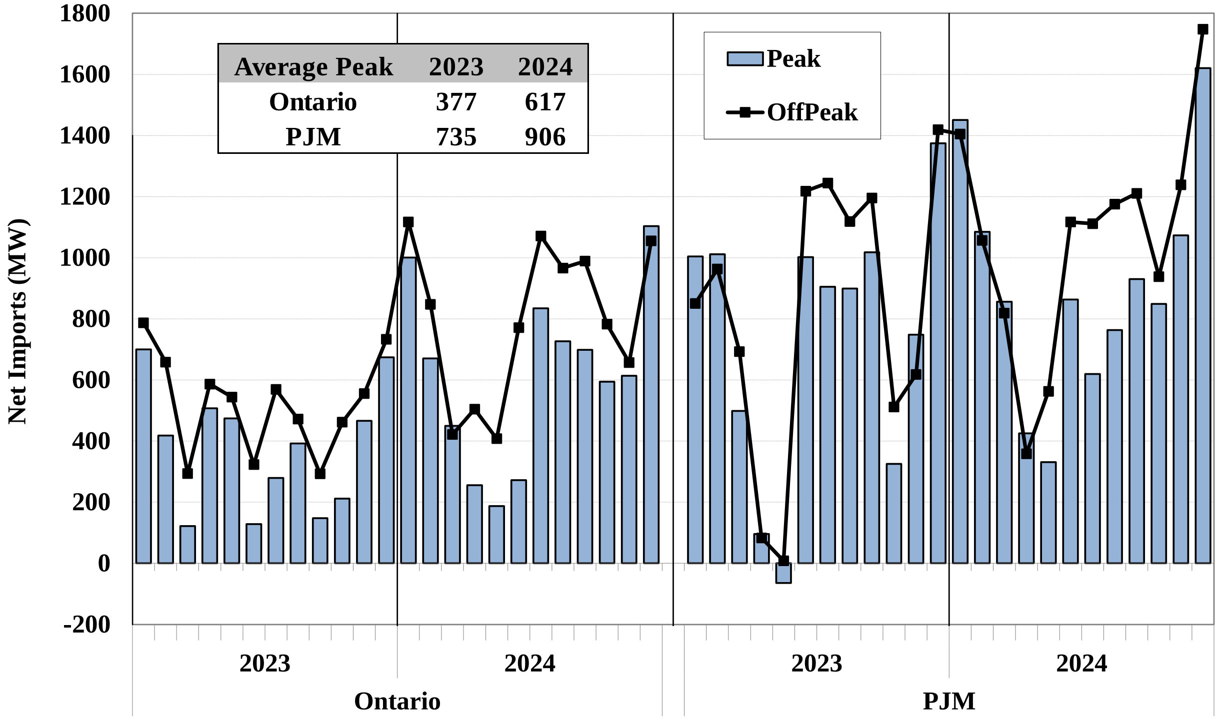
261 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the "Dennison Scheduled Line" and is scheduled separately from the primary interface between New York and Quebec.

A. Summary of Scheduled Imports and Exports

Figure A-54Figure A-54 to Figure A-57 Figure A-57 : Average Net Imports from Ontario, PJM, Quebec, and New England

The following four figures summarize the net scheduled interchanges in real-time between New York and neighboring control areas in 2023 and 2024. The net scheduled interchange does not include unscheduled power flows (i.e., loop flows). For each interface, average scheduled net imports are shown by month for peak (i.e., 6 am to 10 pm, Monday through Friday) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure A-54, the primary interfaces with Quebec and New England in Figure A-55, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-56 and Figure A-57.

Figure A-54: Monthly Average Net Imports from Ontario and PJM
2023 – 2024



Average Peak	2023	2024
Ontario	377	617
PJM	735	906

Figure A-55: Monthly Average Net Imports from Quebec and New England
2023 – 2024

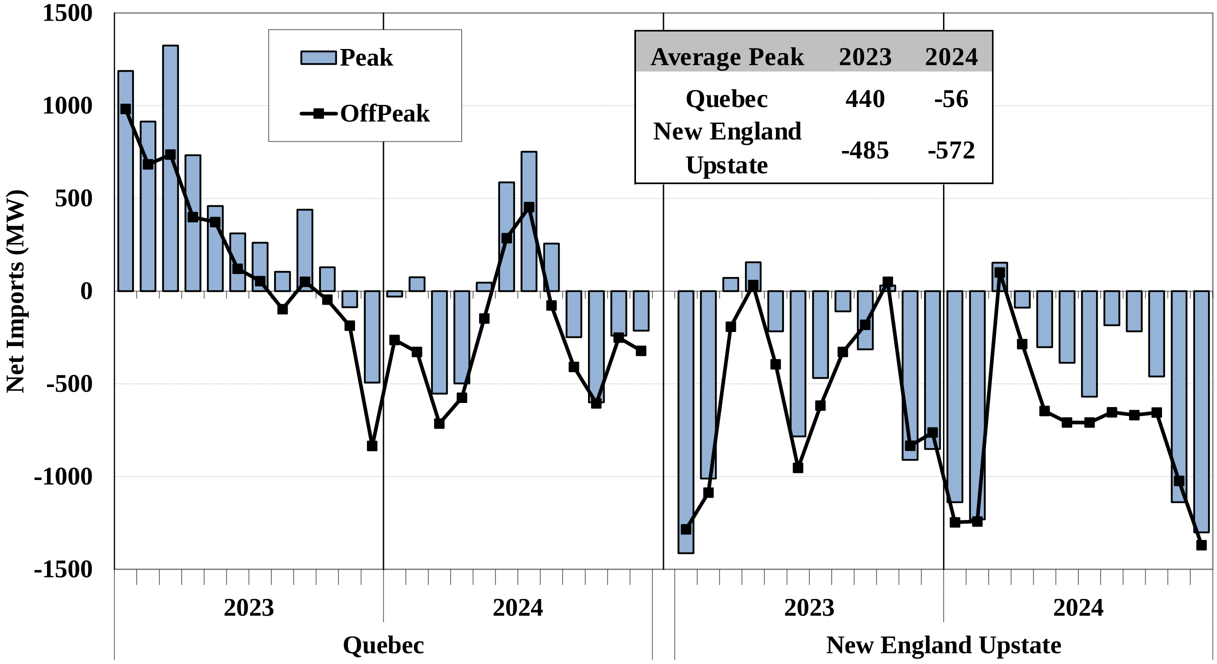


Figure A-56: Monthly Average Net Imports into New York City
2023 – 2024

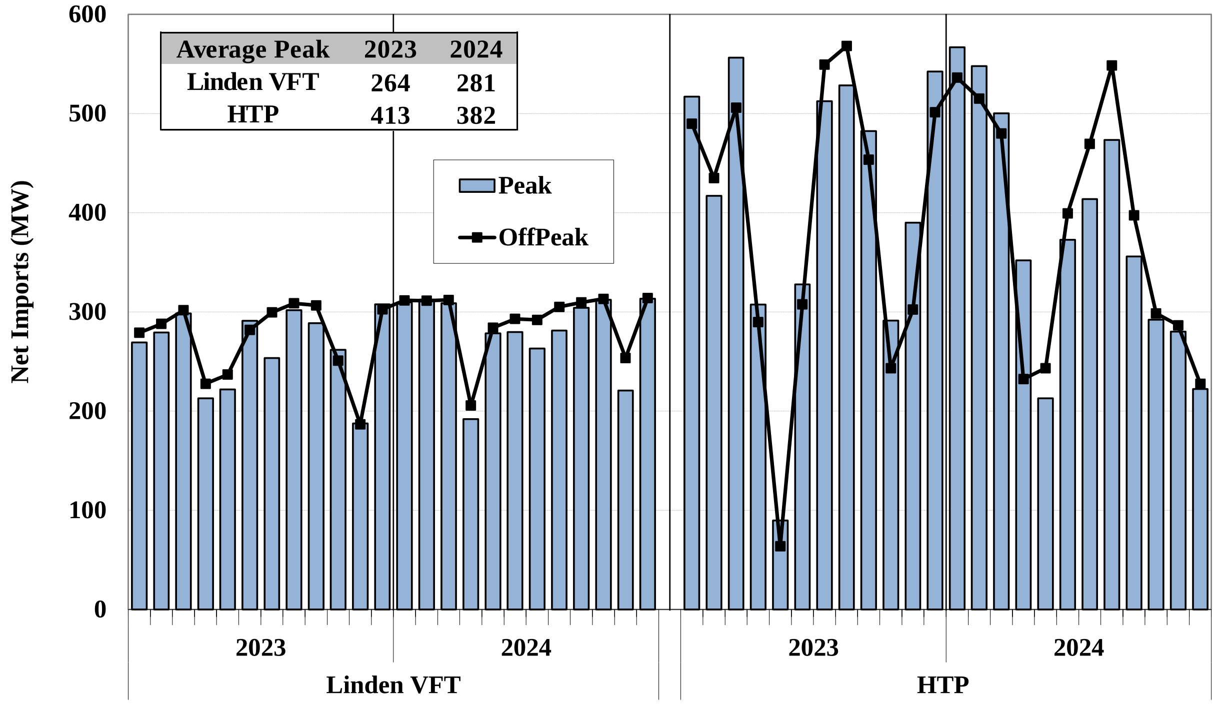
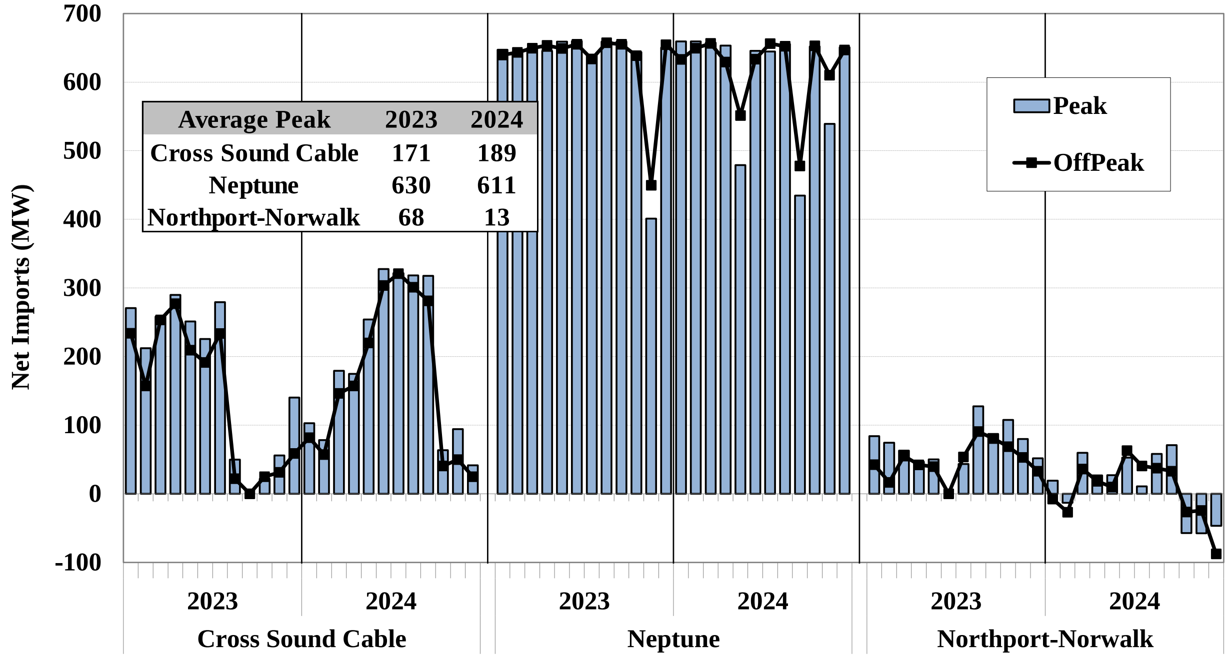


Figure A-57: Monthly Average Net Imports into Long Island
2023 – 2024



B. Price Convergence and Efficient Scheduling with Adjacent Markets

The performance of New York's wholesale electricity markets depends not only on the efficient use of internal resources, but also on the efficient use of transmission interfaces between New York and neighboring control areas. Trading between neighboring markets tends to bring prices together as participants arbitrage price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. A lack of price convergence indicates that resources are being used inefficiently, as higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region. Efficient scheduling is particularly important during shortages when flows between regions have the largest economic and reliability consequences. Moreover, efficient scheduling can also alleviate over-generation conditions that can lead to negative price spikes.

However, one cannot expect that trading by market participants alone will optimize the use of the interface. Several factors prevent real-time prices from being fully arbitraged.

- Market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible.
- Differences in scheduling procedures and timing in the markets are barriers to arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants would not be willing to schedule additional power between regions unless they anticipate a price difference greater than these costs.

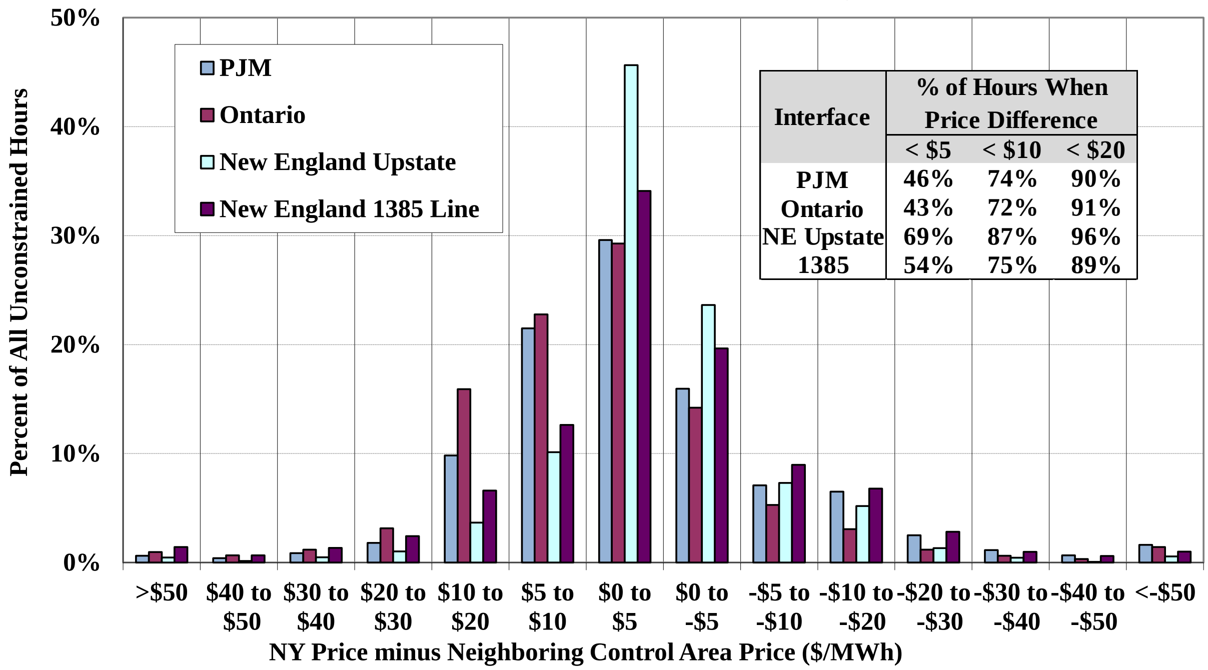
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-58: Price Convergence Between New York and Adjacent Markets

Figure A-58 evaluates scheduling between New York and adjacent RTO markets across interfaces with open access scheduling. The Neptune Cable, the Linden VFT Line, the HTP Line, and the Cross Sound Cable are omitted because these are Designated Scheduled Lines, which have alternate systems to allocate transmission reservations. RTOs have real-time markets, which allow participants to schedule market-to-market transactions based on transparent price signals in each region. Based on the prevailing prices in each market, we can evaluate whether the interface is scheduled efficiently.

Figure A-58 summarizes price differences between New York and neighboring markets during unconstrained hours in 2024. In these hours, there were no NYISO constraints that prevented scheduling. However, in some of these hours, there may have been constraints that prevented the other ISOs from scheduling transactions.[262] In the figure, the horizontal axis shows the range of price differences between New York and the adjacent control areas at the border. The heights of the bars represent the fraction of hours in each price difference category.

Figure A-58: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2024



262 In these hours, prices in neighboring RTOs (i.e., prices at the NYISO proxy in each RTO market) reflect transmission constraints in those markets.

Table A-7: Efficiency of Inter-Market Scheduling

Table A-7 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2024. It evaluates transaction schedules and clearing prices between New York and the three markets across the three primary interfaces and five scheduled lines (i.e., the 1385 Line, the Cross Sound Cable, the Neptune Cable, the HTP Line, and the Linden VFT interface).

The table shows the following quantities:

- The estimated production cost savings that result from the flows across each interface. The estimated production cost savings in each hour is based on the price difference across the interface multiplied by the scheduled power flow across the interface.[263]
- Average hourly flows between neighboring markets and New York. A positive number indicates a net import from neighboring areas to New York.
- Average price differences between markets for each interface. A positive number indicates that the average price was higher on the New York side of the interface. [264]
- The share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-priced market).

The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market. So, this analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[265]

Table A-7 evaluates the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but this will induce other firms to schedule counter-flow transactions, thereby offsetting the effect of

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263 For example, if 100 MW flows from PJM to New York across its primary interface during one hour, the price in PJM is $50 per MWh, and the price in New York is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10). This is because each MW of flow saves $10 by allowing a $60 per MWh resource in New York to ramp down and be replaced by a $50 per MWh resource in PJM. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from the high-priced region towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

264 The real-time Hourly Ontario Energy Price ("HOEP") is used at the Ontario side of the interface for both the day-ahead and real-time markets.

265 For example, if 100 MW is scheduled from the low-priced to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

the individual transaction. Ultimately, the net scheduled interchange is what determines how much of the generation resources in one control area will be used to satisfy load in another control area, which determines whether the external interface is used efficiently.

Table A-7: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2024

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)*	Average Net Imports (MW)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)*
Free-flowing Ties								
New England	-817	$0.66	48%	-$5.6	149	$1.01	61%	$4.5
Ontario	542	$4.89	77%	$25.9	171	$4.01	64%	$9.9
PJM	1,099	$2.58	70%	$24.3	-112	$0.67	52%	$5.9
Controllable Ties								
1385 Line	18	$0.78	69%	$2.4	-9	$0.92	54%	$1.3
Cross Sound Cable	173	$4.94	74%	$12.0	4	$4.23	54%	$0.5
Neptune	622	$12.77	95%	$70.2	-5	$11.59	37%	-$1.1
HTP	371	$10.19	94%	$33.5	13	$9.35	60%	$1.4
Linden VFT	286	$9.15	93%	$24.3	1	$9.31	56%	$0.5

* The estimated production cost savings tend to: 1) under-estimate actual savings when power flows from the low-priced region to the high-priced region, since if flows were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall; while 2) over-estimate actual cost increases when power flows from the high-priced region to the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

C. Evaluation of Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") enhances efficiency by allowing two wholesale market operators to exchange price information shortly before real-time, aiding market participants in scheduling external transactions more efficiently. Compared to hourly LBMP-based scheduling, the CTS intra-hour scheduling system offers two key advantages:

- **Timeliness:** CTS schedules transactions less than 30 minutes ahead, whereas hourly LBMP-based schedules are established up to 105 minutes in advance, benefiting from more accurate system information.
- **Flexibility:** Interface flows adjust every 15 minutes instead of every 60 minutes, enabling a more efficient response to changing real-time conditions.

Figure A-59: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

Figure A-59 shows the average amount of CTS transactions offered and scheduled at the primary PJM and New England interfaces during peak hours (i.e., HB 7 to 22) in each month of 2024. Positive numbers indicate import offers to New York and negative numbers represent export bids to PJM or New England. Stacked bars show the average quantities of price-sensitive CTS bids for the following three price ranges: (a) between -$10 and $5/MWh; (b) between $5 and

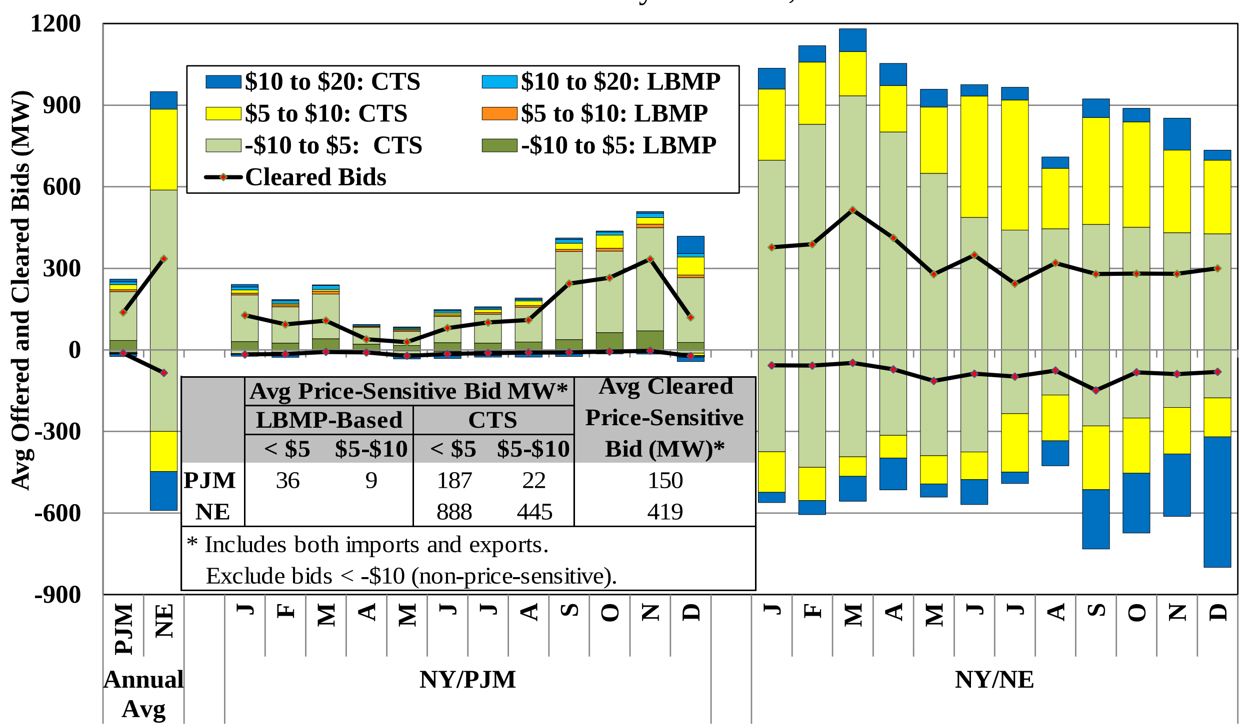
$10/MWh; and (c) between $10 and $20/MWh.[266] Bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis. Unlike the primary New England interface where only CTS bids are allowed, traditional LBMP-based bids and CTS bids are both allowed at the PJM interface. To make a fair comparison between the two primary interfaces, LBMP-based bids at the PJM interface are converted to equivalent CTS bids and are shown in the figure as well. The equivalent CTS bids are constructed as:

- Equivalent CTS bid to import = LBMP-based import offer – PJM Forecast Price
- Equivalent CTS bid to export = PJM Forecast Price – LBMP-based export bid

The two black lines in the chart indicate the average scheduled price-sensitive imports and exports (including both CTS and LBMP-based bids) in each month. The table in the figure summarizes for the two CTS-enabled interfaces: a) the average amount of price-sensitive bids with low offer prices, which are either less than $5/MWh or between $5 and $10/MWh; and b) the average cleared price-sensitive bids in 2024.

Figure A-59: Price-Sensitive Real-Time Transaction Bids and Offers by Month

PJM and NE Primary Interfaces, 2024



266 RTC evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the bid price and (b) PJM's or NE's forecast marginal price at the border. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to: (a) PJM's or NE's forecast marginal price at the border less (b) the bid price.

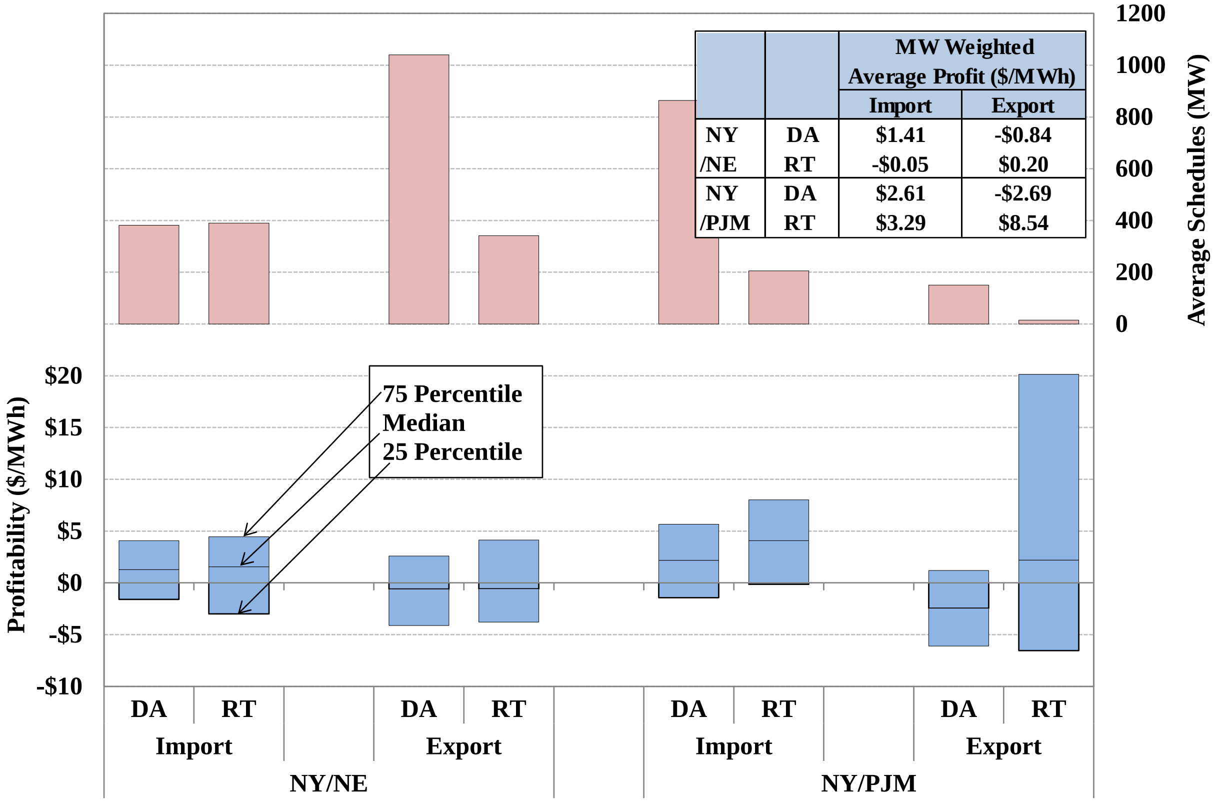
Figure A-60: Transaction Profitability at the Primary PJM and NE Interfaces

The second analysis examines the profitability of scheduled transactions at the two CTS-enabled interfaces. In the bottom portion of Figure A-60, the column bars indicate the profitability spread of the middle two quartiles (i.e., 25 to 75 percentile) in 2024. The line inside each bar denotes the median value of the distribution. These are shown separately for imports and exports at the two interfaces. Scheduled transactions are categorized in the following two groups:

- *Day-ahead* – Transactions that are scheduled in the day-ahead market and actually flow in real-time. This excludes virtual imports and exports, which have a day-ahead schedule but do not bid/offer in real-time.
- *Real-time* – Transactions not offered or scheduled in the day-ahead but scheduled in the real-time (i.e., day-ahead schedules are zero, but real-time schedules are not zero).

The bars in the top portion of the figure show the average quantity of scheduled transactions for each category in 2024 and the inset table summarizes the annual average profit.

Figure A-60: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2024



		MW Weighted Average Profit ($/MWh)	
		Import	Export
NY /NE	DA	$1.41	-$0.84
	RT	-$0.05	$0.20
NY /PJM	DA	$2.61	-$2.69
	RT	$3.29	$8.54

Table A-8: Efficiency of Intra-Hour Scheduling Under CTS

The next analysis evaluates the efficiency of the CTS-enabled intra-hour scheduling process (relative to our estimates of the scheduling outcomes that would have occurred under the hourly scheduling process) with PJM and New England.

To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, it is first necessary to estimate an hourly interchange schedule that would have flowed if the intra-hour process was not in place. We estimate the base interchange schedule by calculating the average of the four advisory quarter-hour schedules during the hour for which RTC_{15} determined final schedules at each hourly-scheduling interface. [267]

Table A-8 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2024. The table shows the following quantities:

- % of All Intervals with Adjustment– This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule) in the scheduling RTC interval.
- Average Flow Adjustment – This measures the difference between the estimated hourly schedule and the final schedule. Positive numbers indicate flow adjustments in the import direction (i.e., from PJM or New England to New York) and negative numbers indicate flow adjustments in the export direction (i.e., from New York to PJM or New England).
- Production Cost Savings – This measures the market efficiency gains (and losses) that resulted from the CTS processes.
  - Projected Savings at Scheduling Time – This measures the expected production cost savings at the time when RTC determines the interchange schedule across the two primary interfaces.[268]
  - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled, and/or scheduled in the inefficient direction. This estimates the portion of savings that inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors. [269]
  - Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:

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267 RTC_{15} is the RTC run that posts the results by the time 15 minutes past each hour. The first interval of each RTC_{15} is ending at 30 minutes past each hour. For each hourly-scheduling interface, each RTC_{15} makes binding schedules for the second calendar hour in its two-and-a-half optimization period. For example, the first RTC_{15} of each day posts market results by 0:15 am; the first interval of its two-and-a-half optimization period is ending at 0:30 am; and it makes binding transaction schedules for all hourly-scheduling interfaces for the hour beginning at 1:00 am.

268 This is calculated as (final RTC schedule – estimated hourly schedule)*(RTC price at the PJM/NE proxy – PJM/NE forecast price at the NYIS proxy). An adjustment was also made to this estimate, which is described in Footnote 273.

269 This is calculated as: a) (final RTC schedule – estimated hourly schedule)*(RTD price – RTC price) for NYISO forecast error; b) (final RTC schedule – estimated hourly schedule)*(PJM forecast price – PJM RT price) for PJM forecast error; and c) (final RTC schedule – estimated hourly schedule)*(NE forecast price – NE RT price) for NE forecast error.

   - Real-time Curtailment[270] - Some of RTC scheduled transactions may not actually flow in real-time for various reasons (e.g., check-out failures, real-time cuts for security and reliability concerns, etc.). The reduction of flows in the efficient direction reduces market efficiency gains.
   - Interface Ramping[271] - RTD and RTC have different assumptions regarding interface schedule ramping. In RTD, interface flows start to ramp at 5 minutes before each quarter-hour interval and reach the target level at 5 minutes after. RTC assumes that the target flow level is reached at the top of the quarter-hour interval. Therefore, an inherent difference exists between RTD flows and RTC flows at the top of each quarter-hour interval, which will lead a portion of projected savings to be unrealized in real time.
   - Price Curve Approximation – This applies only to the CTS process between New York and New England. CTSPE forecasts a 7-point piecewise linear supply curve and NYISO transfers it into a step-function curve for use in the CTS process (as shown in Figure A-62). This leads to differences between the marginal cost of interchange estimated by ISO-NE and the assumptions used by the NYISO for scheduling.
  - Actual Savings[272,273] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).
- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.

270 This is calculated as (final RTD schedule – final RTC schedule with ramping assumption at the top of quarter-hour interval)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy).

271 This is calculated as (final RTC schedule with ramping assumption at the top of quarter-hour interval – final RTC schedule without ramping assumption)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy).

272 This is also calculated as (final RTD schedule – estimated hourly schedule)*(RTD price at the PJM/NE proxy – PJM/NE RT price at the NY proxy) + an Adjustment (as described below).

273 The marginal cost of production is estimated from LBMPs that result from scheduling a transaction, but the marginal cost of production varies as the interface schedule is adjusted. For example, if 100 MW is scheduled to flow from PJM or NE to NYISO, reducing the price spread between markets from $12/MWh to $5/MWh, our unadjusted production cost savings estimate from the transaction would be $500/hour (= 100 MW x $5/MWh). However, if the change in production costs was linear in this example, the true savings would be $850/hour (= 100 MW x Average of $5 and $12/MWh). We make a similar adjustment to our estimate of marginal cost of production assuming that: a) the supply curve was linear in all three markets; b) at the NY/PJM border, a 100 MW movement in the supply curve changes the marginal cost by 7.5 percent of NY LBMP in the New York market and 2.5 percent of PJM LBMP in the PJM market; and c) at the NY/NE border, a 100 MW movement in the supply curve changes the marginal cost by 15 percent of NY LBMP in the New York market and 5 percent of NE LBMP in the NE market.

- Price Forecast Errors – These measure the performance of price forecasting by showing the average difference and the average absolute difference between the actual and forecasted prices on both sides of the interfaces.

To examine how price forecast errors affected efficiency gains, these numbers are shown separately for the intervals during which forecast errors are less than $20/MWh and the intervals during which forecast errors exceed $20/MWh.

Table A-8: Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and New England Interfaces, 2024

			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			75%	9%	**84%**		44%	15%	**59%**	
Average Flow Adjustment (MW)	Net Imports		40	51	**41**		-5	-72	**-22**	
	Gross		135	177	**140**		90	129	**100**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$8.3	$4.9	**$13.2**		$2.3	$10.3	**$12.6**	
	Net Over-Projection by:	NY	-$0.4	-$1.3	**-$1.7**		-$0.1	$0.3	**$0.1**	
		NE or PJM	$0.0	-$1.2	**-$1.2**		-$0.9	-$10.3	**-$11.1**	
	Other Unrealized Savings		-$0.3	-$0.7	**-$1.0**		-$0.1	-$0.2	**-$0.3**	
	Actual Savings		$7.6	$1.7	**$9.3**		$1.2	$0.1	**$1.4**	
Interface Prices ($/MWh)	NY	Actual	$31.87	$75.34	**$36.38**	**$36.05**	$29.99	$49.30	**$34.79**	**$33.68**
		Forecast	$32.66	$70.35	**$36.57**	**$36.26**	$30.72	$48.65	**$35.18**	**$34.02**
	NE or PJM	Actual	$31.43	$81.35	**$36.61**	**$38.17**	$26.44	$54.31	**$33.37**	**$31.16**
		Forecast	$31.13	$77.07	**$35.89**	**$37.74**	$28.53	$93.11	**$44.58**	**$39.86**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.79	-$4.99	**$0.19**	**$0.21**	$0.72	-$0.65	**$0.38**	**$0.34**
		Abs. Val.	$2.44	$35.15	**$5.84**	**$5.57**	$2.38	$15.86	**$5.73**	**$4.82**
	NE or PJM	Fcst. - Act.	-$0.31	-$4.28	**-$0.72**	**-$0.43**	$2.09	$38.80	**$11.21**	**$8.70**
		Abs. Val.	$3.67	$36.47	**$7.08**	**$7.38**	$5.57	$70.19	**$21.64**	**$17.91**

For Adjustment Intervals Only

For All Intervals

Figure A-61 & Figure A-62: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-61 shows the cumulative distribution of forecasting errors in 2024. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price.

Figure A-61 shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.

Figure A-62 illustrates this with example curves.[274] The blue squares in the figure show the seven price/quantity pairs that are produced by the ISO-NE price forecast engine (CTSPE). The blue line connecting these seven squares represents a piecewise linear supply curve at the New

274 The two curves are forecasted supply curves used in the market on January 5, 2016.

England border. The red step-function curve is an approximation of the piecewise linear curve and is actually used in RTC for scheduling CTS transactions at the New England border.

Figure A-61: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2024

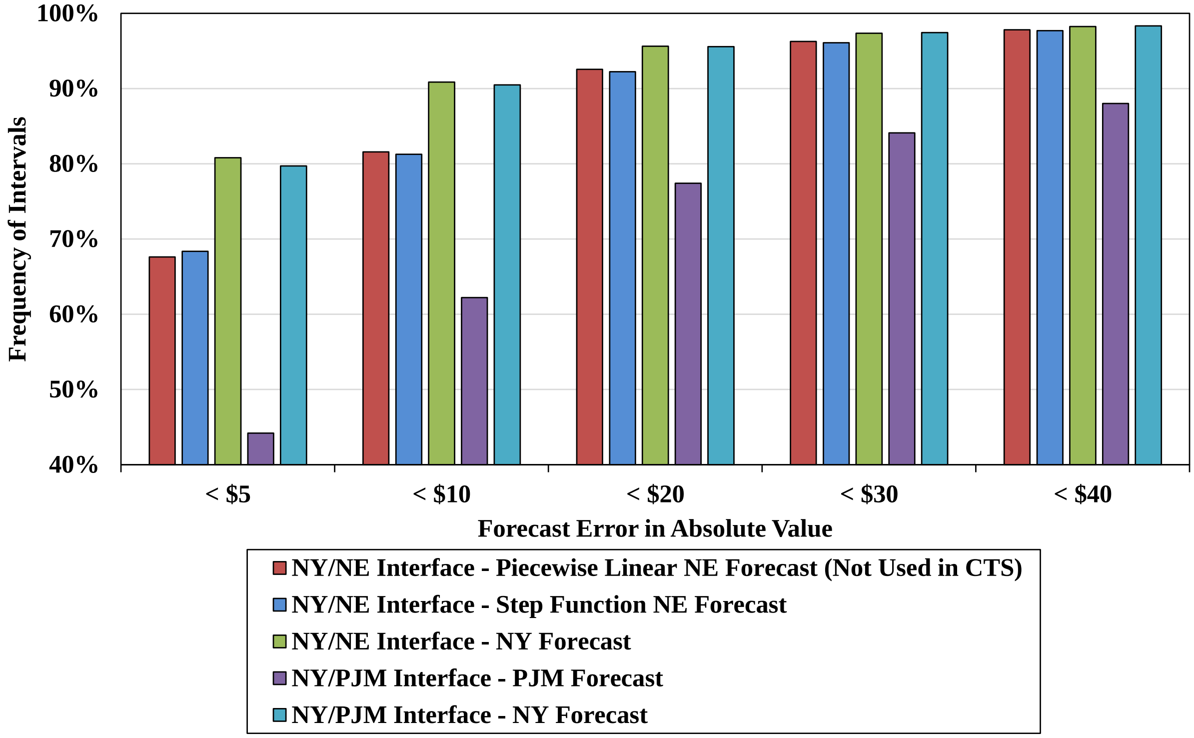
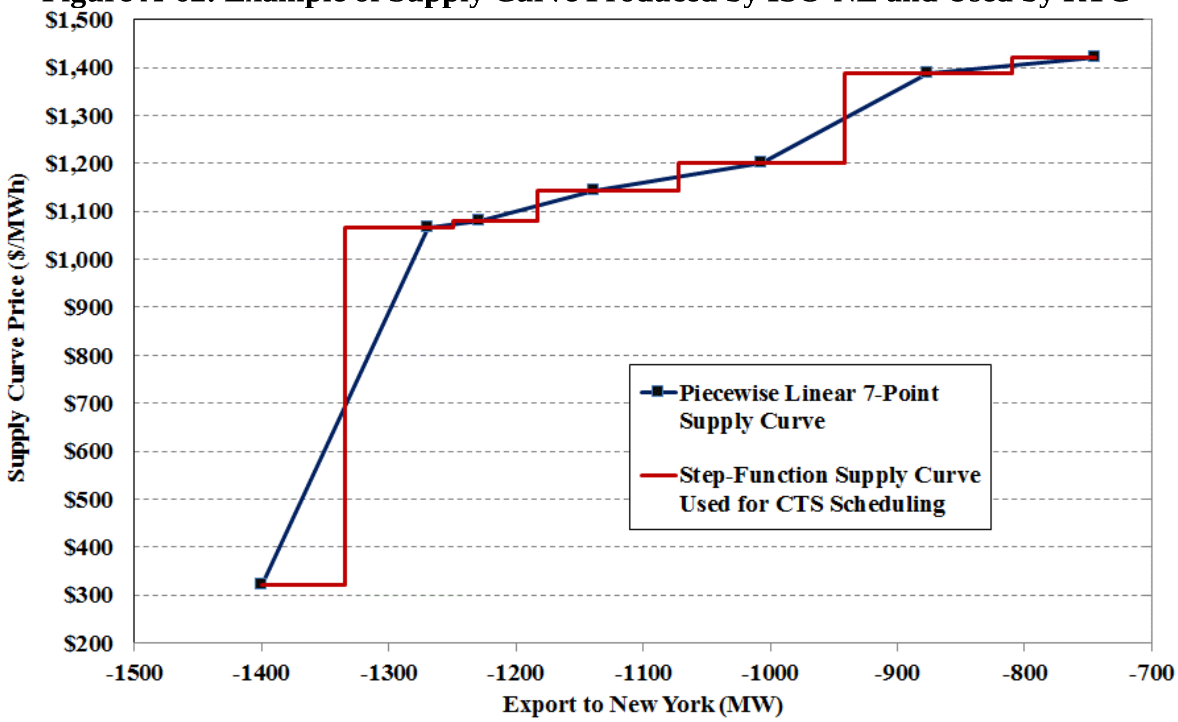


Figure A-62: Example of Supply Curve Produced by ISO-NE and Used by RTC



D. Evaluation of Factors Contributing to Inconsistency between RTC and RTD

RTC schedules gas turbines and external transactions shortly in advance of the 5-minute real-time market, so its assumptions regarding factors such as the load forecast, the wind forecast, and the ramp profile of individual resources are important.

Figure A-63 to Figure A-65: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-63 to Figure A-65 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it distinguishes between factors that *cause* differences between RTC forecast prices and actual RTD prices (which we call "detrimental" factors) and factors that *reduce* differences between RTC forecast prices and actual RTD prices (which we call "beneficial" factors). [275]

RTC schedules resources with lead times of 15 minutes to one hour, including fast start units and external transactions. Inconsistency between RTC and RTD prices is an indication that some scheduling decisions may be inefficient. For example, suppose that RTC forecasts an LBMP of $45/MWh and this leads RTC to forego 100 MW of CTS import offers priced at $50/MWh, and suppose that RTD clears at $65/MWh because actual load is higher than the load forecast in RTC and RTD satisfies the additional load with 100 MW of online generation priced at $65/MWh. In this example, the under-forecast of load leads the NYISO to use 100 MW of $65/MWh generation rather than $50/MWh of CTS imports, resulting in $1,500/hour (= 100 MW * {$65/MWh - $50/MWh}) of additional production costs. Thus, the inefficiency resulting from poor forecasting by RTC is correlated with: (a) the inconsistency between the MW value used in RTC versus the one used in RTD, and (b) the inconsistency between the price forecasted by RTC versus the actual price determined by RTD. Hence, we use a metric that multiplies the MW-differential between RTC and RTD with the corresponding price-differential for resources that are explicitly considered and priced by the real-time models.

For a generator, external transaction, or load i, our inconsistency metric is calculated as follows:

$$\text{Metric}_{i} = (\text{NetInjectionMW}_{i,RTC} - \text{NetInjectionMW}_{i,RTD}) * (\text{Price}_{i,RTC} - \text{Price}_{i,RTD})$$ [276]

Hence, for the load forecast in the example above, the metric is:

$$\text{Metric}_{load} = 100\text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = -\$2{,}000/\text{hour}$$

275 Although RTC produces ten forecasts looking 150 minutes into the future, and RTD produces four forecasts looking one hour into the future that are in addition to the binding schedules and prices that are produced for the next five minutes, this metric is calculated comparing just the 15-minute ahead forecast of RTC (which sets the interchange schedules for the interfaces with PJM and ISO-NE that use CTS) to the 5-minute financially binding interval of RTD. Future reports will perform the analysis based on other time frames as well.

276 Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

For the high-cost generator in the example above, the metric is:

$$Metric_{generator} = -100\ MW * (\$45/MWh - \$65/MWh) = +\$2{,}000/hour$$

For the foregone CTS imports in the example above, the metric is:

$$Metric_{import} = 0\ MW * (\$45/MWh - \$65/MWh) = \$0/hour$$

The metric produces a negative value for the load forecast, indicating that the under-forecast of load was a "detrimental" factor that contributed to the divergence between the RTC forecast price and the actual RTD price. The metric produces a positive value for the generator that responded to the need for additional supply in RTD, indicating that the generator's response was a "beneficial" factor that helped limit the divergence between the RTC forecast price and the actual RTD price. The metric produces a zero value for the foregone CTS imports, recognizing that the divergence was not caused by the CTS imports not being scheduled, but rather that their not being scheduled was the result of poor forecasting.

For PAR-controlled line i, our inconsistency metric is calculated across binding constraints c:

$$Metric_i = (FlowMW_{i,RTC} - FlowMW_{i,RTD}) * \sum_c \{(ShadowPrice_{c,RTC} * ShiftFactor_{i,c,RTC} - ShadowPriceMW_{c,RTD} * ShiftFactor_{i,c,RTD})\}$$

Hence, for a PAR-controlled line that is capable of relieving congestion on a binding constraint, if the flow on the PAR-controlled line is higher in RTD than in RTC and the shadow price of the constraint is higher in RTD than in RTC, the metric will produce a positive value, indicating that the PAR-controlled line had a beneficial inconsistency (i.e., it helped reduce the divergence between RTC and RTD congestion prices). However, if the flow on the PAR-controlled line decreases in RTD while the shadow price is increasing, the metric will produce a negative value, indicating that the PAR-controlled line had a detrimental inconsistency (i.e., it contributed to the divergence between RTC and RTD congestion prices). This calculation is performed for both "optimized" PARs and "non-optimized" PARs.[277]

For transmission constraints that are modeled, it is also important to quantify inconsistencies that lead to divergence between RTC and RTD. To the extent that such inconsistencies result from reductions in available transfer capability that increase congestion, the metric will produce a negative (i.e., detrimental) result. On the other hand, if inconsistencies result from an increase in transfer capability that helps ameliorate an increase in congestion, the metric will produce a positive (i.e., beneficial) result. For each limiting facility/contingency pair c, the calculation utilizes the shift factors and schedules for resources and other inputs i:

$$Metric\_BindingTx_c = ShadowPrice_{c,RTC} * \sum_i \{ShiftFactor_{i,c,RTC} * (MW_{i,RTC} - MW_{i,RTD})\} - ShadowPrice_{c,RTD} * \sum_i \{ShiftFactor_{i,c,RTD} * (MW_{i,RTC} - MW_{i,RTD})\}$$

277 A PAR is called "non-optimized" if the RTC and RTD models treat the flow as a fixed value in the optimization engine, while a PAR is called "optimized" if the optimization engines of the RTC and RTD models treat the flow as a flexible within some range.

Once the metric is calculated for each optimized PAR and each binding constraint, the transmission system is divided into regions and if a particular region has optimized PARs and/or binding constraints with positive and negative values, the following adjustments are used. If the sum across all values is positive, then each positive value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossPositive} and each negative value is discarded. If the sum across all values is negative, then each negative value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossNegative} and each positive value is discarded. This is done because when transfer capability on one facility in a particular region is reduced, the optimization engine often increases utilization of parallel circuits, so the adjustments above are helpful in discerning whether the net effect was beneficial or detrimental.

Example 1

The following two-node example illustrates how the metrics would be calculated if a transmission line tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose, RTC forecasts:

- Load_{A} = 100 MW and Load_{B} = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);
- Gen_{A} produces 250 MW at a cost of $20/MWh and Gen_{B} produces 50 MW at a cost of $30/MWh; and
- Thus, in RTC, Price_{A} = $20/MWh, Price_{B} = $30/MWh, Flow_{AB1} on Line 1 = 50 MW, so the ShadowPrice_{AB1} = $30/MWh.

Suppose that before RTD runs, Line 2 trips, reducing flows from Node A to Node B and requiring output from a $45/MWh generator at Node B. This will lead to the following changes:

- Only two transmission lines (Lines 1 and 3) with equal impedance connect A to B, so the shift factor of node A on Line 1 is 0.5 (assuming node B is the reference bus);
- Gen_{A} produces 200 MW at a cost of $20/MWh, Gen_{B} produces 50 MW at a cost of $30/MWh, and Gen_{B2} produces 50 MW at a cost of $45/MWh; and
- Thus, in RTD, Price_{A} = $20/MWh, Price_{B} = $45/MWh, Flow_{AB1} on Line 1 = 50 MW, so the ShadowPrice_{AB1} = $50/MWh.

In this example, the metric would be calculated as follows for each input:

- Metric_Load_{A} = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)
- Metric_Load_{B} = $0 = (-200MW - -200MW) * ($30/MWh - $45/MWh)
- Metric_Gen_{A} = $0 = (250MW - 200MW) * ($20/MWh - $20/MWh)
- Metric_Gen_{B} = $0 = (50MW - 50MW) * ($30/MWh - $45/MWh)
- Metric_Gen_{B2} = $750/hour = (0MW - 50MW) * ($30/MWh - $45/MWh)
- Metric_BindingTx = -$750/hour = $30/MWh * 0.333 * (250MW - 200MW) – $50/MWh * 0.5 * (250MW - 200MW)

- Metric_BindingTx exhibits a negative value, indicating a detrimental factor because the divergence between RTC prices and RTD prices was caused by a reduction in transfer capability from Node A to Node B. Metric_Gen$_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Example 2

The following two-node example illustrates how the metrics would be calculated if a generator tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose RTC forecasts:

- Load$_A$ = 100 MW and Load$_B$ = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);
- Gen$_A$ produces 200 MW at a cost of $20/MWh and Gen$_B$ produces 100 MW at a cost of $20/MWh; and
- Thus, in RTC, Price$_A$ = $20/MWh, Price$_B$ = $20/MWh, Flow$_{AB1}$ on Line 1 = 33.33 MW, so the ShadowPrice$_{AB1}$ = $0/MWh.

Suppose that before RTD runs, Gen$_B$ trips, increasing flows from Node A to Node B from 100 MW to 150 MW, requiring 50 MW of additional production from Gen$_A$ and requiring 50 MW of production from a $45/MWh generator at Node B. This will lead to the following changes:

- Gen$_A$ produces 250 MW at a cost of $20/MWh and Gen$_{B2}$ produces 50 MW at a cost of $45/MWh; and
- Thus, in RTD, Price$_A$ = $20/MWh, Price$_B$ = $45/MWh, Flow$_{AB1}$ on Line 1 = 50 MW, so the ShadowPrice$_{AB1}$ = $75/MWh.

In this example, the metric would be calculated as follows for each input:

- Metric_Load$_A$ = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)
- Metric_Load$_B$ = $0 = (-200MW - -200MW) * ($20/MWh - $45/MWh)
- Metric_Gen$_A$ = $0 = (200MW - 250MW) * ($20/MWh - $20/MWh)
- Metric_Gen$_B$ = -$2,500/hour = (100MW - 0MW) * ($20/MWh - $45/MWh)
- Metric_Gen$_{B2}$ = $1,250/hour = (0MW - 50MW) * ($20/MWh - $45/MWh)
- Metric_BindingTx = $1,250/hour = $0/MWh * 0.333 * (200MW - 250MW) – $75/MWh * 0.333 * (200MW - 250MW)
- Metric_BindingTx exhibits a positive value, indicating a beneficial factor because excess transfer capability was utilized to reduce the divergence between RTC prices and RTD prices that was caused by the generator trip at Node B. Metric_Gen$_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and

RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Categories of Factors Affecting RTC/RTD Price Divergence

RTC and RTD forecasts are based on numerous inputs. We summarize inputs that change between RTC and RTD in the following ten categories for the purposes of this analysis:

- Load Forecast Error – Combines the forecast of the load forecasting model with any upward or downward adjustment by the operator.
- Wind Forecast Error – Uses the blended value that is a weighted average of the wind forecasting model and the current telemetered value.
- External Transaction Curtailments and Checkout Failures
- Generator Forced Outages and Derates
- Generator Not Following Schedule – Includes situations where a generator's RTD schedule is affected by a ramp-constraint and where the ramp-constraint was tighter as a result of the generator not following its schedule in a previous interval.
- Generator on OOM Dispatch
- Generator Dispatch In Merit
- NY/NJ PARs and Other Non-Optimized PARs – Includes the A, J, K, and 5018 PAR-controlled lines.
- Transmission Utilization – Includes contributions from binding constraints and optimized PARs. This category is organized into the following regional transmission corridors:
    - West Zone
    - West Zone to Central NY
    - North Zone to Central NY
    - Central East
    - UPNY-SENY & UPNY-ConEd
    - New York City
    - Long Island
- Schedule Timing and Ramp Profiling – This includes differences that result from inconsistent timing and treatment of ramp between RTC and RTD for load forecast, external interchange, self-scheduled generation, and dispatchable generation. This is illustrated for external interchange in Figure A-68.

Figure A-63 summarizes the RTC/RTD divergence metric results for detrimental factors in 2024, while Figure A-64 provides the summary for beneficial factors. Figure A-65 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-63: Detrimental Factors Causing Divergence between RTC and RTD
2024

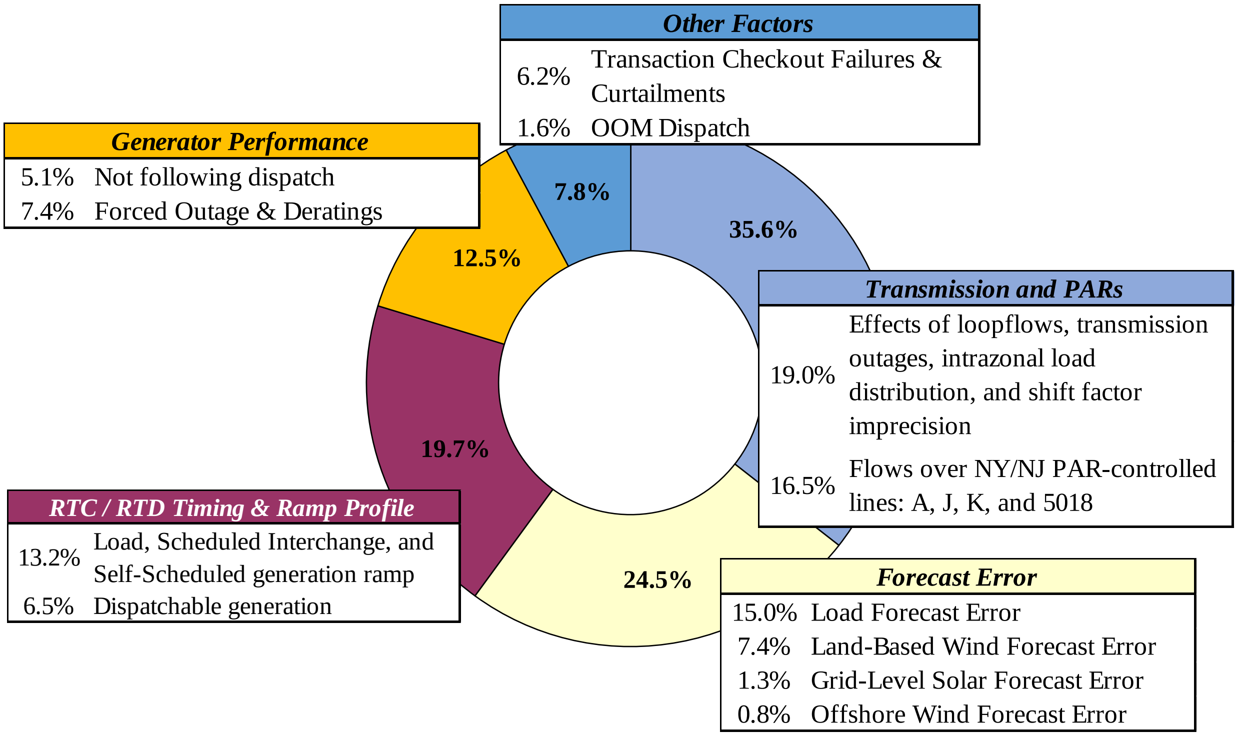


Figure A-64: Beneficial Factors Reducing Divergence between RTC and RTD
2024

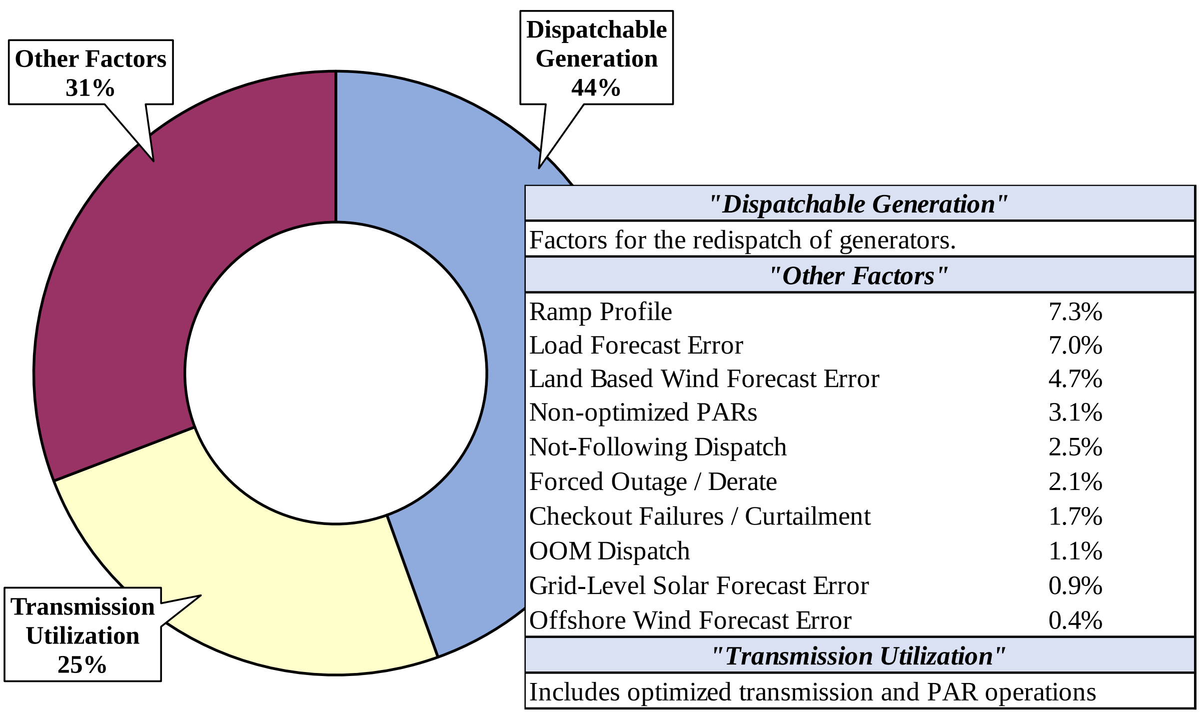
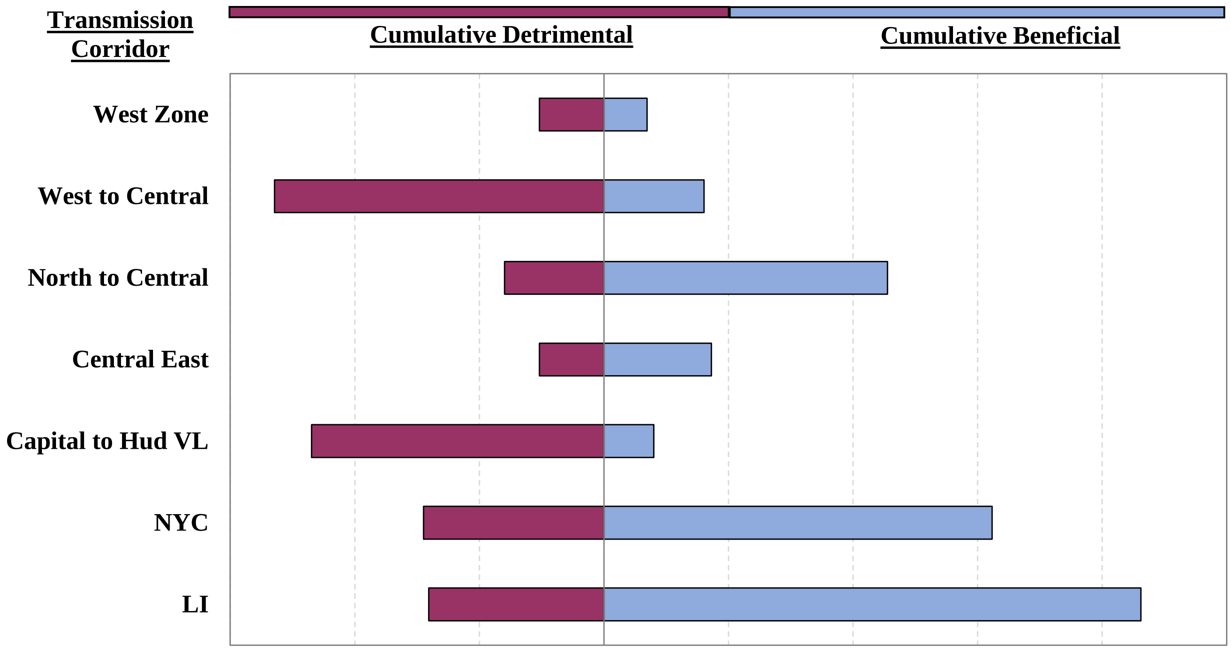


Figure A-65: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2024



E. Patterns of Key Factors Driving Price Differences between RTC and RTD

The following analyses focus on several key factors contributing to inconsistency between RTC and RTD, which (a) evaluate the magnitude and patterns of forecast errors of these factors and (b) examine how these affect the accuracy of RTC's price forecasting.

Figure A-66 & Figure A-67: Differences in Prices vs Differences in Assumptions of Net Interchanges between RTC and RTD

Figure A-66 shows a histogram of the differences in 2024 between (a) the RTC assumed net interchange and (b) the actual net interchange reflected in RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45). For each tranche of the histogram, the figure summarizes the accuracy of the RTC price forecast by showing:

- The average of the RTD LBMP minus the RTC LBMP;
- The median of the RTD LBMP minus the RTC LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

LBMPs are shown at the NYISO Reference Bus at the quarter-hour intervals for RTC and RTD.

Figure A-66: Histogram of Differences Between RTC and RTD Prices and Net Interchange
2024

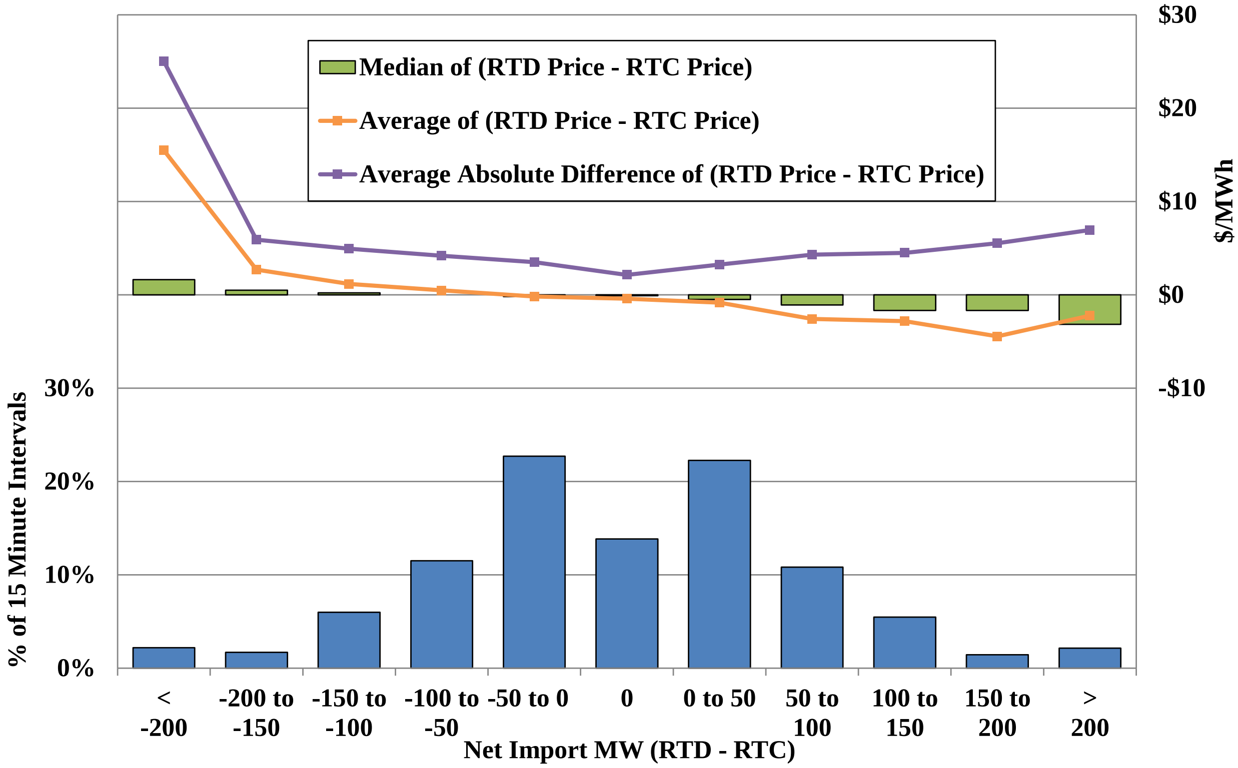


Figure A-67 shows pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels for 100+ MW tranches. The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing the average RTD LBMP minus the average RTC LBMP and the mean absolute difference between the RTD and RTC LBMPs.

Figure A-67: Differences Between RTC and RTD Prices and Net Interchange Schedules
by Time of Day, 2024

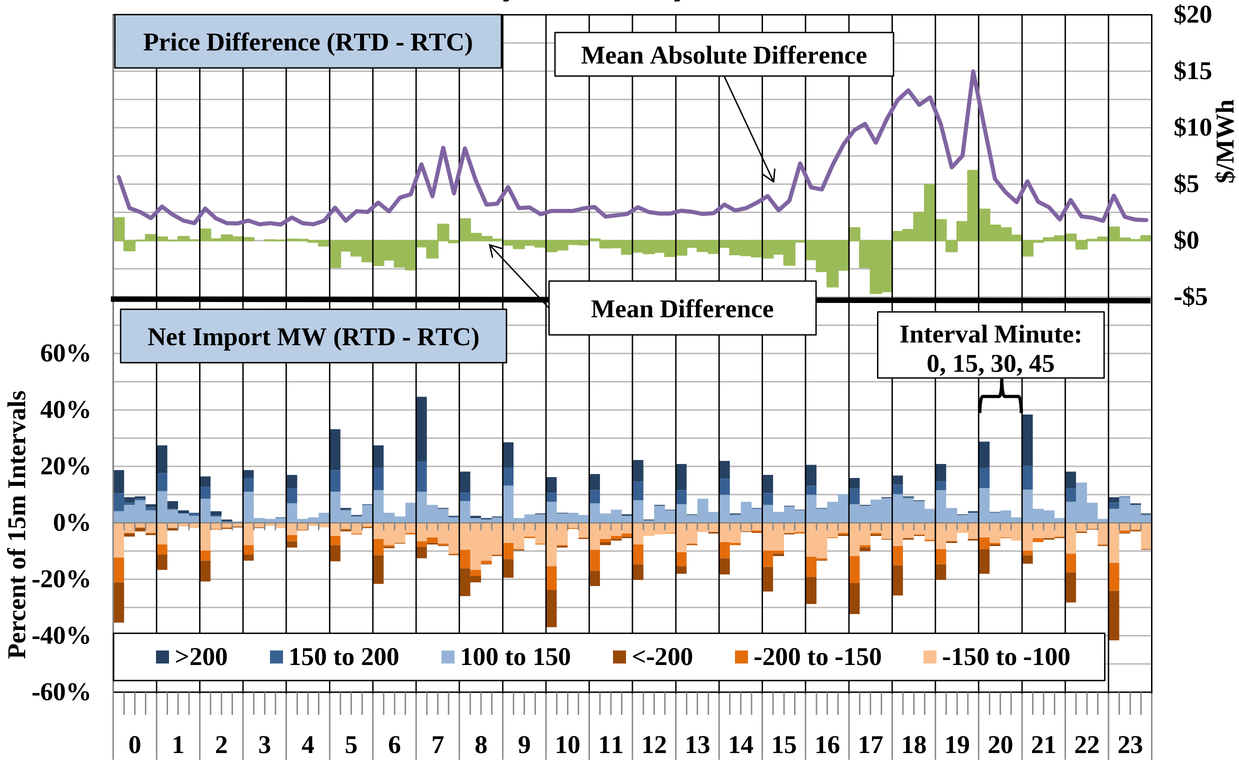


Figure A-68: Illustration of the ramp profiles that are assumed by RTC and RTD

The differences in net interchange schedules between RTC and RTD result from factors such as transaction checkout failures, curtailments by operators, and different ramp assumptions used in RTC and RTD. Figure A-68 provides an illustration of the ramp profiles that are assumed by RTC and RTD. The different ramp profiles lead to inconsistencies between RTC and RTD in the level of net imports, which contribute to differences between the RTC price forecast and actual 5-minute RTD clearing prices. Although inconsistent ramp profile assumptions are not the only source of inconsistent RTC and RTD prices, they illustrate how inconsistent modeling assumptions can lead to inconsistent pricing outcomes.

In RTD, the assumed level of net imports is based on the scheduled interchange at the end of each 5-minute period. Transactions are assumed to move over a 10-minute period from one scheduling period to the next for both hourly and 15-minute interfaces. The 10-minute period goes from five minutes before the top-of-the-hour or quarter-hour to five minutes after. On the other hand, RTC schedules transactions as if they reach their schedule at the top-of-the-hour or quarter-hour, which is five minutes earlier than RTD. Green arrows are used to show intervals when RTD imports exceed the assumption used in RTC. Red arrows are used to shown intervals when imports assumed in RTC exceed the RTD imports.

Figure A-68: Illustration of External Transaction Ramp Profiles in RTC and RTD

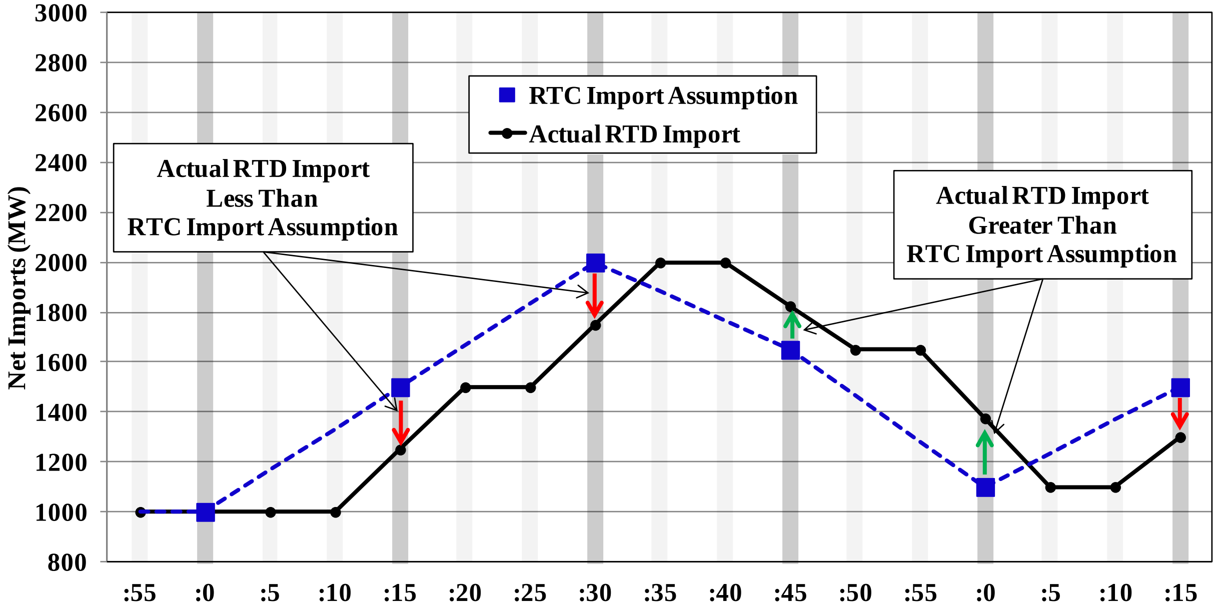


Figure A-69 & Figure A-70: Differences in Prices vs Differences in Load Forecasts between RTC and RTD

Figure A-69 shows a histogram of the differences in systemwide load forecasts (including load biases by operators) between RTC and RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45) for 2024. For each tranche of the histogram, the figure summarizes the accuracy of the RTC price by showing:

- The average of the RTC LBMP minus the RTD LBMP;
- The median of the RTC LBMP minus the RTD LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

LBMPs are shown as zonal-load-weighted prices at the quarter-hour intervals for both RTC and RTD.

Figure A-70 shows these pricing and load forecasting differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD load forecast levels in tranches. The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing:

- The average RTC LBMP minus the average RTD LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

Figure A-69: Histogram of Differences Between RTC and RTD Prices and Load Forecasts
2024

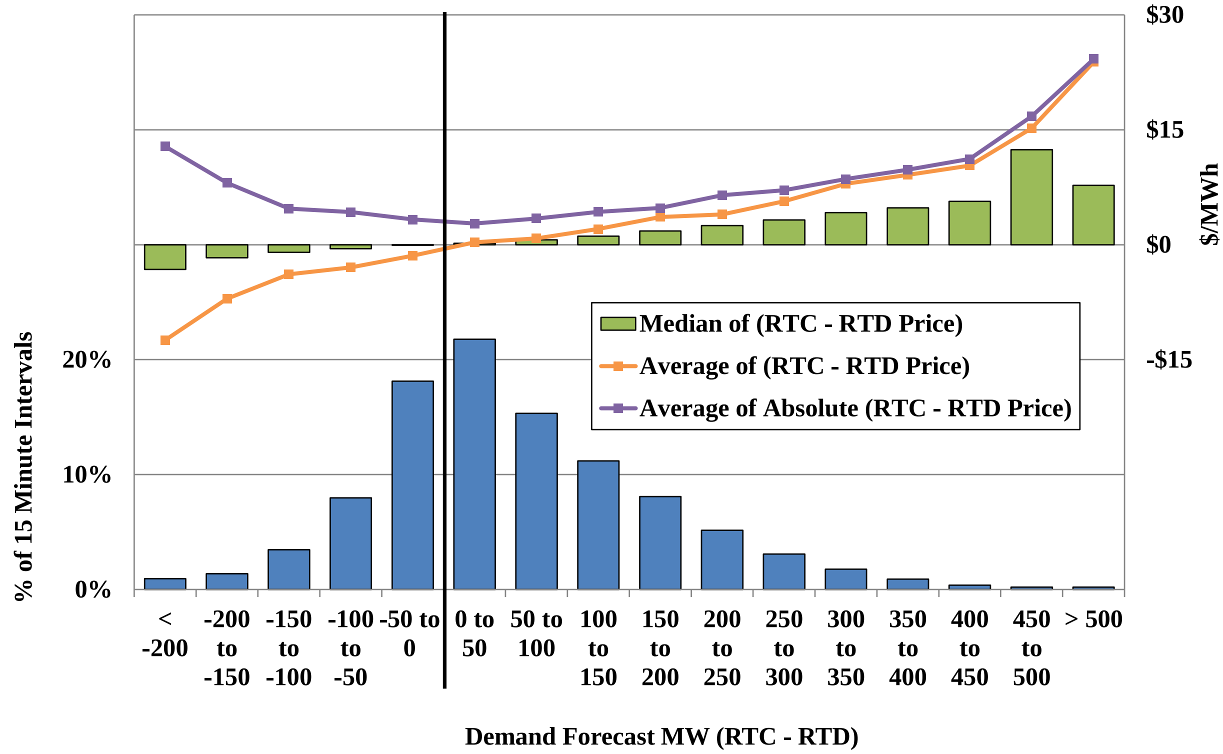


Figure A-70: Differences Between RTC and RTD Prices and Load Forecasts
by Time of Day, 2024

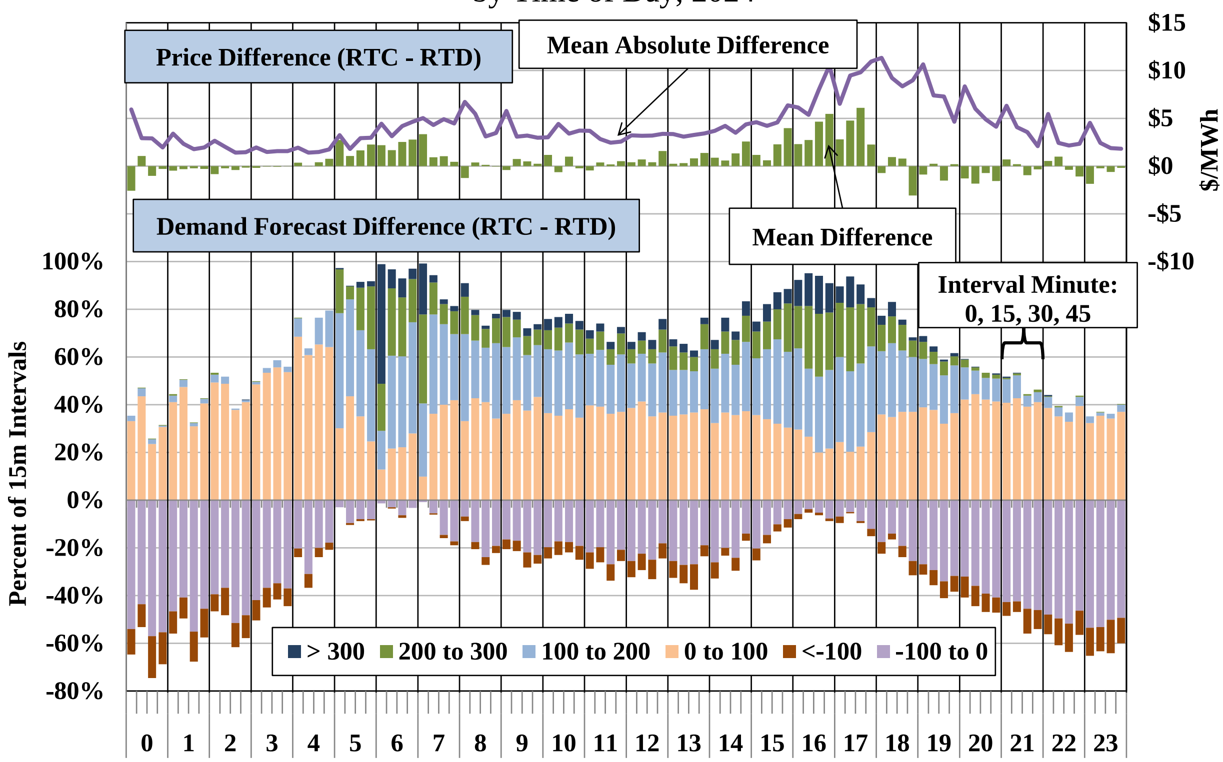


Figure A-71 & Figure A-72: Curtailments on RTC/RTD Divergence

Figure A-71 compares the frequency of external transaction curtailments by month in 2023 and 2024. This is shown separately for the Ontario interface, the Quebec interface, the primary New England interface, the Neptune interface, and the primary PJM interface. All other interfaces are grouped together. For one particular interface, one hour is counted towards the curtailment frequency if the quantity of net curtailments in either import direction or export direction was more than 100MW in any intervals within the hour.

Figure A-72 shows the 10 days in 2024 which contributed the most significant impact to the category of detrimental curtailments causing divergence between RTD and RTC. Of this category, the bulk of the impact (nearly 80 percent) is contained within the top 10 days.

Figure A-71: Number of Hours with External Transaction Curtailments by Interface
By Month, 2023-2024

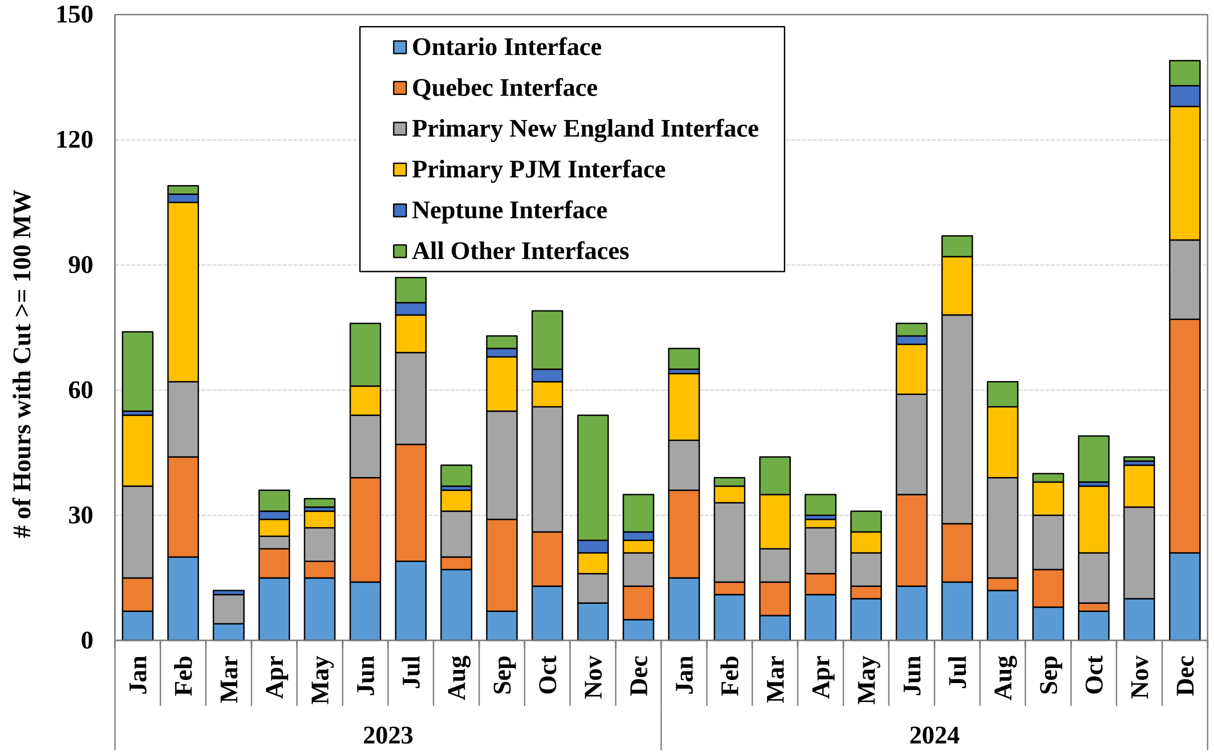
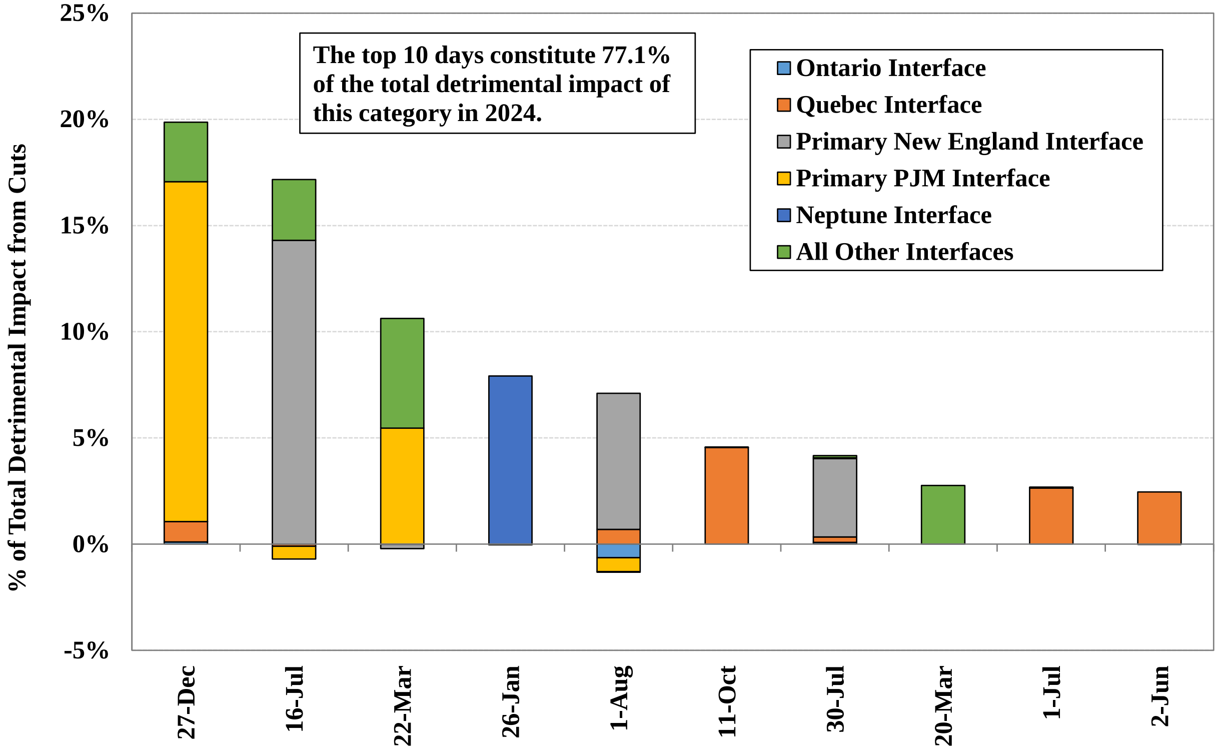


Figure A-72: Top 10 Days in Detrimental Curtailment Category
2024



V. MARKET OPERATIONS

The objective of the wholesale market is to coordinate resources efficiently to satisfy demand while maintaining reliability. The day-ahead market should commit the lowest-cost resources to meet expected conditions on the following day, and the real-time market should deploy the available resources efficiently. Clearing prices should be consistent with the costs of deploying resources to satisfy demand while maintaining reliability. Under shortage conditions, the real-time market should provide incentives for resources to help the NYISO maintain reliability and set clearing prices that reflect the shortage of resources.

The operation of the real-time market plays a critical role in the efficiency of the market outcomes because changes in operations can have large effects on wholesale market outcomes and costs. Efficient real-time price signals are beneficial because they encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable.

In this section, we evaluate the following aspects of wholesale market operations in 2024:

- *Real-Time Price-Setting by Gas Turbines with Multi-Hour Minimum Run Times* – This subsection evaluates the consistency of pricing with gas turbine commitment and dispatch decisions in the real-time market, focusing on a subset of gas turbines that offer multi-hour minimum run times.
- *Availability of Combined-Cycle Duct Burner Capacity in Real-Time Operations* – This subsection evaluates the availability of duct burner ranges on combined-cycles in real-time operations, highlighting its variability across different times and ambient conditions.
- *Dispatch Performance of Intermittent Generators when Curtailed* – This evaluates the performance of intermittent generators when operators curtail them for system security.
- *Performance of Operating Reserve Providers* – This subsection analyzes: a) the performance of gas turbines in responding to a signal to start-up in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.
- *M2M Coordination* – This subsection evaluates the operation of PAR-controlled lines under market-to-market coordination (“M2M”) between PJM and the NYISO.
- *Operation of Controllable Lines* – This subsection evaluates the efficiency of real-time flows across controllable lines more generally.
- *Regulation Movement-to-Capacity Ratio* – This subsection evaluates the actual movement-to-capacity for individual regulation providers versus the single common multiplier used in the regulation scheduling process.
- *Pricing Under Shortage Conditions* – We evaluate two types of shortage conditions: (a) shortages of operating reserves and regulation, and (b) transmission shortages.
- *Supplemental Commitment for Reliability* – Supplemental commitments are necessary when the market does not provide incentives for suppliers to satisfy certain reliability requirements. However, supplemental commitments raise concerns because they indicate

the market does not provide sufficient incentives, they dampen market signals, and they lead to uplift charges.

- *BPCG Uplift Charges* – This subsection evaluates BPCG uplift charges resulted primarily from supplemental commitment and out-of-merit dispatch.

A. Real-Time Price-Setting by Gas Turbines with Multi-Hour Minimum Run Times

The ISO schedules resources to provide energy and ancillary services using two models in real-time. First, the Real Time Dispatch model ("RTD") usually executes every five minutes, deploying resources that are flexible enough to adjust their output every five minutes. RTD also starts 10-minute units when it is economic to do so.[278] RTD models the dispatch across roughly a one-hour time horizon (rather than just the next five minutes), which better enables it to determine when a gas turbine will be economic to start or when a generator should begin ramping in anticipation of a constraint in a future interval.

Second, the Real Time Commitment model ("RTC") executes every 15 minutes, looking across a two-and-a-half hour time horizon. RTC is primarily responsible for scheduling resources that are not flexible enough to be dispatched by RTD. RTC starts-up and shuts-down 10-minute and 30-minute units when it is economic to do so.[279] RTC also schedules bids and offers to export, import, and wheel-through power to and from other control areas.

The real-time scheduling process ignores minimum run time offers and assumes a default one-hour minimum run time for all fast start units. Nonetheless, fast start units that submit bids with multi-hour minimum run times are excluded from setting prices. Therefore, the real-time costs of these units are not properly reflected in the LBMPs. This subsection evaluates the potential market impact from this discrepancy between scheduling and pricing in the real-time markets.

Figure A-73: Real-Time Prices during Commitment of GTs with Multi-Hour MRT

Figure A-73 evaluates prices during commitments of gas turbines offering multi-hour minimum run times in the real-time market in the past three years. The evaluation focuses on economic commitments made by RTC, RTD, or RTD-CAM,[280] excluding self-schedules and out-of-market commitments made by operators.

The bars in the figure show the total number of hours when GTs are economically committed each year. The blue bars indicate the number of hours when LBMPs exceeded GT costs (i.e., incremental cost + amortized startup cost), while the red bars represent the number of hours when LBMPs were below GT costs. The black line shows our estimate of potential price impact if these GTs were allowed to set prices. GTs are combined into seven groups in New York City and Long Island based on their electric connection to the grid.

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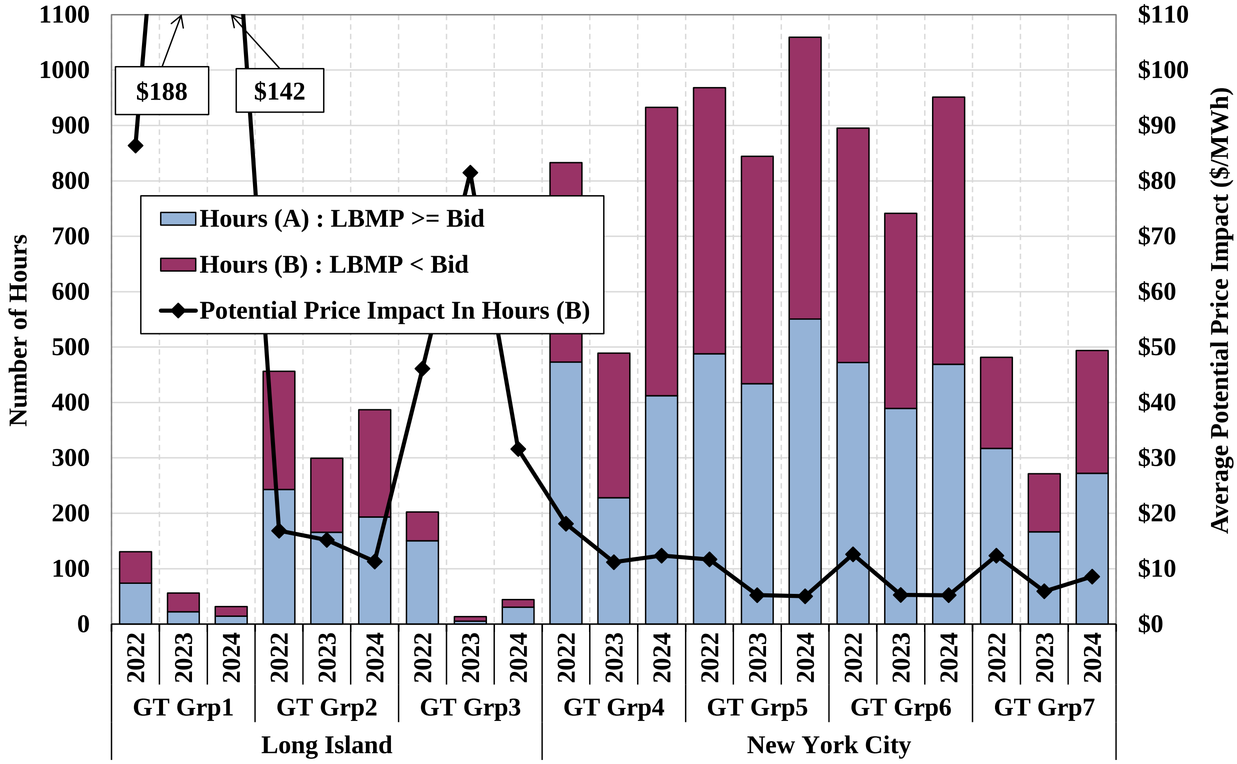
278 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

279 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

280 The Real-Time Dispatch – Corrective Action Mode (RTD-CAM) is version of RTD that NYISO operators can run on-demand to address abnormal or unexpected system conditions.

Figure A-73: Prices During Commitments of GTs Offering Multi-Hour Min Run Times
2022-2024



B. Availability of Combined-Cycle Duct Burners for Real-Time Operation

Most combined cycle units in New York have duct burners, which uses supplementary firing to increase the heat energy of a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. However, most duct-firing capacity is less capable of following a five-minute dispatch signal. The process of starting-up and shutting-down duct burners is similar to the start-up and shut-down of a fast-start unit. For this reason, some combined cycle units with a duct burner do not offer it into the real-time market, while others simply "self-schedule" this capacity in a non-dispatchable manner.

Table A-9 & Figure A-74 - Figure A-75: Combined-Cycle Unit Duct Burner Capacity and Availability in New York

Table A-9 summarizes the amounts of duct-firing capability in the summer and winter capability periods by load zone.

Figure A-74 shows an example of a combined-cycle unit that could not follow dispatch instructions during a Reserve Pickup ("RPU") event due to its inability to fire the duct burner within 10-minutes. However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software. This disconnect presents challenges in real-time operations when the duct-firing capacity becomes more valuable under tight system conditions like an RPU event.

Table A-9: Combined-Cycle Unit Duct Burner Capacity in New York
By Load Zone

Load Zone	# Generators (PTIDs)	Summer MW	Winter MW
West & Genesee	7	51	56.5
Central	7	38	39
North	3	31	31
MHK VL	2	13	15
Capital	10	209	189
HUD VL	5	174	179
NYC	7	280	312
Long Island	3	90	96
NYCA Total	**44**	**886**	**917**

In the figure, the two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes. The blue bars show the actual output produced by the resource in each RTD and RTD-CAM interval. The black dashed line shows the 5-minute instructions by the market model. The red-patterned area between the gray line and the instructed output line outlines the duct burner output that was not actually deliverable by the resource.

Figure A-74: Duct Burner Real-Time Dispatch Issue
Example of a Failed RPU

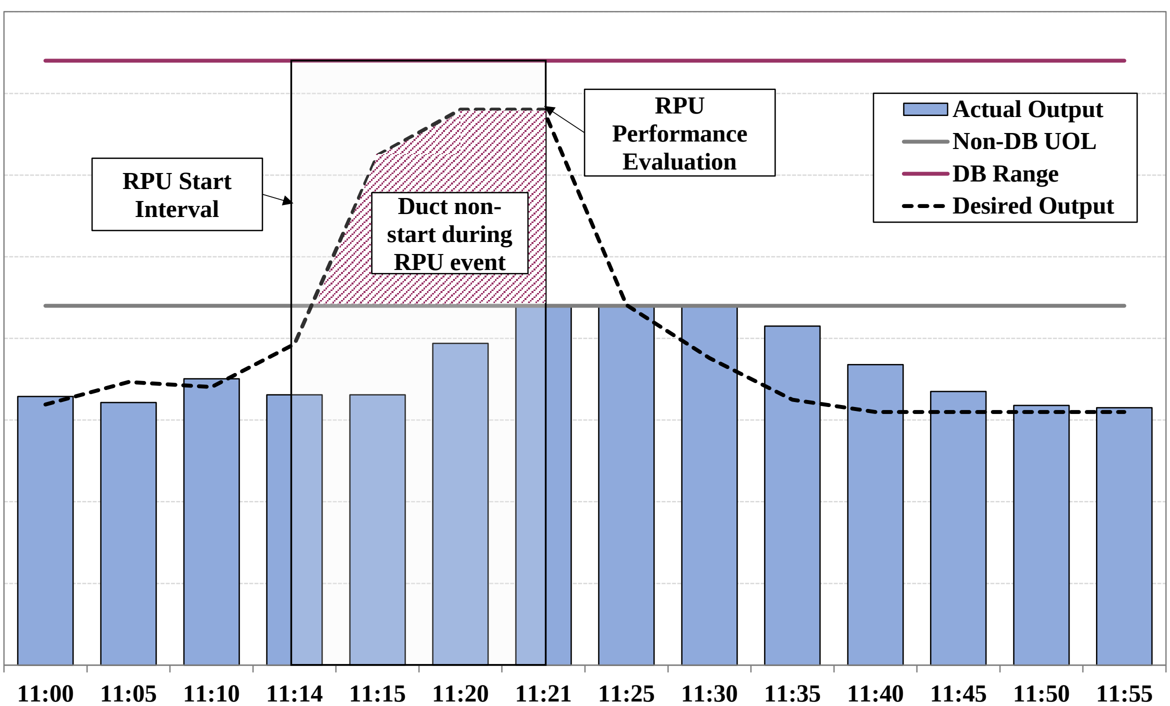


Figure A-75 examines duct burner availability in the real-time market for each quarter of 2024. The quantities in the charts are calculated for each 5-minute interval and then aggregated to the hourly level. The two charts on the left side show the amount of duct burner capacity scheduled or made available for scheduling within the timeframes that are unlikely deliverable for energy and reserves. These values show: (a) the average amount of MWs scheduled to provide 10-minute spinning reserves and regulation services; and (b) the amount of 5-minute up-ramping capability assumed to be available by duct burners.

The two charts on the right side show capacity that was not made available in offers for either energy and/or reserves from units with duct burners, including: (a) the average amount of duct burner capacity unavailable in real-time because of no offer in this range (labeled as 'Emergency MW' or non-dispatchable due to inflexible self-schedule level (labeled as 'Self-Fix MW'); and (b) the average amount of baseload capacity that was available but not offered for 10-minute and 30-minute reserves in real-time because the units were disqualified from offering these reserves.

Figure A-75: Evaluation of Duct-Burner Availability in Real-Time

2024

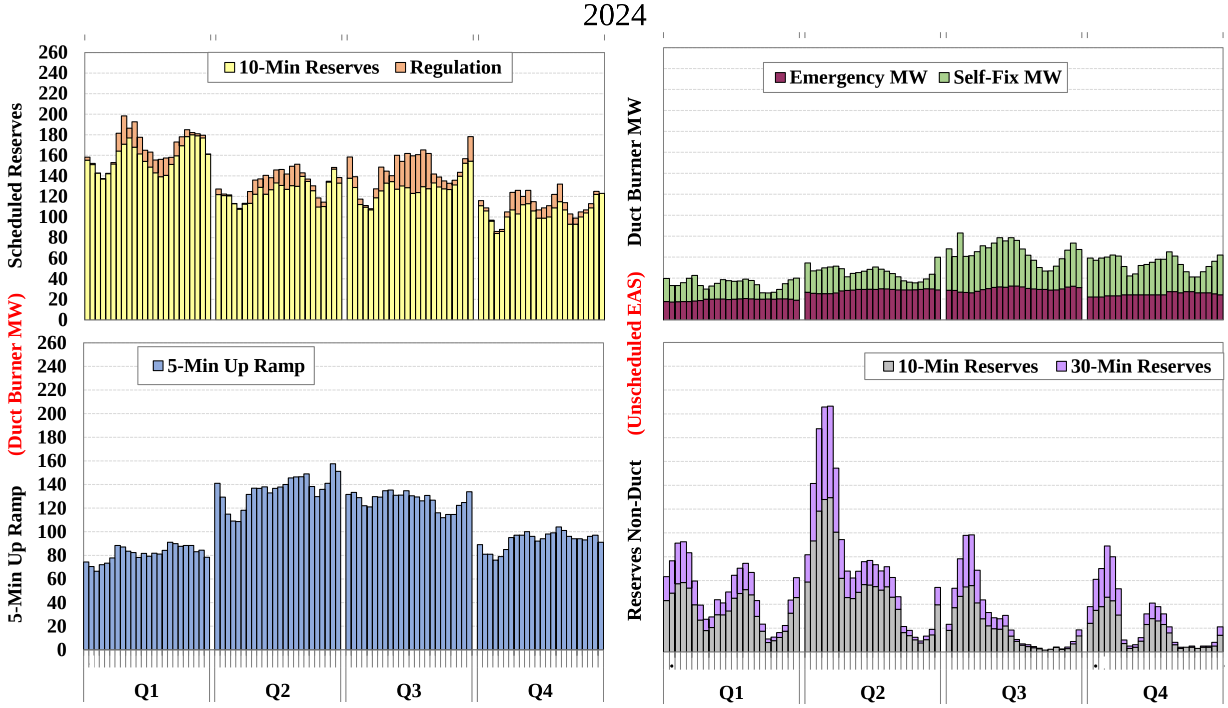


Figure A-76 & Figure A-77 – Ambient Impact on Duct Burner Availability Intraday

The NYISO Market Design project "Improve Duct Firing Modeling" seeks to ameliorate the modeling issues that render participation of duct burner capacity in the real-time markets onerous. The proposed approach allows participants to set a registration parameter to identify the output level at which the duct range begins and to the participation of these megawatts in the 10-minute reserve product.[281] The objective is twofold:

- Remove duct burner capacity from participation as 10-minute reserve capacity, and
- Allow for lower ramp rates in that range that better reflect the physical limitations of the duct burners.

281 See slide 11 on presentation.

While this change should reduce the amount of 10-minute reserves that the NYISO schedules from generators with duct burners, the physical point at which this range begins is highly variable daily and even hourly due to the effects of ambient conditions on generator capability. Figure A-76 illustrates how the duct firing range of a typical combined cycle generator varied hourly across a typical summer month (June 2023).

- The solid black line shows the hourly Upper Operating Limit ("UOL") of the example generator taken from the day-ahead ("DA") bids across each day of June 2023.
- The dashed black line shows the hourly UOL of the generator excluding the duct range, i.e., the UOL of the unit minus its reported duct firing capability.
- The shaded blue region shows the capacity associated with the duct burner range. It is assumed that the duct range will be utilized last due to the higher fuel and maintenance costs of firing in that range.

All capacity values are shown as ratios to the Summer DMNC for the example unit. For example, it is often the case that a combined cycle will offer a higher UOL than its DMNC due to ambient conditions, especially in the early parts of the summer or in the off-peak hours. Thus, the total UOL may be 110-percent of DMNC with the non-duct burner range ending at 100-percent of DMNC.

Figure A-76: Illustration of Duct Burner Range

Example Generator Hourly Capability

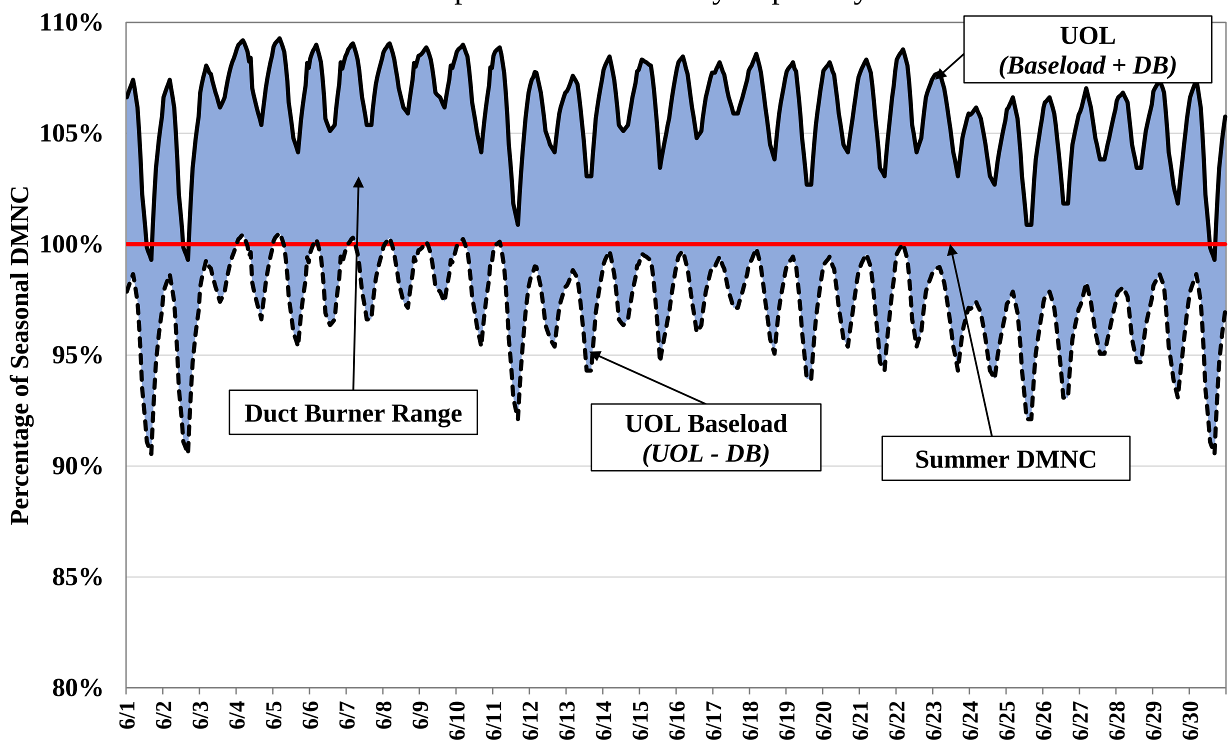


Figure A-77 displays how the availability of the duct burner range may be mischaracterized by static ramp rate ranges even when market participants actively adjust this parameter through the registration process. The figure shows the following two hourly average quantities:

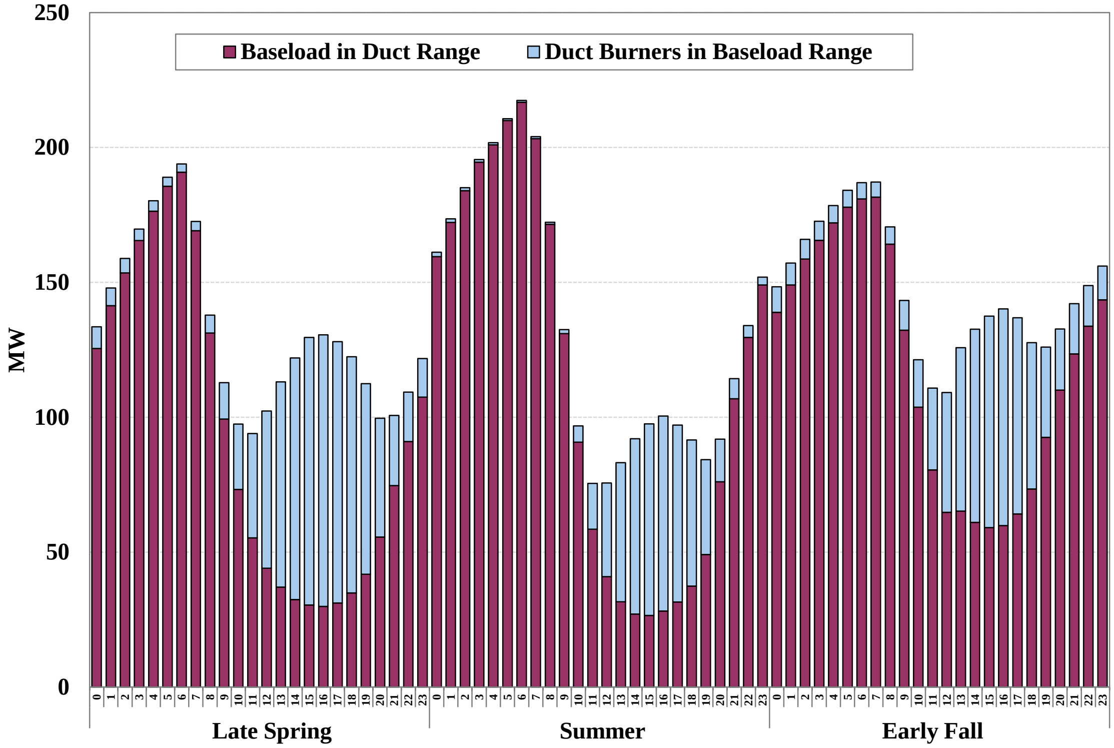
- Baseload capacity that could be mischaracterized as being in the duct burner range, and
- Duct Burner capacity that could be mischaracterized as being in the baseload range.

These quantities are shown for three periods across the Summer 2023 Capability Period:

- *Late Spring:* includes the months of May and June;
- *Summer:* includes the months of July and August; and
- *Early Fall:* includes the months of September and October.

This analysis assumes that the market participants actively manage their resources and update the registration parameter for the duct burner range twice a week (Monday and Thursday) based on the average temperature recorded at the generator site over the previous three or four days. The estimates of the two quantities in the chart are based on the output factor equations established for individual combined cycle units and their onsite hourly temperatures.[282] The results in the chart show how much capacity on average could be mischaracterized for combined cycle generators with duct burners.

Figure A-77: Hourly Limitations of Administering Static Duct Burner Ranges



282 Output factor equations are used for ambient temperature dependent generators, which include combined cycle units, to estimate their upper operating limits based on ambient air temperatures. Refer to Attachment M of the ICAP Manual for further information.

C. Dispatch Performance of Intermittent Power Resources during Curtailments

Table A-10 displays the performance of wind-and-solar powered Intermittent Power Resources ("IPRs") in 2024 when receiving an Output Limit (i.e., being curtailed). Each such resource is placed into a performance range based on how much it actually reduced output during economic curtailments in 2024. Performance is measured as one minus the sum of overgeneration divided by expected curtailment by resource during all RTD intervals when an RTD Output Limit was imposed. Overgeneration is calculated as the maximum of zero and the difference between the generator's actual output and its economic basepoint plus 3-percent of its Upper Operating Limit ("UOL"). Expected curtailment is estimated based on the difference between the generator's economic basepoint and its RTD forecasted output.[283] Performance metrics are then calculated as one minus the total annual overgeneration divided by the total annual expected curtailment value.

Table A-10: Performance of IPRs during Economic Curtailment
2024

Performance Range	No. of Units	Percent of ICAP
0% to 10%	0	0.0%
10% to 20%	3	8.7%
20% to 30%	2	1.1%
30% to 40%	0	0.0%
40% to 50%	0	0.0%
50% to 60%	2	7.7%
60% to 70%	3	9.7%
70% to 80%	5	12.3%
80% to 90%	10	16.8%
90% to 100%	19	43.7%

While most intermittent generators comply well with curtailment instructions and most curtailment instructions are given to the good performing resources, a small number of generators perform significantly worse than average. Figure A-78 shows the performance of one wind resource that did not respond appropriately during a January 2024 event. Since this unit did not respond to Output Limits, the operators were forced to issue manual curtailment instructions to other nearby wind units to maintain transmission security. The primary axis shows total generation from the non-compliant unit broken into two categories:

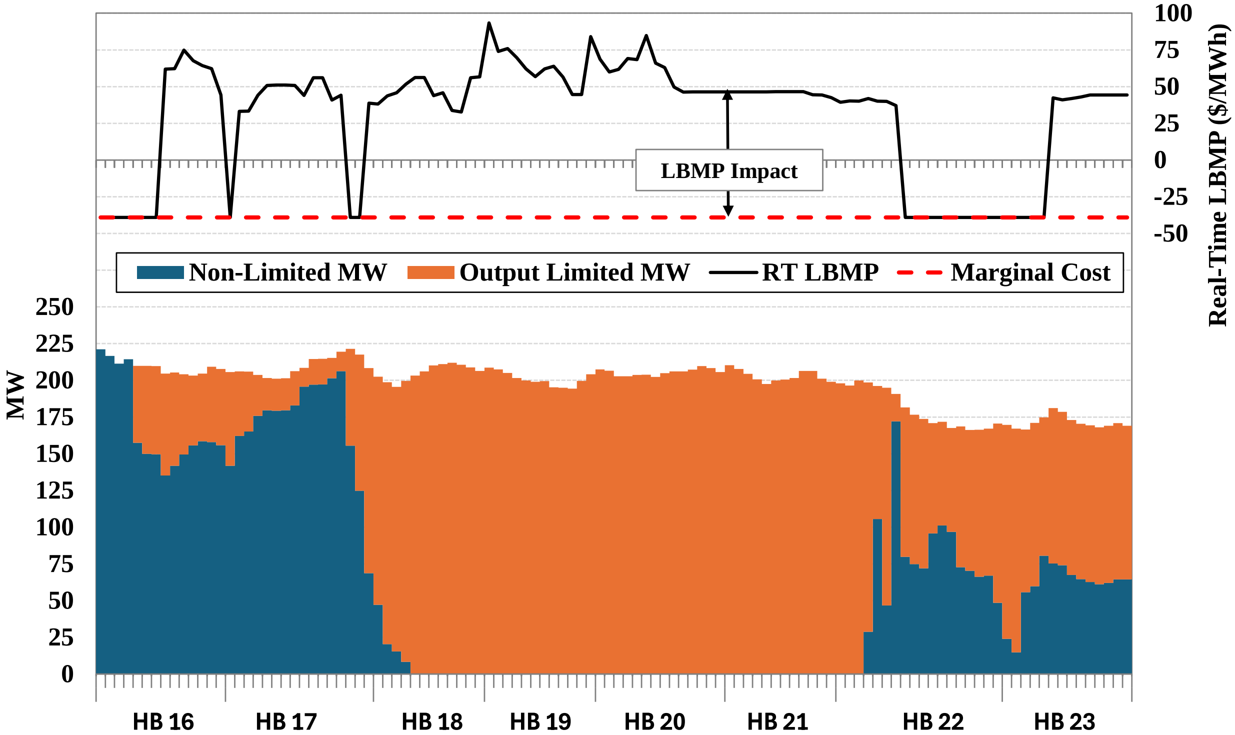
- The actual output from the unit that would have been produced even if it had followed its Output Limit (blue columns), and
- The actual output from the unit that would have been curtailed if the resource had followed its Output Limit (orange columns).

283 The economic basepoint is driven by the Output Limit whereas the RTD forecast output is not constrained by the curtailment instruction. Therefore, the RTD forecast output gives an approximate value of the capability of the IPR in the absence of an Output Limit.

The amount of curtailment megawatts that would have applied to the unit were calculated based on the amount of output curtailed manually by operators from other IPRs and adjusted based on the shift factors from all relevant units on the active constraint. The secondary axis shows the real-time nodal LBMP (black line) at the non-responding IPR along with an estimate of its marginal cost (red dashed line). Whenever these two lines diverge, it indicates that the magnitude of the manual curtailments issued by the NYISO caused the constraint to not bind in the real-time market.

Figure A-78: Failure to Follow Curtailment Instructions

Event where IPR Did Not Respond to Output Limits, January 2024



The following summarizes the overgeneration penalties for intermittent generators that do not obey curtailment instructions.

Explanation of Overgeneration Charge Shortcoming

When the real-time LBMP is negative, as is usually the case during an interval with an Output Limit, the NYISO balancing settlement is determined based on the following simplified formula:[284]

$$(E_{RT} - E_{DA}) * LBMP_{RT} + P$$

Where:

E_{RT} = Real-time Actual Output in MW from the resource

E_{DA} = Day-ahead scheduled Output in MW from the resource

284 See B.2 of the Accounting and Billing Manual.

$LBMP_{RT}$ = Real-time LBMP

P = Overgeneration Charge which is 0 if the Actual Output is less than or equal to the Basepoint plus 3% of UOL.[285]

However, the resource will also receive compensation based on state Renewable Energy Certificates ("RECs") and federal production tax credits ("PTC") for the actual output that it produces. This means that the true balancing settlement to the resource, including both the NYISO settlement and the production credits is:

$$(E_{RT} – E_{DA}) * LBMP_{RT} + (E_{RT} * CREDIT) + P$$

Where CREDIT is the sum of the value per MWh of the applicable PTC and RECs to the resource.

When the IPR fails to follow dispatch, its actual output exceeds the economic basepoint ("E_{BP}") to which the model instructs it, i.e., $E_{RT} > E_{BP}$. The change in settlements to the resource from all sources can be described as:

$$\{(E_{RT} – E_{DA}) * LBMP_{RT} + (E_{RT} * CREDIT) + P\} – \{(E_{BP} – E_{DA}) * LBMP_{RT} + (E_{BP} * CREDIT)\}$$

Which is equal to:

$$(E_{RT} – E_{BP}) * (LBMP_{RT} + CREDIT) + P$$

This equation will yield a positive value if (CREDIT + $LBMP_{RT}$) > P. Therefore, if the resource's LBMP is set at a price above its short-run marginal cost (= -1 * CREDIT) by an amount greater than the value of the overgeneration charge, i.e., the maximum of the day-ahead and real-time regulation capacity charge, it stands to benefit from ignoring an Output Limit instruction. If the LBMP is similar to the short-run marginal cost, the IPR has a weak disincentive to over-generate by more than 3% of its UOL. If the LBMP is much higher than its short-run marginal cost (as occurred in the event summarized in Figure A-78), then the IPR will profit significantly by not complying with curtailment instructions.

D. Performance of Operating Reserve Providers

Wholesale markets should provide efficient incentives for resources to help the ISO maintain reliability by compensating resources consistent with the value they provide. This subsection evaluates: a) the performance of GTs in responding to start-up instructions in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.

Table A-11: Average GT Performance after a Start-Up Instruction

Table A-11 summarizes the performance of offline GTs in responding to start-up instructions that result from NYISO audits and economic commitments (including commitments by RTC,

[285] The overgeneration charge is based on the maximum of the day-ahead and real-time regulation capacity price for the impacted intervals.

RTD, and RTD-CAM).[286] The table's rows categorize performance into 10-percent increments from 0 to 100 percent. A unit's performance for a given start is measured based on its output level at its expected full output time (i.e., at 10 or 30 minutes after receiving a start-up instruction), expressed as a percentage of its Upper Operating Limit ("UOL"). For example, if a 40 MW 10-minute GT produces 30 MW at the 10-minute mark after receiving a start-up instruction, its performance is 75 percent, which falls into the 70-to-80-percent category. The performance category represents a unit's average performance across all economic starts and NYISO audits in 2024. For each performance category, the table shows:

- Number of Units;
- Total Number of Associated Unit-Starts;
- Average Performance On Time: measured at the unit's expected full output time; and
- Average Performance 10 Minute Later.

Performance metrics are also broken down for two different operating conditions:

- **RPUs + Unforeseen Economic Starts & Audits:** These include Reserve Pickup ("RPU") events, random NYISO audits, and economic starts that are *NOT* anticipated in the look-ahead advisory evaluations.
- **Remaining Economic Starts and Audits:** These include re-tests conducted within days after an initial audit failure and economic starts that are anticipated in the look-ahead advisory evaluations.

Table A-11: Average GT Performance After a Start-up Instruction
2024

10/30-Minute GT Start Performance - 2024						
Performance Category	No. of Units	Total No. of Starts Evaluated	RPUs + Unforeseen Economic Starts and Audits		Remaining Economic Starts and Audits	
			Performance On Time	Performance 10 Min Later	Performance On Time	Performance 10 Min Later
0% - 10%	0	0				
10% - 20%	0	0				
20% - 30%	0	0				
30% - 40%	1	15	35.3%	54.9%		
40% - 50%	1	8	46.3%	50.0%		
50% - 60%	1	13	42.3%	70.2%	85.0%	96.8%
60% - 70%	3	134	66.4%	78.2%	64.2%	83.0%
70% - 80%	2	14	50.7%	65.3%	97.2%	86.5%
80% - 90%	24	2807	83.4%	95.0%	86.8%	95.0%
90% - 100%	72	7082	96.0%	97.9%	94.0%	97.5%

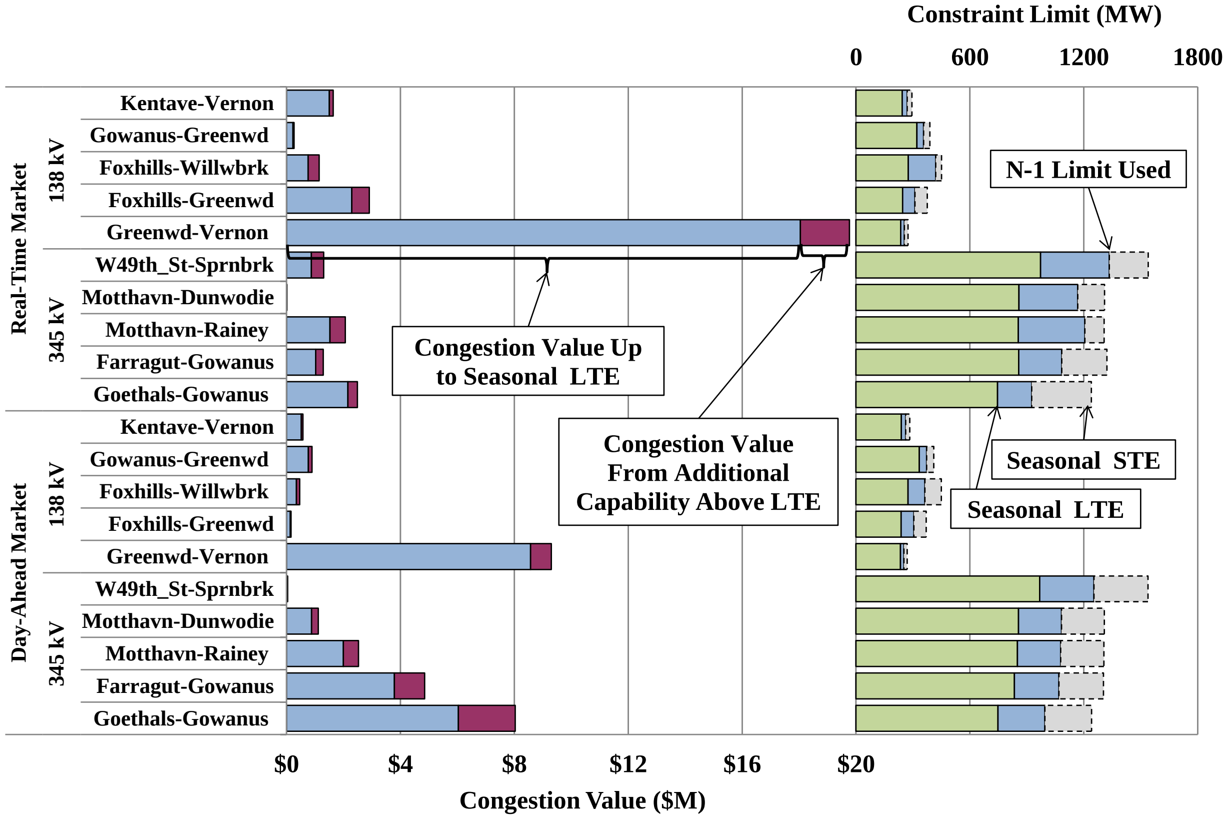
286 This evaluation does not include OOM start-ups by either NYISO or TO as we do not have reliable data for the instructed starting times.

Figure A-79: Use of Operating Reserves to Manage Congestion in New York City

The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE. The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs. However, the service provided by these actions are not properly compensated.

Figure A-79 shows such select N-1 constraints in New York City. The left panel in the figure summarizes their day-ahead and real-time congestion values in 2024. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[287] The red bars represent the congestion values measured for the additional transfer capability above LTE.[288] The bars in the right panel show the average seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.

Figure A-79: Use of Operating Reserves to Manage N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings, 2024



287 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

288 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

E. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") commenced in January 2013. This process allows each RTO to relieve congestion more efficiently on its constraints with re-dispatch from the other RTO's resources when it is less costly for them to do so.[289] M2M includes two types of coordination:

- Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.

- PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, three sets of PAR-controlled lines between New York and New Jersey can be adjusted to reduce overall congestion.[290]

Ramapo PARs have been used for the M2M process since its inception, while ABC and JK PARs were incorporated into this process later in May 2017 following the expiration of the ConEd-PSEG Wheel agreement. The NYISO and PJM have an established process for identifying constraints that will be on the list of pre-defined flow gates for Re-dispatch Coordination and PAR Coordination.[291]

Figure A-80: NY-NJ PAR Operation under M2M with PJM

The use of Re-dispatch Coordination has been infrequent since the inception of M2M, while the use of PAR Coordination had far more significant impacts on the market. Hence, the following analysis focuses on the operation of NY-NJ PARs in 2024.

Figure A-80 evaluates operations of these NY-NJ PARs under M2M with PJM during periods of noticeable congestion differential between NY and PJM. For each PAR group in the figure, the evaluation is done for the following periods:

- When NY costs on relevant M2M constraints exceed PJM costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh.

- When PJM costs on relevant M2M constraints exceed NY costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh;

The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over

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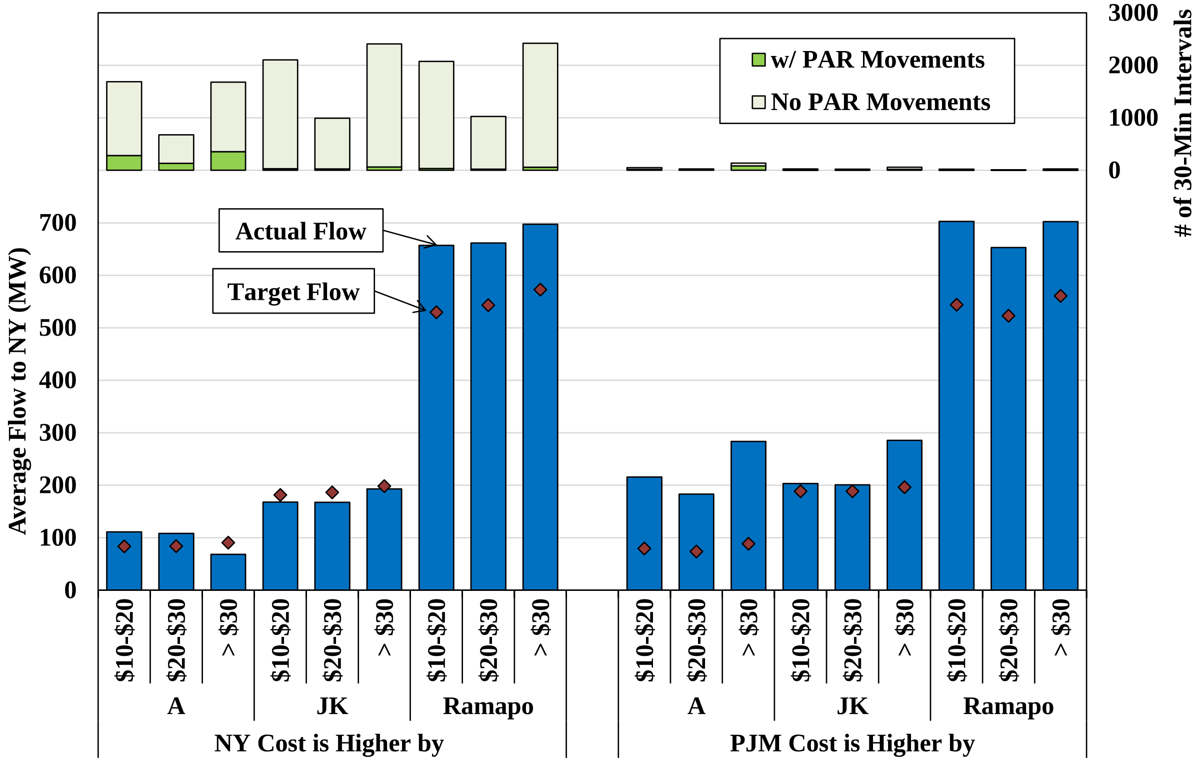
289 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

290 These include two Ramapo PARs that control the 5018 line, three Waldwick PARs that control the J and K lines, and one PAR that controls the A line.

291 The list of pre-defined flowgates, *Coordinated Flowgates and Entitlements*, is posted here in the subgroup "Notices" under "General Information".

each half-hour period. In the figure, the top portion shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements; while the bottom portion shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

Figure A-80: NY-NJ PAR Operation under M2M with PJM
2024



F. Operation of Controllable Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows below applicable limits. However, there are still a significant number of controllable transmission lines that source and/or sink in New York. This includes HVDC transmission lines, PAR-controlled lines, and VFT-controlled lines. Controllable transmission lines allow power flows to be channeled along paths that lower the overall cost of satisfying the system's needs. Hence, they can provide greater benefits than conventional AC transmission lines.

Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways. First, some controllable transmission lines are scheduled as external interfaces using external transaction scheduling procedures.[292] Such lines are analyzed in Section V.F of the Appendix,

292 This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), and the Linden VFT Scheduled Line.

which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted by the local TO to reduce generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not primarily focused on reducing production costs in the day-ahead and real-time markets. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-12 & Figure A-81: Scheduling of Non-Optimized PAR-Controlled Lines

PARs are commonly used to control line flows on the bulk power system. Through control of tap positions, power flows on a PAR-controlled line can be changed to facilitate power transfer between regions or to manage congestion within and between control areas. This subsection evaluates efficiency of PAR operations during 2024.

Table A-12 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2024. The evaluation is done for the following eight PAR-controlled lines:

- One between IESO and NYISO: St. Lawrence – Moses PAR (L34 line).
- One between ISO-NE and NYISO: Sand Bar – Plattsburgh PAR (PV20 line).
- Four between PJM and NYISO: Two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), and one Linden-Goethals PAR (A line). These are discussed in sub-section E.
- Two between Long Island and New York City: Lake Success-Jamaica PAR (903 line) and Valley Stream-Jamaica PAR (901 line), which are usually scheduled to support a wheel of up to 300 MW from upstate New York through Long Island to New York City.

For each group of PAR-controlled lines, Table A-12 shows:

- Average hourly net flows into NYCA or New York City;
- Average price at the interconnection point in the NYCA or NYC minus the average price at the interconnection point in the adjacent area (the external control area or Long Island);
- The share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-price market); and
- The estimated production cost savings that result from the flows across each line. The estimated production cost savings in each hour is based on the price difference across the line multiplied by the scheduled power flow across the line.[293]

[293] For example, if 100 MW flows from Lake Success to Jamaica in one hour, the price at Lake Success is $50 per MWh and the price at Jamaica is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10) because each MW of flow saves $10 by allowing a $60 per MWh resource in New York City to ramp down and a $50 per MWh resource in Long Island to ramp up. This method tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production

This analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[294] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market. The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market.

Table A-12: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2024

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					6	$5.85	52%	$0.8
New England to NYCA								
Sand Bar	-80	-$8.68	76%	$6	0	-$8.26	55%	$0.4
PJM to NYCA								
Waldwick	149	$5.95	86%	$6	-84	$3.57	46%	-$0.9
Ramapo	508	$10.52	93%	$46	63	$9.27	63%	$5
Goethals	74	$9.25	91%	$8	27	$9.40	54%	-$3.8
Long Island to NYC								
Lake Success	39	-$3.12	19%	-$1	-3	-$2.81	50%	$0.2
Valley Stream	35	-$2.92	22%	-$1	3	-$3.77	41%	-$0.2

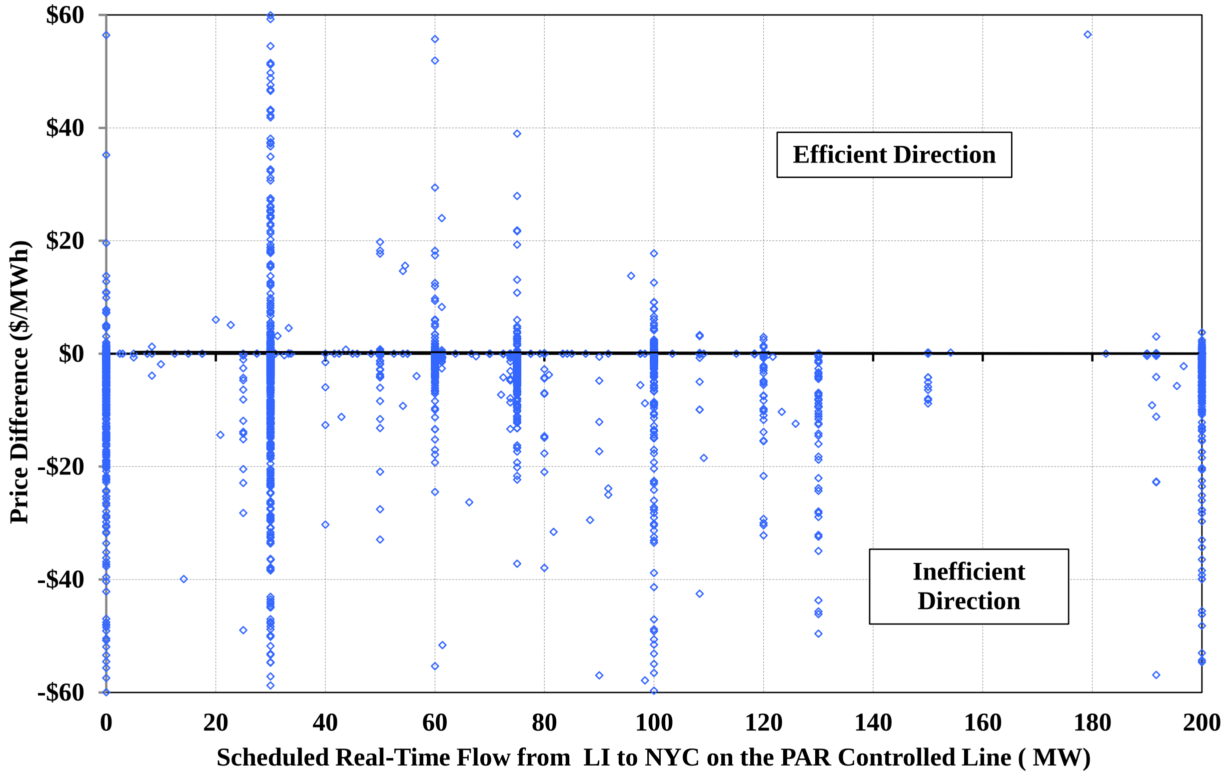
* The estimated production cost savings tend to: 1) under-estimate actual savings when power flows from the low-priced region to the high-priced region, since if flows were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall; while 2) over-estimate actual cost increases when power flows from the high-priced region to the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

Figure A-81 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake Success-Jamaica line. The figure shows hourly price differences in the real-time market on the vertical axis versus power flows scheduled in the real-time market on the horizontal axis. Points above the $0-dollar line in the figure are characterized as scheduled in the efficient direction. Power scheduled in the efficient direction flows from the lower-priced market to the higher-priced market. Similarly, points below the $0-dollar line are characterized as scheduled in the inefficient direction, corresponding to power flowing from the higher-priced market to the lower-priced market. Good market performance would be indicated by a large share of hours scheduled in the efficient direction.

cost increases when power flows from high-priced region towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

294 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule is considered *efficient direction*, and if the relative prices of the two regions is switched in the real-time market and the flow was reduced to 80 MW, the adjustment is shown as -20 MW and the real-time schedule adjustment is considered *efficient direction* as well.

Figure A-81: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2024



G. Regulation Movement-to-Capacity Ratio

Regulation sellers submit a two-part offer indicating two separate costs of providing regulation services. One is the capacity offer indicating the cost associated with setting aside capacity for regulation. The other is the movement offer that indicates additional cost associated with moving the resource up and down every six seconds when deployed to provide regulation. Under the current market rules, a composite offer is calculated equal to (*capacity offer*) plus (*movement offer*) times (*movement multiplier*) for each regulation provider that estimates its overall cost of providing regulation and is used in the market software for scheduling and pricing.

Resources are currently scheduled assuming a uniform Regulation Movement Multiplier of 8 per MW of capability,[295] but they are deployed based on individual ramping capability and are compensated according to actual movement. This inconsistency between assumed costs and actual costs incurred can lead to inefficiency in the resource scheduling and pricing. This subsection focuses on actual regulation movement versus assumed common multiplier.

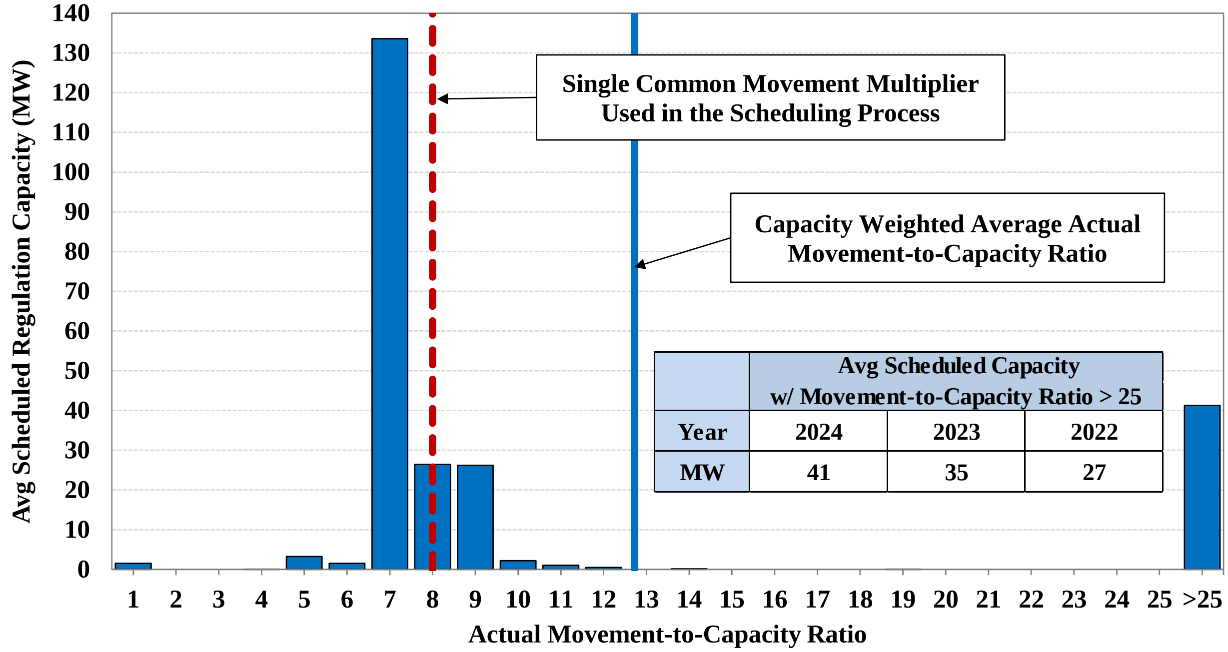
Figure A-82 & Figure A-83: Regulation Movement-to-Capacity Ratio

Figure A-82 shows a distribution of average actual movement-to-capacity ratio of all scheduled regulation suppliers in 2024. The blue bars show the average scheduled regulation capacity in

295 The uniform Regulation Movement Multiplier was changed from 13 to 8 on August 31, 2021.

each movement-to-capacity ratio. The solid blue line represents the capacity weighted average actual movement-to-capacity ratio, compared to the multiplier of 8 that is currently used for all resources when formulating the composite regulation offer.

Figure A-82: Distribution of Actual Regulation Movement-to-Capacity Ratio
2024



	Avg Scheduled Capacity w/ Movement-to-Capacity Ratio > 25		
Year	2024	2023	2022
MW	41	35	27

Figure A-83: Regulation Requirement and Movement-to-Capacity Ratio
By Month, 2022-2024

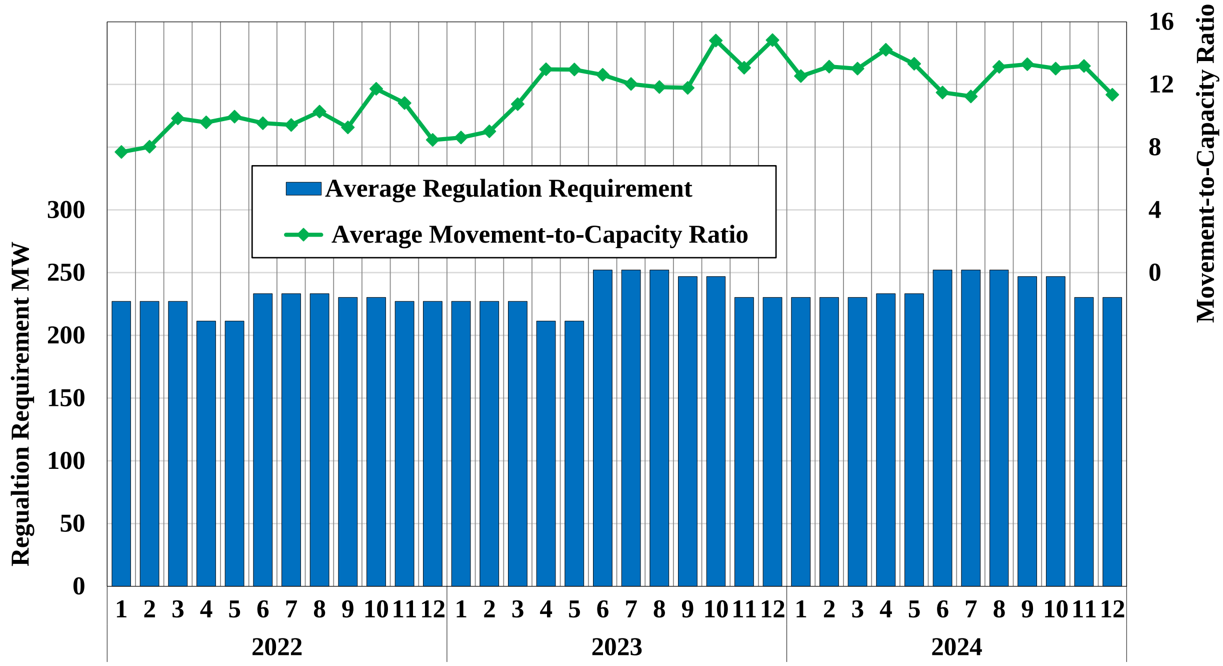


Figure A-83 tracks the variation of regulation movement-to-capacity ratio in recent years, summarizing the following quantities by month:

- Average regulation requirement – The regulation requirement varies by hour by season. This is the hourly average regulation requirement for each month.
- Average actual regulation movement-to-capacity ratio – This is calculated as total regulation movement MW from all resources divided by total scheduled regulation capacity in each month.

H. Market Operations under Shortage Conditions

Prices that occur under shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves and regulation needs of the system while satisfying transmission security constraints) are an important contributor to efficient price signals. In the long-run, prices should signal to market participants where and when new investment in generation, transmission, and demand response would be most valuable to the system. In the short-run, prices should provide market participants with incentives to commit sufficient resources in the day-ahead market to satisfy anticipated system conditions the following day, and prices should give suppliers and demand response resources incentives to perform well and improve the reliability of the system, particularly during real-time shortages. However, it is also important that shortage pricing only occurs during legitimate shortage conditions rather than as the result of anticompetitive behavior or inefficient market operations.

The importance of setting efficient real-time price signals during shortages has been well-recognized. Currently, there are three provisions in NYISO's market design that facilitate shortage pricing. First, NYISO uses operating reserves and regulation demand curves to set real-time clearing prices during operating reserves and regulation shortages. Second, NYISO uses a transmission demand curve to set real-time clearing prices during a portion of transmission shortages. Third, NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the deployment of demand response.

In this section, we evaluate the operation of the market and resulting prices when the system is in the following two types of shortage conditions in 2024:

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection I).

Figure A-84: Real-Time Prices During Physical Ancillary Services Shortages

NYISO's approach to efficient pricing during operating reserves and regulation shortages is to use ancillary services demand curves. The real-time dispatch model ("RTD") co-optimizes the procurement of energy and ancillary services, efficiently allocating resources to provide energy and ancillary services every five minutes. When RTD cannot satisfy both the energy demand and ancillary services requirements with the available resources, the demand curves for ancillary services rationalize the pricing of energy and ancillary services during shortage periods by causing prices to reflect the value of foregone ancillary services. The demand curves also set limits on the costs that can be incurred to maintain operating reserves and regulation.

Figure A-84 summarizes physical ancillary services shortages and their effects on real-time prices in 2023 and 2024 for the following eight categories: [296]

- 30-minute NYCA – The ISO is required to hold 2,620 MW of 30-minute reserves in the state and has a demand curve value of $40/MW if the shortage is up to 200 MW, $100/MW if the shortage is between 200 and 325 MW, $175/MW if the shortage is between 325 and 380 MW, $225/MW if the shortage is between 380 and 435 MW, $300/MW if the shortage is between 435 and 490 MW, $375/MW if the shortage is between 490 and 545 MW, $500/MW if the shortage is between 545 and 600 MW, $625/MW if the shortage is between 600 and 655 MW, and $750/MWh if the shortage is more than 655 MW.
- 10-minute NYCA – The ISO is required to hold 1,310 MW of 10-minute operating reserves in the state and has a demand curve value of $750/MW.
- 10-Spin NYCA – The ISO is required to hold 655 MW of 10-minute spinning reserves in the state and has a demand curve value of $775/MW.
- 10-minute East – The ISO is required to hold 1200 MW of 10-minute operating reserves in Eastern New York and has a demand curve value of $775/MW.
- 30-minute SENY – The ISO is required to hold at least 1300 MW of 30-minute operating reserves in Southeast New York for all hours and has a demand curve value of $500/MW. Additional 30-minute operating reserves are required for a subset of hours and has a demand curve value of $40/MW in the incremental range.
- 10-minute NYC – The ISO is required to hold 500 MW of 10-minute operating reserves in New York City and has a demand curve value of $25/MW.
- 30-minute NYC – The ISO is required to hold 1000 MW of 30-minute operating reserves in New York City and has a demand curve value of $25/MW.
- Regulation – The ISO is required to hold 150 to 300 MW of regulation capability in the state and has a demand curve value of $25/MW if the shortage is less than 25 MW, $525/MW if the shortage is between 25 and 80 MW, and $775/MW if the shortage is more than 80 MW.

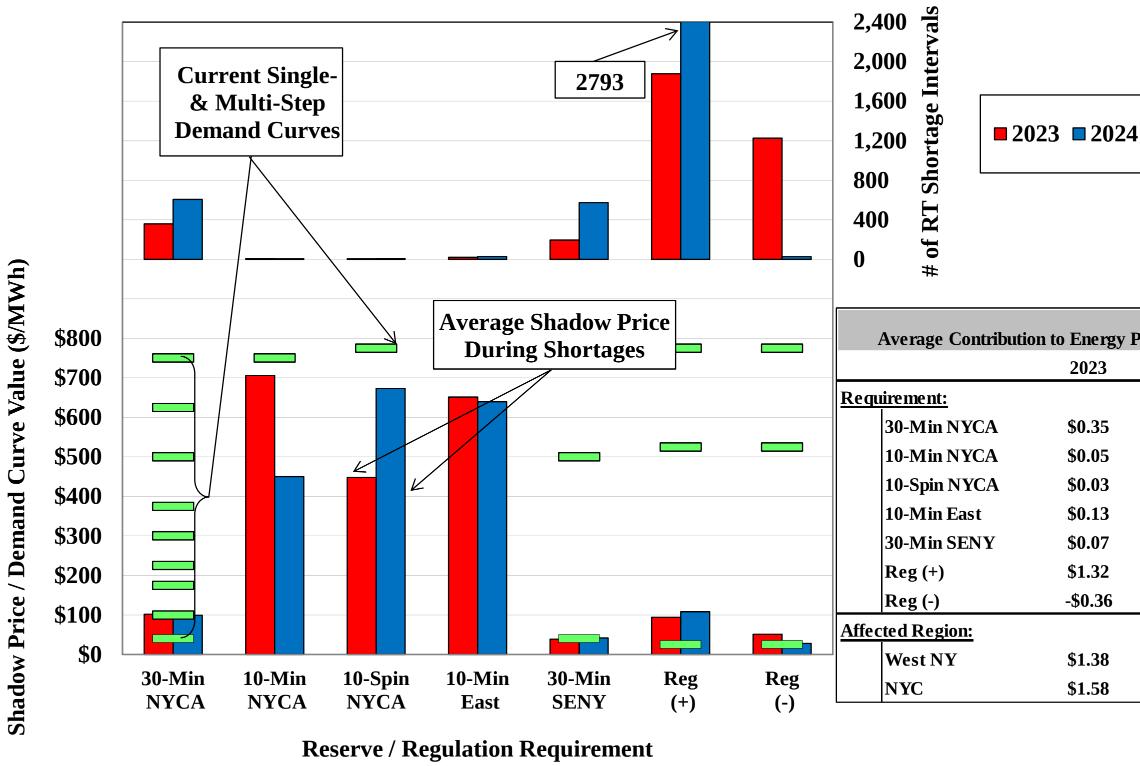
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency of shortages, indicating the overall price impact of the shortages by product and in total by region. The table also shows the cumulative effect of all ancillary services shortages on average real-time energy clearing prices in:

- Western New York – This is based on the sum of shadow prices of the NYCA reserve requirements as well as the effects of positive and negative regulation spikes; and
- Eastern New York (outside New York City) – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

296 See *NYISO Ancillary Services Manual* for more details.

- New York City – This equals the Eastern New York effect plus the sum of shadow prices of SENY and New York City reserve requirements.

Figure A-84: Real-Time Prices During Ancillary Services Shortages
2023 – 2024



Average Contribution to Energy Price	2023	2024
Requirement:		
30-Min NYCA	$0.35	$0.57
10-Min NYCA	$0.05	$0.02
10-Spin NYCA	$0.03	$0.04
10-Min East	$0.13	$0.18
30-Min SENY	$0.07	$0.23
Reg (+)	$1.32	$2.33
Reg (-)	-$0.36	$0.00
Affected Region:		
West NY	$1.38	$2.96
NYC	$1.58	$3.36

Figure A-85 & Table A-13: Reserves Shortages in New York City

NYISO currently models two reserves requirements in NYC:

- 10-minute Reserves Requirement – The ISO is required to hold 500 MW of 10-minute operating reserves in New York City and has a demand curve value of $25/MWh; and
- 30-minute Reserves Requirement – The ISO is required to hold 1,000 MW of 30-minute operating reserves in New York City and has a demand curve value of $25/MWh.

Table A-13 shows the real-time market performance during reserves shortages in New York City for each month in 2024. The table shows the following quantities:

- # Intervals – This is the total number of real-time intervals in each month when either 10-minute reserves or 30-minute reserves or both were short in New York City.
- Average Shortage MW – This is the average quantity of reserve shortages over all shortage intervals in each month. In each interval, the shortage quantity is equal to the higher amount of 10-minute and 30-minute shortages.
- # Intervals with 'toNYC' Congestion – This is the total number of real-time shortage intervals that coincided with congestion on transmission paths into New York City.

Table A-13: Real-Time Reserve Shortages in New York City
2024

	RT Reserve Shortages in NYC in 2024		
Month	**# Intervals**	**Avg. Shortage MW**	**#Intervals w/ toNYC Congestion**
Jan	26	25	10
Feb	19	11	0
Mar	11	17	2
Apr	14	40	0
May	92	99	89
Jun	139	201	0
Jul	442	195	0
Aug	60	69	0
Sep	13	59	0
Oct	4	39	0
Nov	13	46	0
Dec	585	78	0
Total	**1418**	**124**	**101**

Figure A-85 illustrates a sample real-time shortage event on July 10, 2024 when New York City was short of reserves (either 10-minute or 30-minute or both) primarily in the afternoon hours. For each interval from the beginning of hour 9 to the end of hour 21, the figure shows:

- The amount of reserve shortages (red bar); and
- Net imports from upstate areas (blue bar).[297]

When net imports to New York City drop significantly because New York City generators increase output, it creates a reserve import capability that can be used during a contingency. Therefore, when reserve import capability is available into the city, less reserve capacity needs to be held on generators in New York City to maintain reliability.

297 This is calculated as (NYC load) minus (NYC gen) minus (HTP imports) minus (VFT imports) minus (flows on the 901/903 lines into NYC) minus (flows on the A line into NYC).

Figure A-85: Real-Time Reserve Shortages in New York City
Sample Event on July 10, 2024

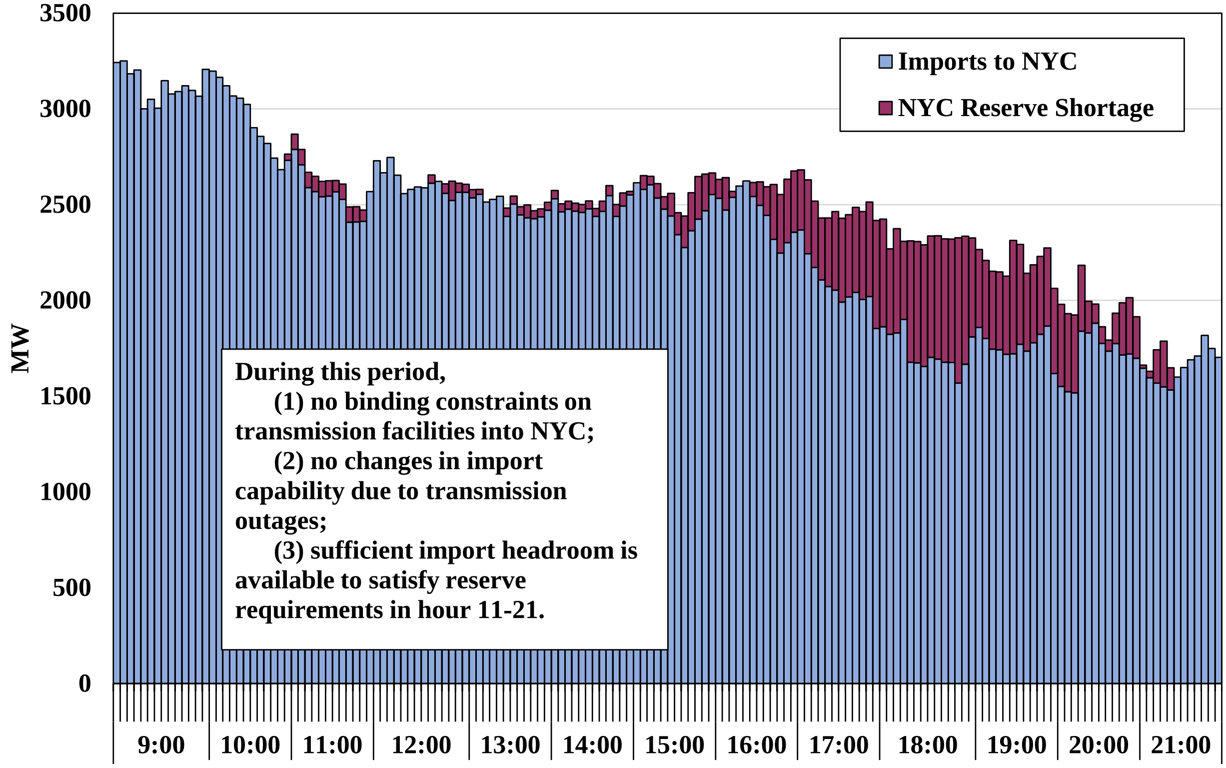


Figure A-86: Comparison of Shortage Pricing in NYISO and Neighboring Markets

In recent years, shortage pricing values in the neighboring PJM and ISO-NE regions have increased dramatically relative to NYISO. While ISO-NE has reserve shortage pricing incentives of $1,000/MWh during a 30-minute reserve shortage, ISO-NE implemented Pay-for-Performance in its capacity market in 2018, which currently provides an additional real-time performance incentive of $5,455/MWh. The additional incentive will rise to $9,337/MWh in June 2025. PJM Capacity Performance rules provide real-time performance incentives of approximately $3,400/MWh, in addition to reserve shortage prices that reach $1,275/MWh during a 10-minute reserve shortage.

These stronger incentives should encourage generators to invest in making their units more reliable and available during tight operating conditions. However, when there is an imbalance between the market incentives provided in two adjacent regions, it can lead market participants to schedule interchange from the area with weaker incentives to the area with stronger incentives even when the area with weaker incentives is in a less-reliable state. In some cases, this could lead the operators of the control area with weaker incentives to maintain reliability through out-of-market actions (e.g., purchases of emergency energy). This may be necessary to maintain reliability in the short-term, but it tends to undermine incentives for investment in the long-term.

Figure A-86 compares incentives for NYISO resources during real-time shortage events to those in neighboring markets. These include maximum 30-minute and 10-minute Non-Spin operating reserve demand curve values as well as Pay-for-Performance penalty rates. A resource may face a total incentive that is the sum of each of these sources when multiple reserve product shortages and/or pay-for-performance scarcity conditions are in effect simultaneously. Values shown for NYISO reflect the revised operating reserve demand curves approved by FERC in 2021, which increased some shadow prices. NYISO 'locational' prices are shown for the regions at the border of each neighboring ISO to indicate the comparative incentives faced by NYISO suppliers when shortage pricing in the neighboring area is in effect.[298]

Figure A-86: Shortage Pricing in NYISO vs. Neighboring Markets

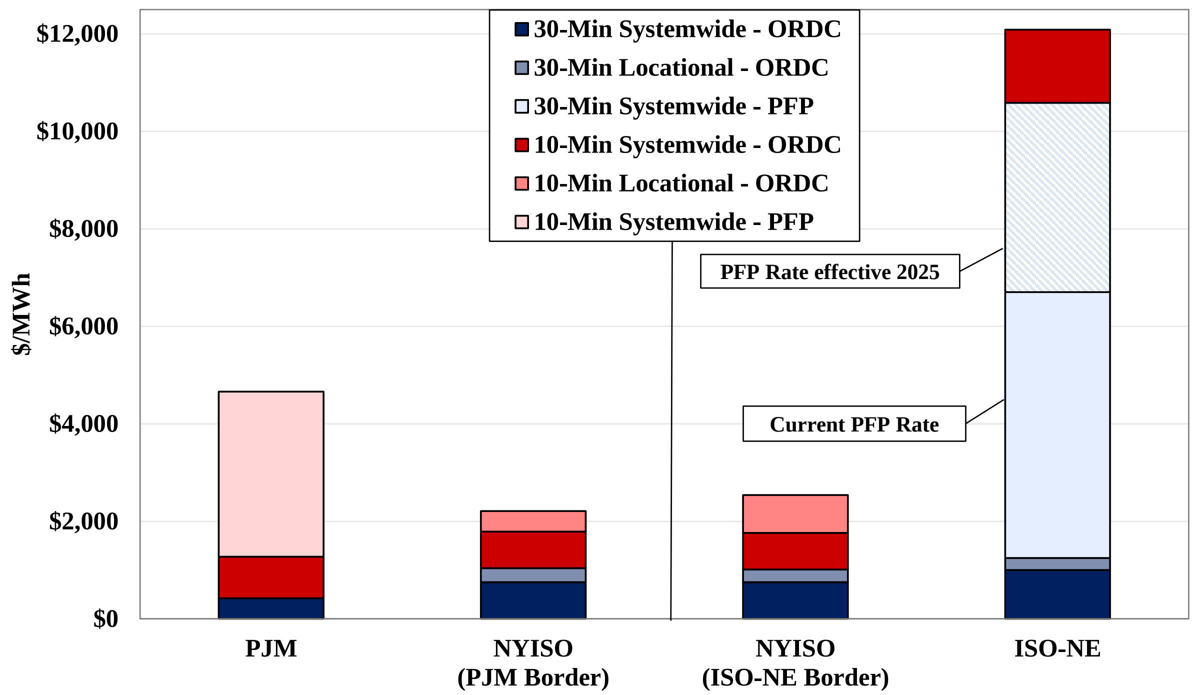


Figure A-87 - Figure A-89: NYISO Operating Reserves Demand Curve vs. MMU EVOLL Curve

The Value of Lost Load ("VOLL") is a well-recognized metric that quantifies the economic impact on consumers during electricity service interruptions. Essentially, VOLL captures the economic value of reliable service and is commonly determined by assessing outage costs. Outage costs are most accurately estimated through survey-based studies, as they leverage real customer experiences to generate more accurate data on outage costs. Survey methodologies underpin the major benchmark studies of outage costs within US jurisdictions including key meta studies that have established versatile outage cost estimators. The most widely referenced meta studies were conducted by Sullivan, et al. from the Berkeley National Laboratory. The initial study was conducted in 2009 ("2009 Berkeley Study") and was subsequently updated in

298 Locational prices for ISO-NE refer to Connecticut. Locational prices for NYISO (PJM Border) assign 54 percent weight to East 30-minute, SENY 30-minute, and East 10-minute shadow prices. Locational prices for NYISO (ISO-NE Border) include the full value of East 30-minute and East 10-minute shadow prices and a 45 percent weight to the SENY 30-minute shadow price. PJM ORDC prices reflect a $1,275/MWh price cap for 10-minute non-spinning reserve shortages, divided between $850 (10 minute) and $425 (30 minute) prices. A shortage of only 30-minute or 10-minute reserves would result in a price of $850/MWh.

2015 ("2015 Berkeley Study"). These studies utilize an econometric model to evaluate the impact of various parameters on outage costs across different customer categories. The coefficients derived from this model can then be utilized to estimate outage costs tailored to specific regions, timeframes, and customer segments. Drawing from these research findings, a VOLL estimate of $30,000 per MWh is considered appropriate for evaluating outage costs within the NYISO market.

The Operating Reserve Demand Curve ("ORDC") represents the marginal reliability value of maintaining certain amount of reserves to avoid shedding load. The marginal reliability value of reserves at any reserve shortage level can be estimated as the Expected Value of Lost Load ("EVOLL") = VOLL × conditional probability of losing load at that shortage level. The slope of the ORDC is influenced by the rate at which the probability of losing load increases as operating reserves decreases, which is estimated from the likelihoods of random contingencies and conditions that could arise during a shortage in the NYISO market.

To account for these unpredictable factors, we employed a Monte Carlo simulation to estimate the conditional probability of losing load for any given level of reserves. This simulation considered random forced generation outages, wind forecast errors, load forecast errors, and import curtailments by neighboring areas.

Generation Forced Outages and Deratings

We utilize a stochastic Markov Process to model random forced outages and deratings for generation resources, including conventional thermal generators and large hydro generators. This modeling approach excludes small run-of-river hydro units and intermittent renewable resources. For each resource, a stochastic Markov Process is developed, where a state space is defined to represent different levels of deratings and a transition matrix is established to capture the transition rates between these capability states. The Markov Process has the following property:

Let T_{ij} be the time the Markov Process spends in state i before entering into a different state j. The time T_{ij} is exponentially distributed with transition rate a_{ij}, and the transition probability from state i to state j over a time interval Δt is:

$$P_{ij}(\Delta t) = \Pr\left(T_{ij} \leq \Delta \mathrm{t}\right) = 1 - \mathrm{e}^{-a_{ij}\Delta \mathrm{t}}$$

During the Monte Carlo simulation, this probability is compared to a random number between zero and one to simulate forced outages and deratings for each resource. For this analysis, we utilize the transition rate matrices developed for the annual IRM/LCR study conducted for the NYISO capacity market. Additionally, we model all existing resources as being online but their available capability is adjusted using the following formula to reflect average participation during summer peak conditions:

*Modeled Capacity = ICAP * Participation Factor*

For each resource, its Participation Factor is calculated as the ratio of the actual total online capacity to the total ICAP during the afternoon peak hours (from HB15 to HB 20) in July and August. It is important to note that this metric assumes resources are fully contributing to meet energy, ancillary services, headroom, and ramp capability needs. This approach differs from a traditional capacity factor, which measures the energy output as a ratio of generation capability.

Wind Forecast Errors

Intermittent resources are represented in our simulation as forecast uncertainties. For the purpose of this analysis, we only consider land-based wind resources, given the limited capacity currently available from in-service solar, offshore wind, and battery storage resources within the NYISO market. However, as the penetration of these resources grows in the coming years, our methodology can be expanded to include them.

To quantify forecast errors, we computed aggregate forecast discrepancies from select historical periods across various forecast windows (e.g., 15 minutes, 30 minutes, or 60 minutes, etc.). The errors equal the difference between actual wind outputs in time t and the forecasted outputs at different time intervals preceding t (e.g., 15 minutes prior to t). We then modeled these actual error distributions using standardized normal distributions, with mean and standard deviations derived from the observed data.

During the Monte Carlo simulation, a distinct random number between zero and one is generated for each iteration, which serves as the probability distribution for wind forecast errors. The simulated wind forecast error is determined by the corresponding inverse of the normal cumulative distribution. We model both over-forecasts and under-forecasts in our analysis.

Net Load Forecast Errors

Net load (= load – BTM solar) forecast uncertainties are considered in our simulation. Similar to simulating wind forecast uncertainties, we represent net load forecast errors with standardized normal distribution curves, with mean and standard deviations calculated from select historical periods across different forecast windows. The Monte Carlo simulation utilizes random numbers between zero and one and their corresponding inverse of these normal cumulative distributions to model net load forecast uncertainties. Both over-forecasts and under-forecasts of net load are simulated in this analysis.

Import Curtailments from Neighboring Areas

Neighboring control areas often curtail their exports to New York after being scheduled by RTC due to various reasons, such as unforeseen reliability issues, bid mismatches, checkout failures, or transmission delivery bottlenecks. These close-to-real-time curtailments introduce unexpected supply losses to the NYISO market, which our simulation accounts for.

We calculated the aggregate import curtailments across all interfaces between New York and neighboring control areas using data from select historical periods. Our simulation incorporates the observed frequency of curtailments, while the magnitude of these curtailments is estimated using a standardized exponential distribution. The mean of this distribution is derived from the observed data. In the Monte Carlo simulation, random numbers between zero and one are generated for each iteration. These numbers are then used with the inverse of the exponential cumulative distribution to model the quantity of import curtailments.

These four random factors described above are then summed together to calculate the net supply loss in each iteration of the Monte Carlo simulation:

Net Supply Loss = Forced-Out Generation Capacity + Wind Over-forecast + Net Load Under-forecast + Import Curtailment

The conditional probability of lost load at any point (x MW) on the ORDC curve is then calculated as:

$$\Pr\{Load\ Shed|\ x\ MW\ of\ reserves\ available\} = \frac{The\ number\ of\ iterations\ yielding\ net\ supply\ loss > x\ MW}{The\ total\ number\ of\ iterations}$$

The EVOLL at x MW on the ORDC curve equals:

$$EVOLL = VOLL * \Pr\{Load\ Shed|\ x\ MW\ of\ reserves\ available\}$$

Figure A-87 shows our estimated EVOLL curves for NYCA-wide operating reserves for an outage recovery period of 15 minutes, 30 minutes, one hour, and two hours, respectively. These EVOLL curves are compared to existing ORDCs in the NYISO market.

We compare the EVOLL curves with the stacked ORDCs because they represent the cumulative value of reserves available for deployment within each respective outage recovery period. For example, only 10-minute reserves can be deployed within the 15-minute outage recovery period, while both 10-minute and 30-minute reserves can be deployed within the 30-minute outage recovery period. Consequently, the 15-minute EVOLL curve indicates the economic value of 10-minute reserves, compared to the combined 10-Spin ORDC and 10-Minute ORDC. This comparison is shown separately in Figure A-88. The analysis reveals that approximately half of the current ORDC curve significantly undervalues the marginal reliability of 10-minute reserves. Moreover, the MMU EVOLL curve extends beyond the existing 1310 MW of 10-minute reserve requirements. This extended portion could serve as the pricing basis for additional reserves in the form of 10-minute reserves that are procured to address uncertainties associated with intermittent resource availability.[299]

Likewise, the 30-minute EVOLL curve represents the economic value of both 10-minute and 30-minute reserves, compared to the combined 10-Spin ORDC, 10-Minute ORDC, 30-Minute ORDC. We derive an EVOLL-based 30-minute ORDC as the difference between the 30-minute EVOLL and the 15-minute EVOLL. Figure A-89 shows this MMU economic 30-minute ORDC, compared to the current 30-minute ORDC.

299 See *Balancing Intermittency: Percentiles and Shortage Pricing Curves*, ICAPWG/MIWG, March 4, 2024.

Figure A-87: NYISO ORDCs vs. MMU EVOLL Curves for up to 2 Hour Reserves

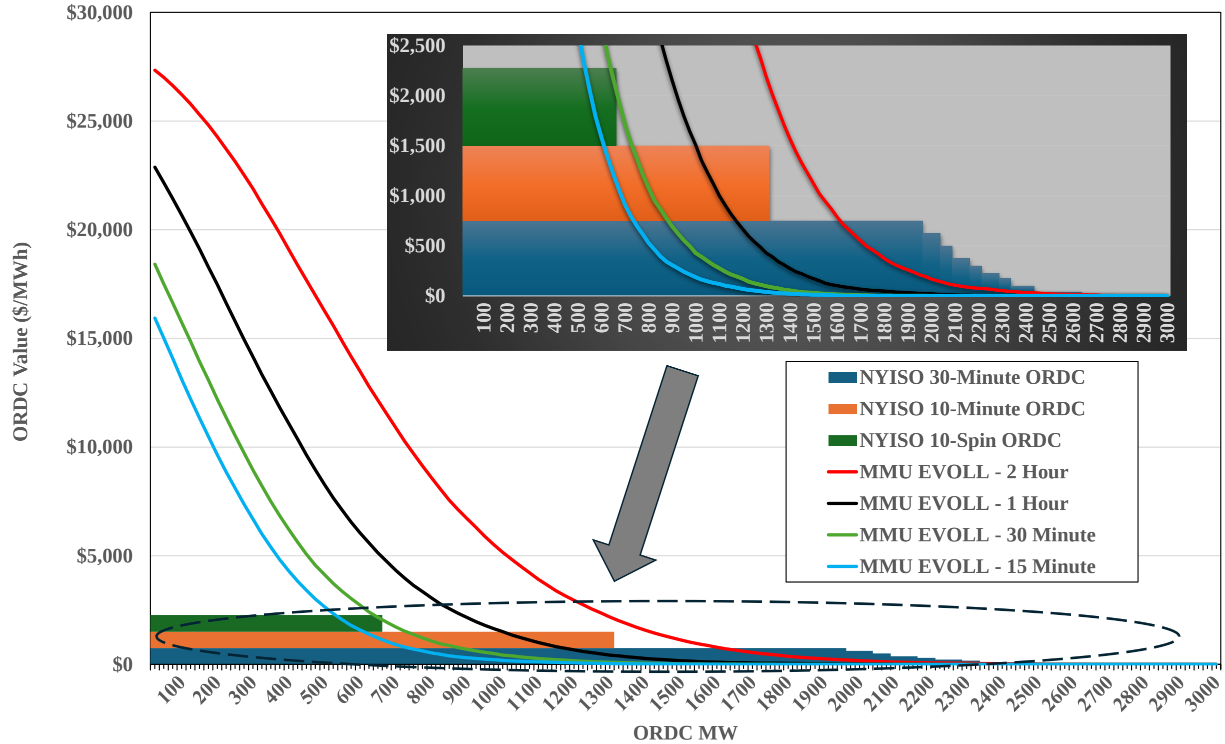


Figure A-88: NYISO ORDC vs. MMU EVOLL Curve for 10-Minute Reserves

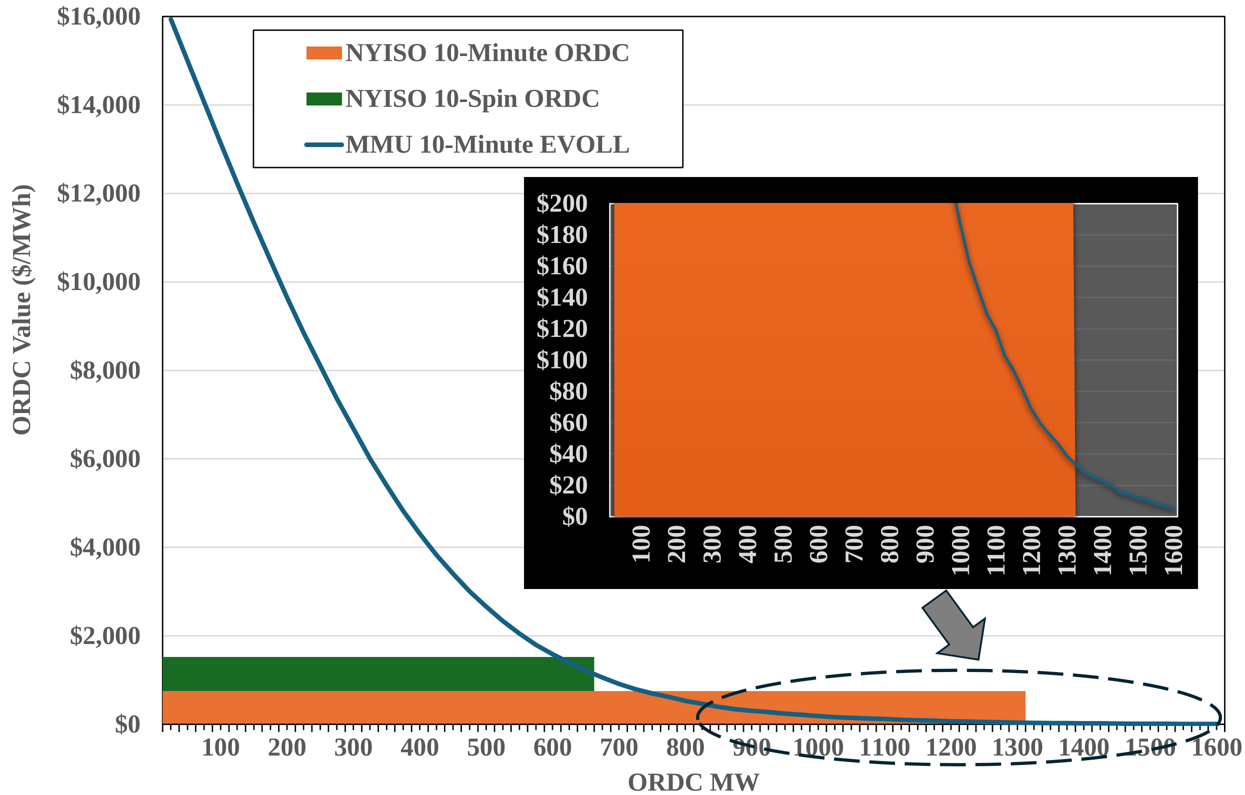
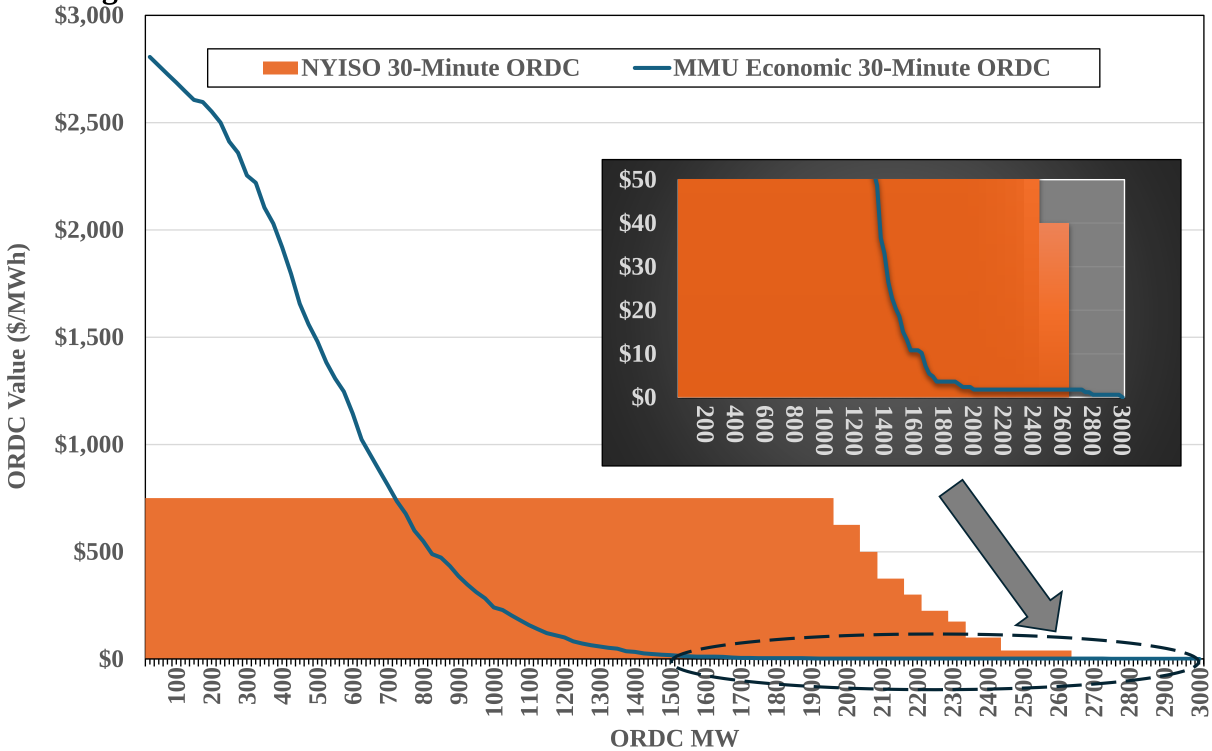


Figure A-89: NYISO ORDC vs. MMU EVOLL Curve for 30-Minute Reserves



I. Offline GT Pricing and Transmission Shortages

Transmission shortages occur when power flows exceed the limit of a transmission constraint. While such transmission shortages may require the ISO to shed firm load to maintain system security, they often persist for many hours without necessitating load shedding or causing equipment damage. During transmission shortages, it is important for wholesale markets to set efficient prices that accurately reflect the acuteness of operating conditions. Efficient pricing provides incentives for generation and demand response resources to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, including online units that ramp in five minutes and offline quick-start gas turbines that start and synchronize within 10 minutes. If the available physical capacity is insufficient to resolve a transmission constraint, a Graduated Transmission Demand Curve ("GTDC") is used to set prices under shortage conditions. NYISO first implemented the GTDC approach on February 12, 2016,[300] and made two subsequent enhancements to improve market efficiency during transmission shortages.[301,302]

Additionally, a condition similar to a shortage occurs when an offline quick-start gas turbine is counted towards resolving a transmission constraint but is not given a startup instruction.[303] In such cases, the marginal cost of resources actually dispatched to relieve the constraint is lower than the shadow price set by the offline gas turbine (which is not actually started). The Commission has recognized that it is not efficient for such units to set the clearing price because they: (a) do not reflect the marginal cost of supply that is available to relieve the constraint in that time interval, and (b) do not reflect the marginal value of the constraint that may be violated when it does not generate as assumed in RTD.[304] This category of shortage is evaluated in this section.

Figure A-90: RT Congestion Management with GTDCs

Offline GTs have been used far more frequently to manage congestion on Long Island's transmission facilities compared to other regions in recent years. Accordingly, Figure A-90 focuses on analyzing the price effects of offline GTs on transmission constraints specific to Long Island, grouped based on CRMs used: (a) the 345 kV transmission circuits from upstate to Long Island with a CRM of 50 MW; (b) the 138 kV transmission constraints on Long Island with a CRM of 20 MW; and (c) the 69 kV transmission constraints on Long Island with a CRM of 10 MW.

The scatter plots show transmission constraint shadow prices on the y-axis and transmission violations on the x-axis. For a given constraint shadow price, the blue diamond represents the transmission violation as recognized by RTD, while the red diamond represents the violation after excluding the relief provided by offline GTs.

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300 See Section V.F in the Appendix of our *2016 State of Market Report* for a detailed description of the initial implementation of the GTDC.

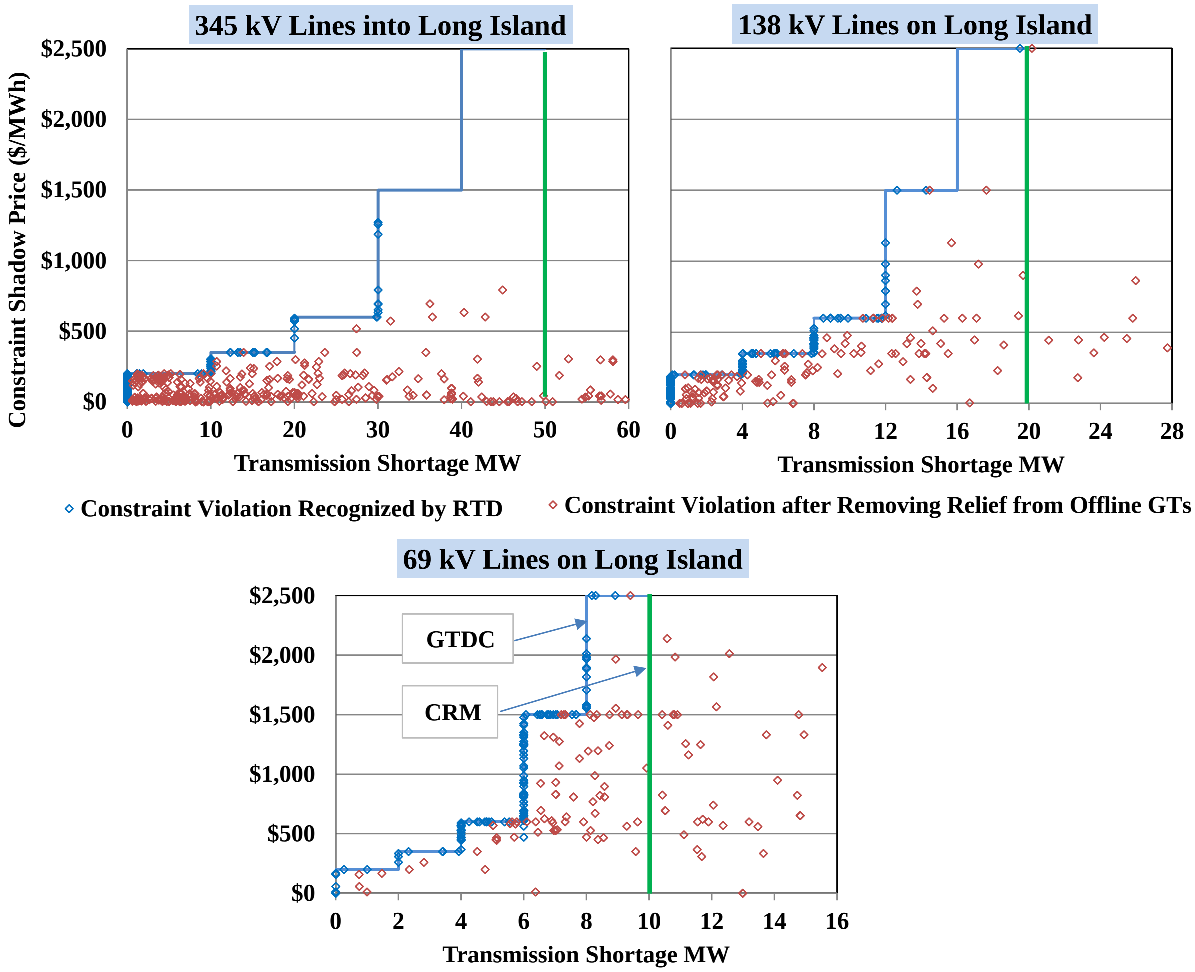
301 The first enhancement was made on June 20, 2017. Key changes include: 1) modifying the second step of the GTDC from $2350 to $1175/MWh; and 2) removing the "feasibility screen" and applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM"). A CRM is a reduction in actual physical limit used in the market software, largely to account for loop flows and other un-modeled factors. These changes are discussed in detail in Commission Docket ER17-1453-000.

302 The second enhancement was made on November 14, 2023. Key changes include: 1) replacing the three-step GTDC curve with a six-step curve with distinct shortage values at $200, $350, $600, $1500, $2500, and $4000, respectively; and 2) replacing the static 20 MW GTDC curve with a CRM-dependent curve for each transmission facility. Each of the first five steps of the GTDC curve equals to 20 percent of the assigned CRM value. These changes are discussed in detail in Commission Docket ER23-1863-000.

303 Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD but does not satisfy the start-up requirement (i.e., economic for at least three intervals and scheduled at the full output level for all five intervals), it will not be instructed to start-up after RTD completes execution.

304 In Docket RM17-3-000, see the Commission's NOPR on Fast Start Pricing, dated December 15, 2016, and comments of Potomac Economics, dated March 1, 2017.

Figure A-90: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2024



J. Supplemental Commitment for Reliability

When the wholesale market does not meet all forecasted load and reliability requirements, the NYISO (or an individual Transmission Owner) commits additional resources to ensure that sufficient resources will be available in real-time. Supplemental commitments increase the amount of supply available in real-time, leading to distorted real-time market prices, which tend to undermine market incentives for meeting reliability requirements and generate expenses that are uplifted to the market. Hence, it is important for supplemental commitments to be as limited as possible.

In this subsection, we examine supplemental commitment for reliability and focus particularly on New York City where most reliability commitments occur. In the next subsection, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

Figure A-91: Supplemental Commitment for Reliability in New York

Supplemental commitment occurs when a generator is not committed by the economic pass of the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in the following three ways:

- Day-Ahead Reliability Units ("DARU") Commitment, which typically occurs at the request of local Transmission Owner prior to the economic commitment in SCUC;
- Day-Ahead Local Reliability ("LRR") Commitment, which takes place during the economic commitment pass in SCUC to secure reliability in New York City; and
- Supplemental Resource Evaluation ("SRE") Commitment, which occurs after the day-ahead market closes.

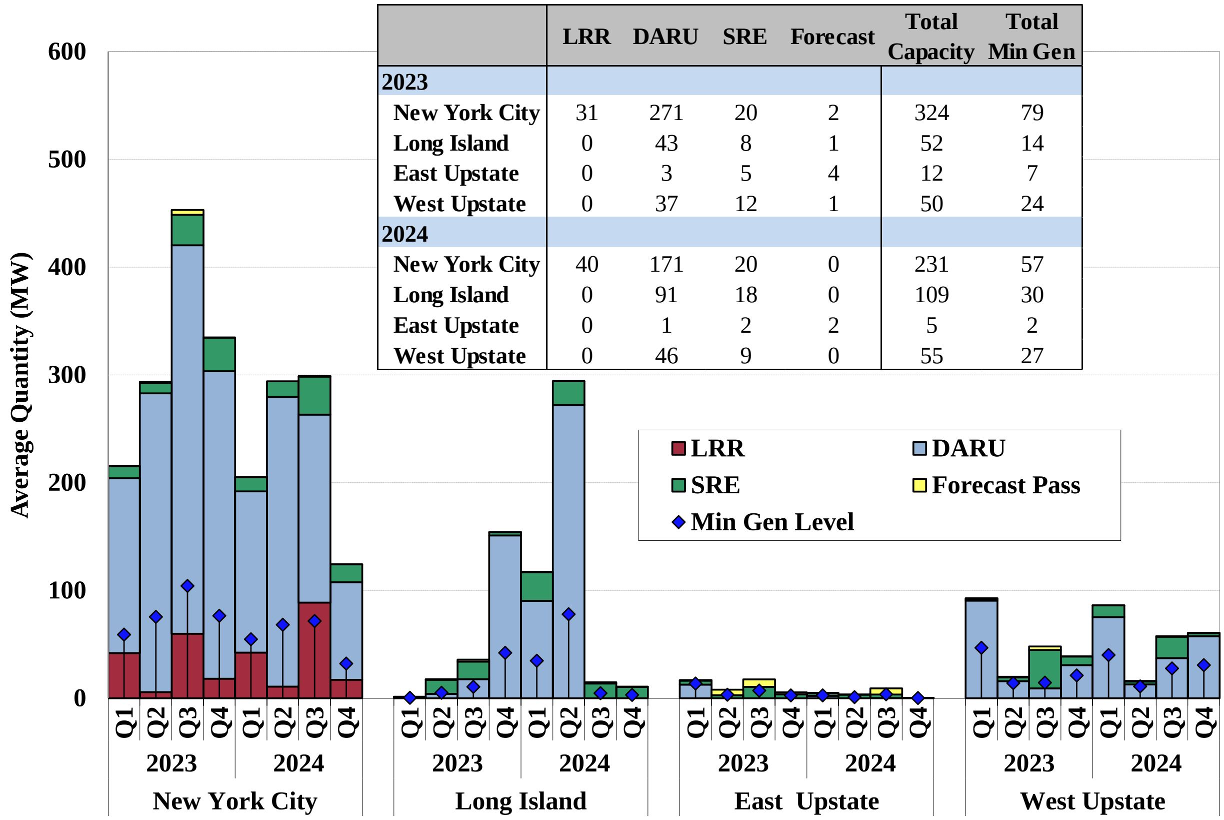
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift caused by these commitments results from guarantee payments to economically committed generators that do not cover their as-bid costs at the reduced LBMPs. Hence, it is important to commit these units as efficiently as possible.

To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected outside the economic evaluation of SCUC. However, to commit units efficiently, SCUC must have accurate assumptions regarding the needs in each local reliability area.

Figure A-91 shows the quarterly quantities of total capacity (the stacked bars) and minimum generation (the markers) committed for reliability by type of commitment and region in 2023 and 2024. Four types of commitments are shown in the figure: DARU, LRR, SRE, and Forecast Pass. The first three are primarily for local reliability needs. The Forecast Pass represents the additional commitment in the forecast pass of SCUC after the economic pass, which ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load.

The figure shows these supplemental commitments separately for the following four regions: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The table in the figure summarizes these values for 2023 and 2024 on an annual basis.

Figure A-91: Supplemental Commitment for Reliability in New York
By Category and Region, 2023 – 2024



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2023						
New York City	31	271	20	2	324	79
Long Island	0	43	8	1	52	14
East Upstate	0	3	5	4	12	7
West Upstate	0	37	12	1	50	24
2024						
New York City	40	171	20	0	231	57
Long Island	0	91	18	0	109	30
East Upstate	0	1	2	2	5	2
West Upstate	0	46	9	0	55	27

Figure A-92 & Figure A-93: Forecast-Pass Commitment in New York

In the day-ahead market, when the Bid Load Pass does not commit enough physical resources to meet forecast load and reserves requirements, the subsequent Forecast Pass will commit additional physical resources accordingly (indicated by the yellow bars in Figure A-91). However, this need is not currently priced in the market software, leading units committed for this purpose to often recoup their costs through BPCG uplift. Although the amount of FCT-committed capacity was modest on the vast majority of days, it would still be beneficial to reflect the underlying needs through market signals.

Figure A-92 examines Forecast Pass commitments. The x-axis shows all days when Forecast Pass commitments occurred in 2024. The solid blue bar shows, for each day, the total MWh committed by the Forecast Pass, including capacity from slow-start units and non-blocked quick-start units. The empty bar shows available offline capacity from non-blocked quick-start units during the hours when FCT commitments occurred. This capacity is currently not treated the same as blocked quick-start units in the FCT pass to satisfy load and reserve requirements. If these units were recognized as quick-start by the software, most of the FCT commitments would not have been needed.

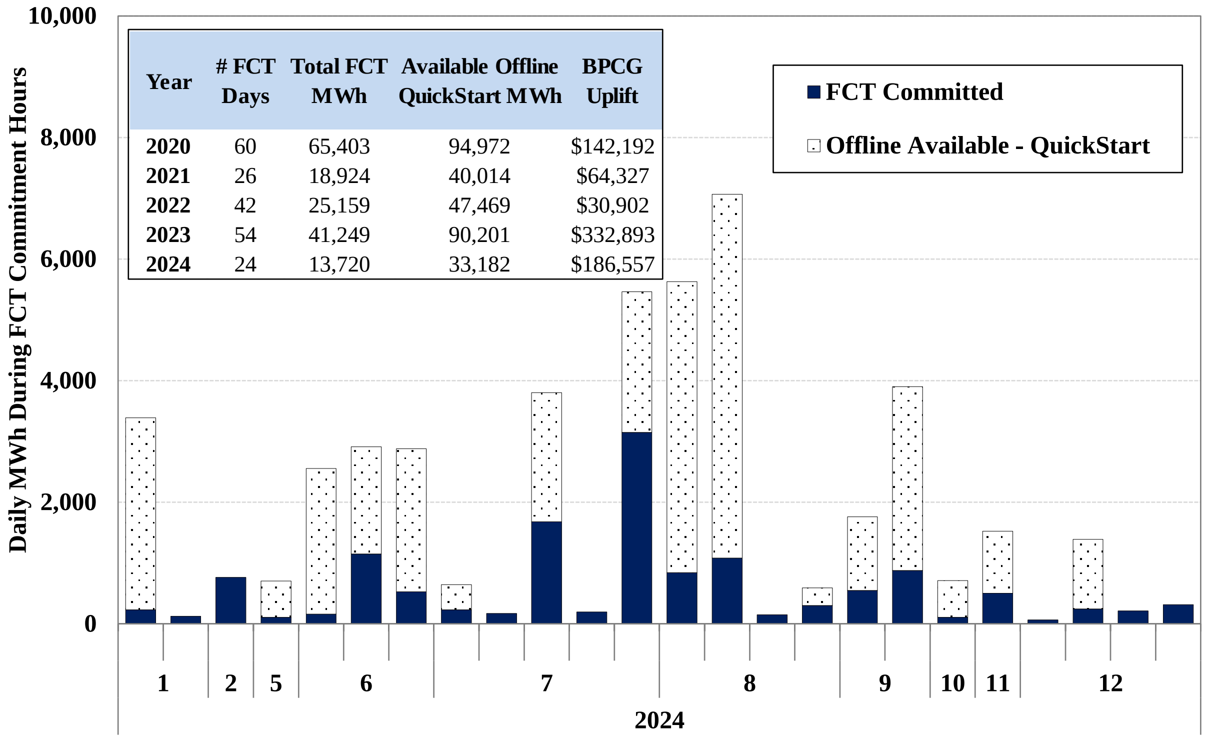
The inset table summarizes annual totals from 2020 to 2024 for: (i) number of days when FCT commitments occurred; (ii) MWh committed in the FCT pass; (iii) available offline capacity from non-blocked quick-start units during FCT commitment hours; and (iv) resulting BPCG uplift.

Figure A-93 compares the FCT commitment with forecast physical energy needs in the day-ahead market in 2024, summarizing the following quantities on a daily basis:

- *Forecast Required Energy for Dispatch* – This summarizes the difference between NYISO forecasted load and scheduled physical energy in the economic pass, in total MWh for each day; and
- *Forecast-Pass Committed Capacity* – Summarizes additional capacity committed in the forecast pass to meet NYISO forecast load on each day. The reported quantity includes capacity from internal slow-start resources and non-blocked quick-start units in the hours where it is not online in the economic pass but is online in the forecast pass.

Figure A-92: Forecast-Pass Commitment

2024



Year	# FCT Days	Total FCT MWh	Available Offline QuickStart MWh	BPCG Uplift
2020	60	65,403	94,972	$142,192
2021	26	18,924	40,014	$64,327
2022	42	25,159	47,469	$30,902
2023	54	41,249	90,201	$332,893
2024	24	13,720	33,182	$186,557

Figure A-93: FCT Commitment and DAM Forecast Physical Energy Needs
By Day, 2024

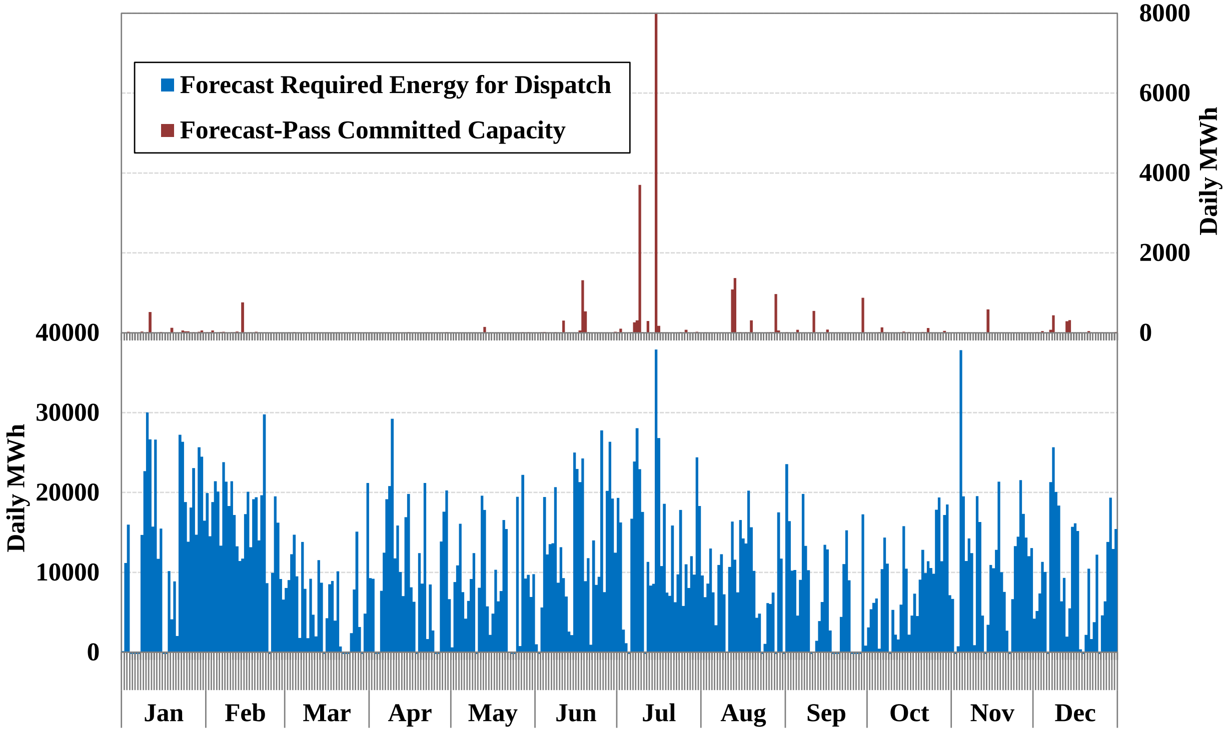


Figure A-94: Key drivers to SRE Commitments for Systemwide Capacity

The following chart highlights three main categories of supply and demand changes after the day-ahead market that contributed to a shortfall in capacity margin and necessitated SRE commitments by NYISO.

- **Reduction in Expected Imports**: This category represents expected reductions of in scheduled net imports, primarily from virtual external transactions. Additional reduction comes from physical transactions that fail to clear the day-ahead checkout process or are expected to reduce because of real-time system conditions.
- **Increases in Load Forecast**: This category shows the reduction in supply margin due to upward adjustments in load forecasts.
- **Generator Derates and Outages:** This category represents the reduction in generating capacity caused by resource outages and deratings.

When the total loss in supply exceeds day-ahead scheduled supply margin, NYISO initiates an SRE commitment to secure additional resources. These SREs reflect reserve needs that are not fully represented in the day-ahead market.

Figure A-94: Key Drivers to SRE Commitments for Systemwide Capacity
2023 - 2024

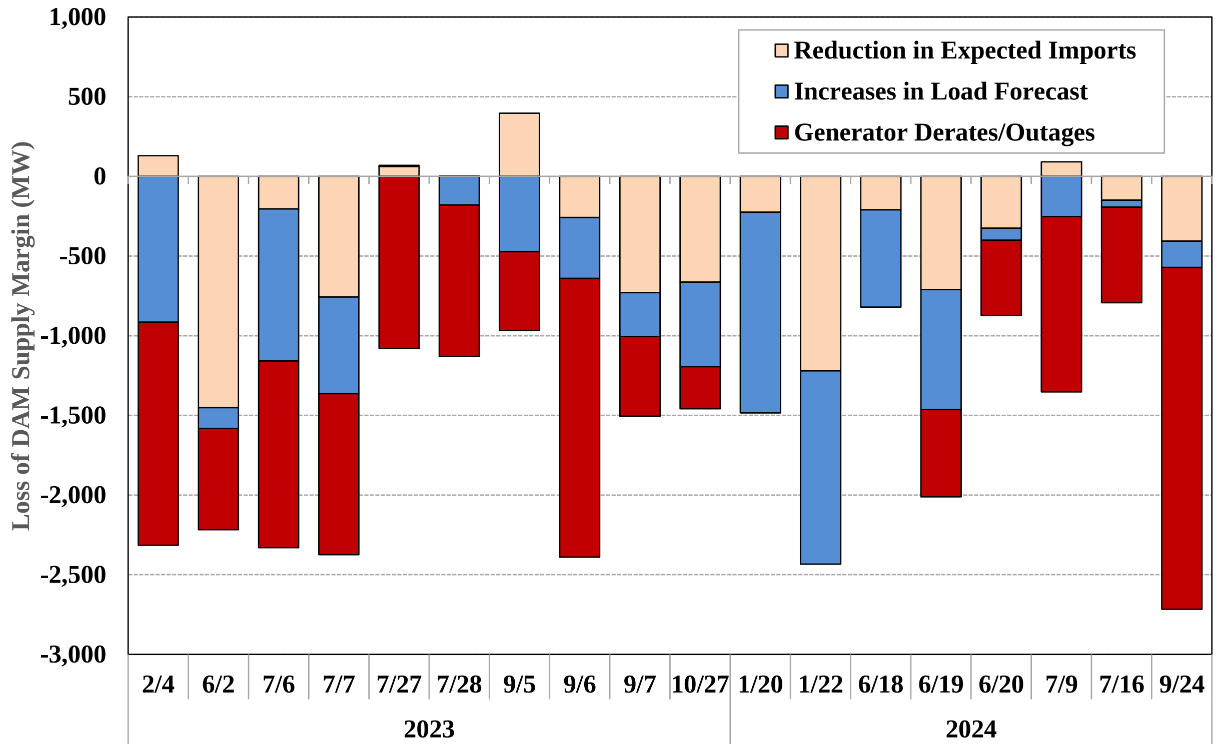


Figure A-95 & Figure A-96 : Supplemental Commitment for Reliability in New York City and North Country Load Pockets

Figure A-95 examines the necessity of reliability commitments in New York City, which accounted for the majority of the reliability commitments in NYCA during 2024. The figure shows the reliability commitment quantities in stacked bars for each month of 2024 in four distinct categories:

- **Economic MWh:** This category represents the total MWh of the initial DARU commitments that eventually qualify as economic capacity within the scheduling software (because they are still committed if the DARU and LRR requirements are removed from the SCUC run).
- **Verified – Needed MWh:** This category represents the total MWh of the initial DARU commitments and applicable LRR and SRE commitments that do not qualify as **Economic** but are verified by the MMU's assessment as necessary for maintaining reliability (including known thermal and voltage requirements) in the applicable load pockets.
  - Our assessment relies on information available in the day-ahead and real-time markets, including factors such as load forecast, resource availability, and transmission network conditions.
- **Verified – Headroom MWh:** This category represents the total MWh that are associated with **Verified** commitments but exceed the amount of **Needed** MWh.

  - For example, if a 100 MW unit is verified for a reliability need of 50 MWh over two hours but has a minimum run time commitment of five hours, the headroom MWh would be 450 MWh (= 5*100-50).

- **Unverified MWh:** This category represents the remaining DARU and SRE commitments that do not fit into the other three categories.

Figure A-95: Evaluation of DARU/LRR/SRE Commitments in New York City
By Month, 2024

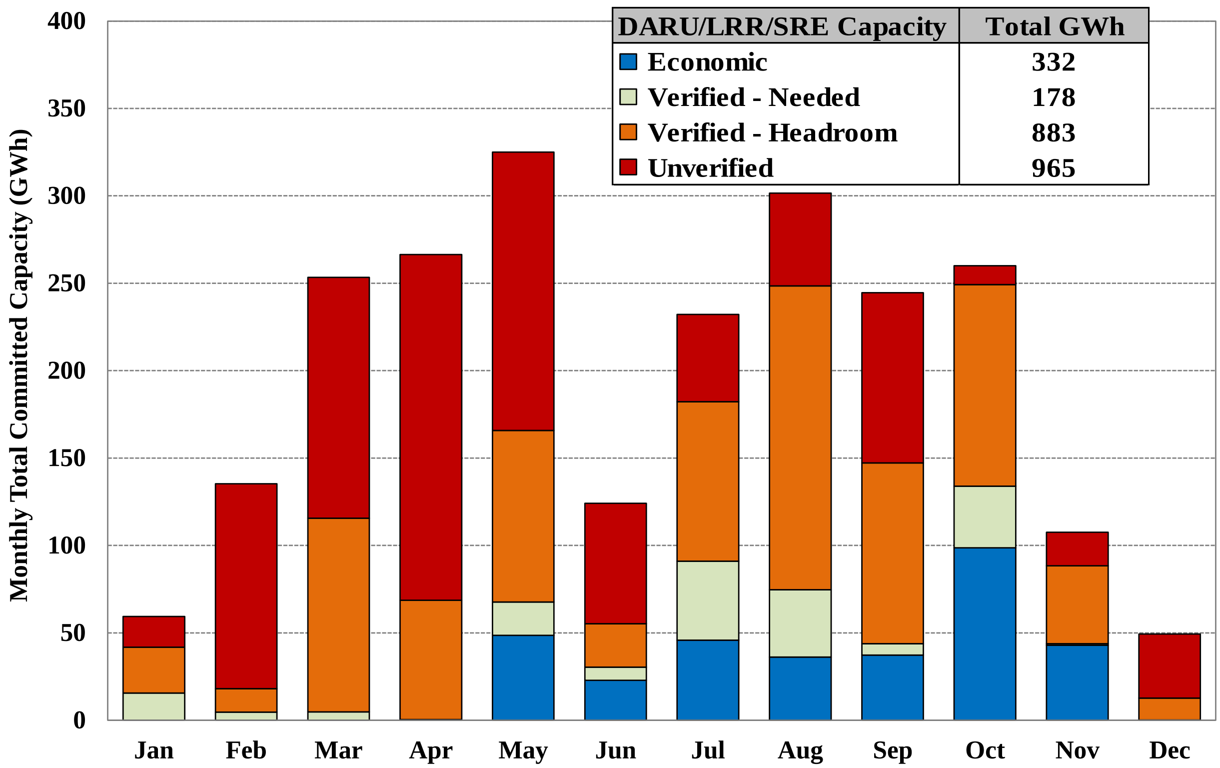
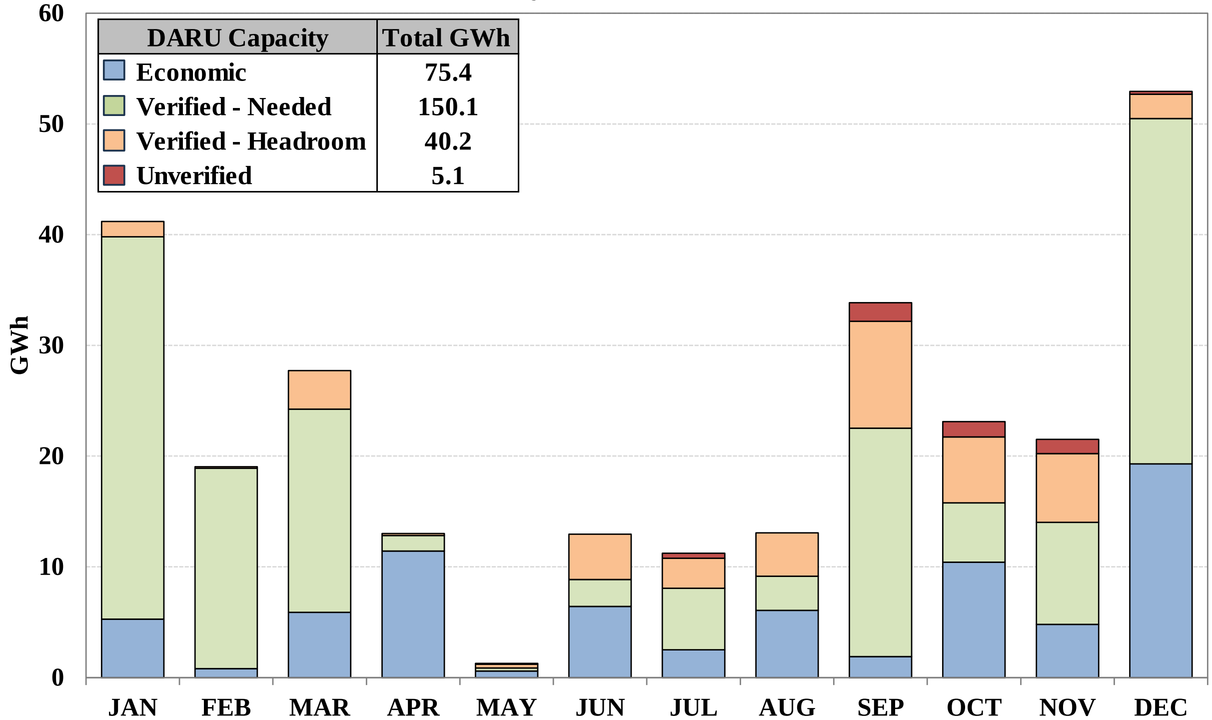


Figure A-96 examines the necessity of day-ahead reliability commitments of fossil fuel generators in the North Zone for North Country Reliability across 2024. The figure shows the reliability commitment quantities in the same four categories as used in the N.Y.C. analysis of Figure A-95. Reliability commitments in the region have been abnormally high in recent years due to ongoing maintenance work related to the various Smart Path transmission upgrades.

Figure A-96: Evaluation of DARU Commitment for North Country Reliability
By Month, 2024



K. Uplift Costs from Guarantee Payments

Uplift charges from guarantee payments accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. The following figures summarize the three categories of non-local reliability uplift that are allocated to all Load Serving Entities ("LSEs") and the four categories of local reliability that are allocated to local Transmission Owners.

The three categories of non-local reliability uplift are:

- Day-Ahead Market – This primarily includes guarantee payments to generators that are economically committed in the day-ahead market. These generators receive payments when day-ahead clearing prices are not high enough to cover the total of their as-bid costs (includes start-up, minimum generation, and incremental costs). When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.
- Real-Time Market – Guarantee payments are made primarily to gas turbines that are committed by RTC and RTD based on economic criteria, but do not receive sufficient revenue to cover start-up and other running costs over their run time. Guarantee payments in the category are also made for: a) SRE commitments and out-of-merit dispatch that are done for bulk power system reliability; b) imports that are scheduled with an offer price greater than the real-time LBMP; and c) demand response resources (i.e., EDRP/SCRs) that are deployed for system reliability.

- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules. When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

The four categories of local reliability uplift are:

- Day-Ahead Market – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule (“LRR”) or as Day-Ahead Reliability Units (“DARU”) for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.
- Real-Time Market – Guarantee payments are made to generators committed and redispatched for local reliability reasons after the day-ahead market. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation (“SRE”) commitments.
- Minimum Oil Burn Compensation Program – Guarantee payments made to generators that cover the spread between oil and gas prices when generators burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

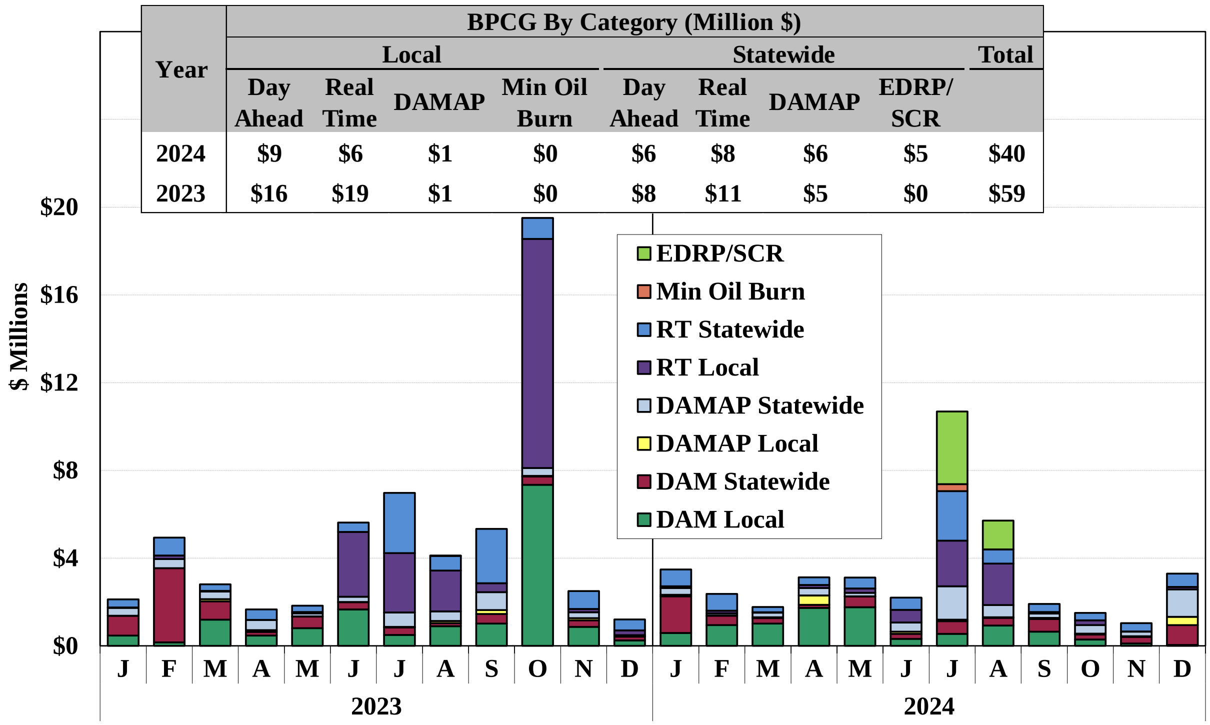
Figure A-97 - Figure A-98: Uplift Costs from Guarantee Payments

Figure A-97 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2023 and 2024. The uplift costs associated with the EDRP/SCR resources are shown separately from other real-time statewide uplift costs. The table summarizes the total uplift costs under each category on an annual basis for these two years.

Figure A-98 shows the seven categories of uplift charges on a quarterly basis in 2023 and 2024 for four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The uplift costs paid to import transactions from neighboring control areas and EDRP/SCR resources are shown separately from the generation resources in these four regions in the chart. The table summarizes the total uplift costs in each region on an annual basis for these two years.

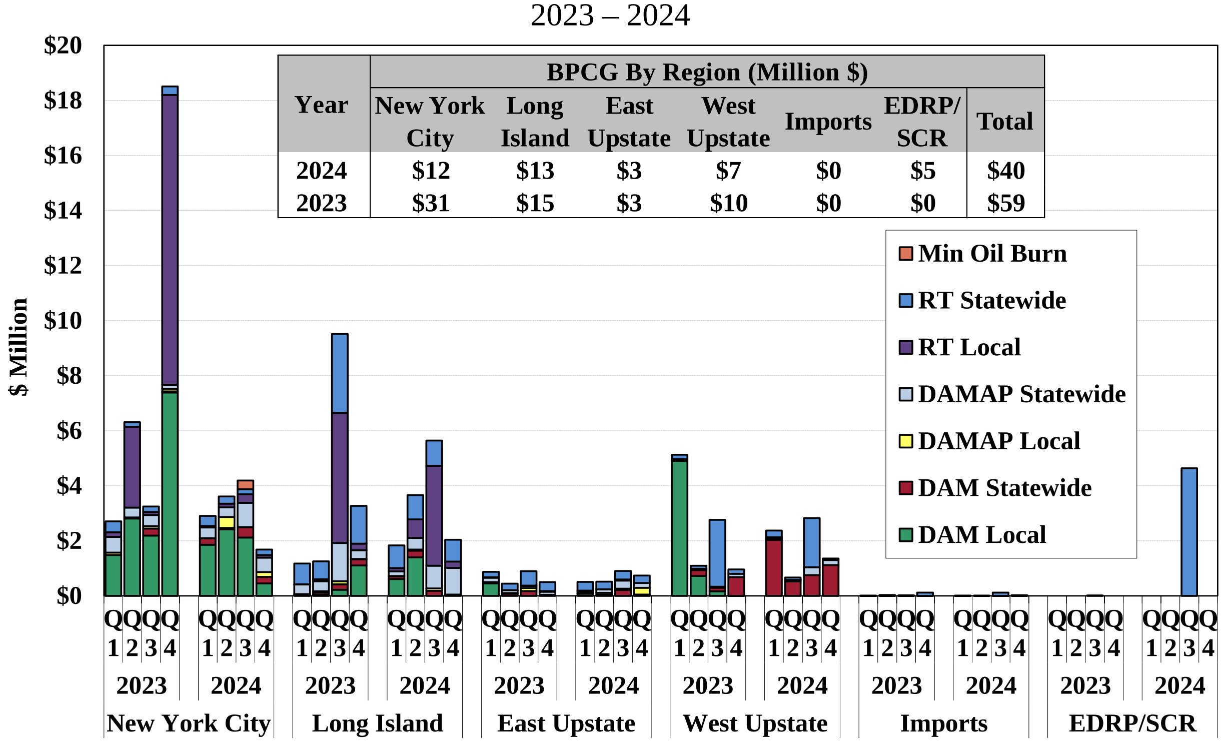
It is also noted that these two figures are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-97: Uplift Costs from Guarantee Payments by Month
2023 – 2024



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2024	$9	$6	$1	$0	$6	$8	$6	$5	$40
2023	$16	$19	$1	$0	$8	$11	$5	$0	$59

Figure A-98: Uplift Costs from Guarantee Payments by Region
2023 – 2024



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2024	$12	$13	$3	$7	$0	$5	$40
2023	$31	$15	$3	$10	$0	$0	$59

VI. CAPACITY MARKET

This section evaluates the performance of the capacity market, which is designed to ensure that sufficient resources are available to satisfy New York's planning reserve margin requirements. The capacity market supplements the incentives provided by the energy and ancillary services markets. In combination, these three sources of revenue provide incentives for new investment, retirement decisions, and participation by demand response.

The New York State Reliability Council ("NYSRC") determines the Installed Reserve Margin ("IRM") for NYCA, which is the amount of planning reserves necessary to meet the reliability standards for New York State. NYISO uses the IRM in conjunction with the annual peak load forecast to calculate the Installed Capacity ("ICAP") requirement for NYCA.[305] NYISO also determines the Minimum Locational Installed Capacity Requirements ("LCRs") for New York City, the G-J Locality, and Long Island, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirement.[306]

Since NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates known as Derating Factors. The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual coincident peak load in each area. LSEs can satisfy their UCAP requirements by purchasing capacity through bilateral contracts, by self-scheduling their own capacity, or by participating in UCAP market auctions run by NYISO.

NYISO conducts three UCAP auctions: a forward strip auction where UCAP is transacted in six-month blocks for the upcoming capability period, a monthly forward auction where UCAP is transacted for the remaining months of the capability period, and a monthly spot auction. The two forward markets are voluntary, but all requirements must be satisfied at the conclusion of the spot market immediately prior to each month. Market participants that have purchased more than their obligation prior to the spot auction sell the excess into the spot auction. Demand curves are used to determine the clearing prices and quantities purchased in each locality in each monthly UCAP spot auction.[307] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction purchases more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

The demand curve for a Locality is defined as a straight line through the following two points:

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305 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 22 percent in the most recent Capability Year (i.e., the period from May 2024 to April 2025). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

306 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. These are set in the annual Locational Minimum Installed Capacity Requirements Study, which may be found here.

307 The capacity demand curves are not used in the forward strip auction and the forward monthly auction. The clearing prices in these two forward auctions are determined based on participants' offers and bids.

- Net CONE at Level of Excess – The demand curve price equals the levelized cost of a new peaking unit (net of estimated energy and ancillary services revenue) when the quantity of UCAP procured exceeds the UCAP requirement by a small margin known as the "Level of Excess".[308]
- $0 at Zero Crossing Point – The demand curve price equals $0 when the quantity of UCAP procured exceeds the UCAP requirement by 12 percent for NYCA, 15 percent for the G-J Locality, and 18 percent for both New York City and Long Island.

Every four years, NYISO establishes the capacity demand curves through a study that includes a review of the selection, costs, and revenues of the peaking technology. Each year, NYISO further adjusts the demand curve to account for changes in Net CONE of a new peaking unit.

This report evaluates a period when there were four capacity market Localities: G-J Locality (Zones G to J), New York City (Zone J), Long Island (Zone K), and NYCA (Zones A to K). New York City, Long Island and the G-J Locality are each nested within the NYCA Locality. New York City is additionally nested within the G-J Locality. The clearing price in a nested Locality cannot be lower than the clearing price in the surrounding Locality.

This section evaluates the following aspects of the capacity market:

- Trends in internal installed capacity, capacity exports, and imports from neighboring control areas (sub-sections A and B);
- Equivalent Forced Outage Rates ("EFORds") and Derating Factors (sub-section C);
- Capacity supply and quantities purchased each month as well as clearing prices in monthly spot auctions (sub-section D);
- Analyses of the efficiency of the capacity market design, including the correlation of monthly spot prices with reliability value over the year (sub-section E), zonal spot prices with reliability value in each region (sub-section F), and our proposed approach for adjusting the capacity payments of generators that have a positive or negative impact on transfer capability that affect planning reliability needs (sub-section G);
- Need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section H);
- Our recommendation to address the potential for extreme market conditions before NYISO implements a seasonal capacity market if large resources sell significantly less capacity in the winter than in the summer (sub-section I); and
- Our assessment of key inefficiencies that result from the use of the deliverability construct rather than efficient capacity pricing to limit capacity additions in export-constrained areas (sub-section J).

308 The demand curves have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves can be found on NYISO's webpage, available here.

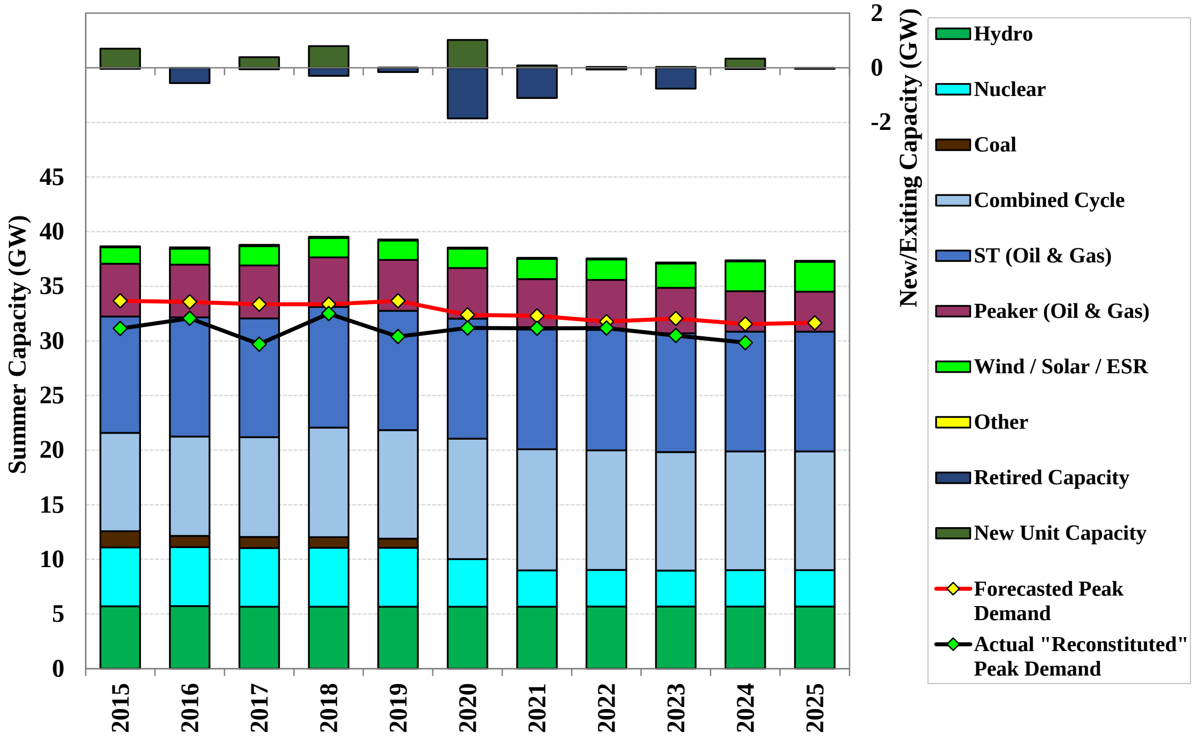
A. Installed Capacity of Generators in NYCA

Figure A-99 - Figure A-100: Installed Summer Capacity and Forecasted Peak Demand

The following figures show the amount of installed capacity in specific regions by fuel and technology type and how they have changed over time. Capacity has shifted away from coal and nuclear toward natural gas and renewable resources. Since the retirement of the Indian Point nuclear units in 2020 and 2021, Eastern New York has become largely dependent on fossil-fueled capacity with virtually all renewable, hydro, and nuclear resources in upstate regions.

The bottom panel of Figure A-99 shows the total installed summer capacity of generation (by prime mover) and the forecasted and actual summer peak demands for the New York Control Area for the years 2014 through 2024.[309, 310] The top panel of Figure A-99 shows the amount of capacity that entered or exited the market during each year.[311] Generator retirements in the coming years will include units that plan to operate as winter-only resources.

Figure A-99: Installed Summer Capacity of Generation by Prime Mover
2015 – 2025



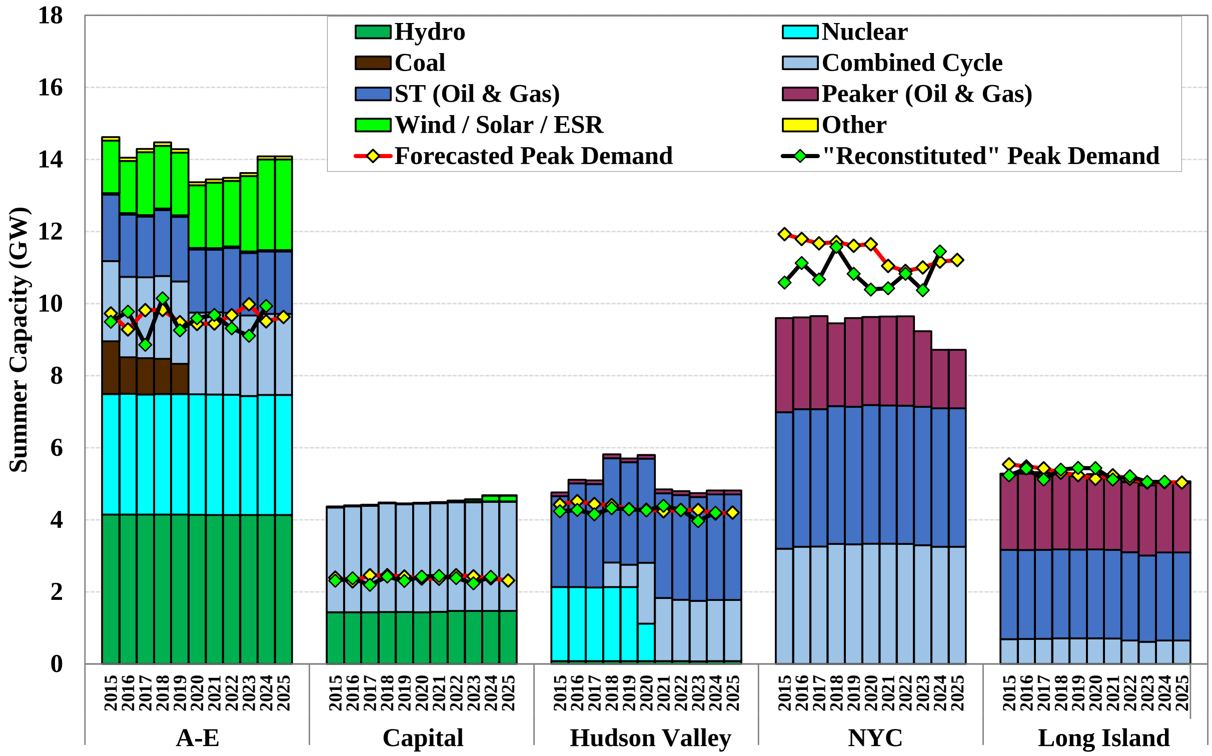
309 Forecasted peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. Capacity is based on the Gold Book and Generator Status Update files.

310 Reconstituted peak demand values in Figure A-99 and Figure A-100 include demand reductions from NYISO and utility-based programs.

311 Both the annual capacity and capacity from new additions from wind resources are given for units with both ERIS and CRIS rights. ERIS-only wind units do not appear in this chart as capacity resources.

Figure A-100 shows a regional distribution of generation resources and the forecasted and actual non-coincident peak demand levels for each region over the same timeframe. The installed capacity shown for each year is based on the summer rating of resources that are operational at the beginning of the Summer Capability Period of that year (i.e., capacity online by May 1 of each given year).

Figure A-100: Installed Summer Capacity of Generation by Region and by Prime Mover
2015 – 2025



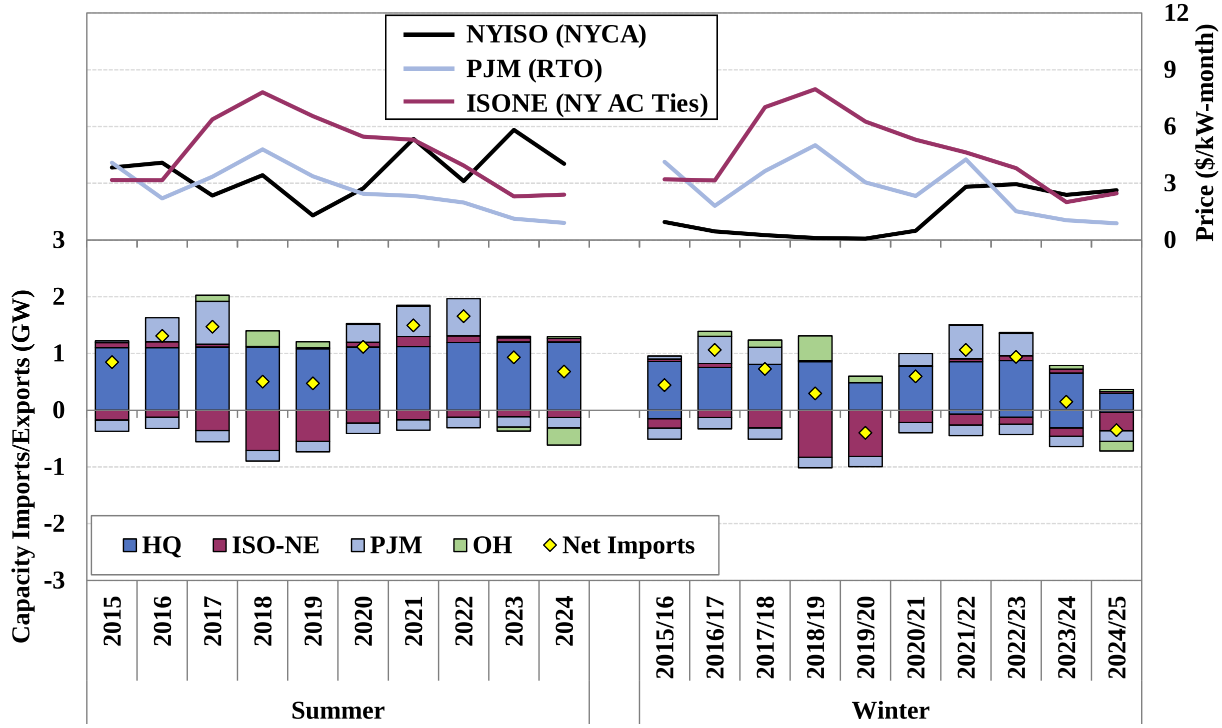
B. Capacity Imports and Exports

Figure A-101: NYISO Capacity Imports and Exports by Interface

NYISO procures a portion of its installed capacity from neighboring regions, and some internal capacity is sold to neighboring regions. Figure A-101 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Summer 2015 through Winter 2024/25 along with capacity prices in the New York Control Area and its neighboring control areas, including Hydro Quebec ("HQ"), Ontario ("OH"), PJM, and ISO-NE.[312] The capacity imported from each region is shown by the positive value stacked bars, while the capacity exported from NYCA is shown as negative value bars. The capacity prices shown in the figure are: (a) the NYCA spot auction price for NYISO; (b) the RTO price in the Base Residual Auction for PJM; and (c) the NY AC Ties price in the Forward Capacity Auction for ISO-NE.

312 The values for Winter 2023/24, reflect average net imports and average prices through February 2024.

Figure A-101: NYISO Capacity Imports and Exports by Interface
Summer 2015 – Winter 2024/25



C. Derating Factors and Equivalent Forced Outage Rates

The UCAP of a resource is equal to its installed capacity adjusted to reflect its expected availability, as measured by its Equivalent Forced Outage Rate on demand ("EFORd"). A generator with a high frequency of forced outages over the preceding two years' Capability Periods (i.e. a unit with a high EFORd) would not be able to sell as much UCAP as a reliable unit (i.e. a unit with a low EFORd) with the same installed capacity. For example, a unit with 100 MW of tested capacity and an EFORd of 7 percent would be able to sell 93 MW of UCAP.[313] This gives suppliers an incentive to perform reliably.

The locality-specific derating factors are used to translate ICAP requirements into UCAP requirements for each capacity zone. The NYISO computes the derating factor for each capability period based on the weighted-average EFORd of the capacity resources that are electrically located within the zone. For each Locality, a derating factor is calculated from the two most recent like-Capability Period average EFORd values of resources in the Locality in accordance with Section 4.5 of the NYISO's Installed Capacity Manual.[314]

313 The variables and methodology used to calculate EFORd for a resource can be found here.

314 The Derating Factor used in each six-month capability period for each Locality may be found here.

Table A-14: Historic Derating Factors by Locality

Table A-14 shows the derating factors the NYISO calculated for each capacity zone from Summer 2020 onwards. Derating factors tend to be highest in regions with the most intermittent capacity and most volatile year-over-year in regions with older generation fleets.

Table A-14: Derating Factors by Locality
Summer 2020 – Winter 2024/25

Locality	Summer 2024	Summer 2023	Summer 2022	Summer 2021	Summer 2020	Winter 2024/25	Winter 2023/24	Winter 2022/23	Winter 2021/22	Winter 2020/21
G-I	13.49%	11.82%	7.63%	5.45%	5.77%	12.49%	10.62%	10.39%	8.41%	3.21%
LI	8.66%	7.29%	6.27%	4.91%	6.91%	9.36%	10.66%	10.31%	7.21%	5.91%
NYC	4.62%	1.64%	3.26%	2.69%	3.51%	4.13%	4.12%	3.41%	2.48%	2.70%
A-F	18.03%	14.48%	14.20%	13.27%	11.78%	18.68%	13.16%	10.70%	11.36%	9.63%
NYCA	13.21%	10.14%	9.78%	8.77%	8.30%	13.46%	10.39%	8.91%	8.40%	6.61%

Figure A-102 to Table A-15: Unavailable Capacity to RTC & RTD from Various Technologies in Summer Capability Periods

The NYISO tariff describes a DMNC testing process to determine the ICAP ratings for traditional generators such as nuclear units, combined cycles, steam turbines, and peaking facilities. The process is similar for each of these unit types, but it takes into consideration certain technology-specific characteristics in fine tuning testing obligations.[315] One such technology-specific obligation that exists is for "internal combustion, combustion units, and combined cycles" to temperature-adjust their DMNC test results based on an output factor curve that is dependent on one variable, ambient air temperatures, and a seasonal peak temperature rating determined by the previous Transmission District peak conditions across the most recent four like-Capability Periods. Functionally, this tends to cause the ICAP ratings for these unit types during the summer Capability Periods to be lower than the value at which they test since tests are often done at cooler temperatures than the seasonal peak.

Figure A-102 shows the estimated ICAP that was functionally unavailable to the market in peak conditions in the summer of 2024 on fossil-fueled and nuclear units by the following categories:

- Emergency MW – Capacity offered above a generator's normal upper operating limit ("UOLn") that is only available under NYISO Emergency Operations.[316]
- Low ISO Conditions – the amount of capacity unavailable due to actual peak summer temperatures that exceeded the four-year average peak temperature adjustment values used in the DMNC process. The effects of air temperature of generator capability are determined based on an output factor equation certified by each plant with the NYISO.[317]
- Other Ambient – the amount of capacity explicitly derated from combined cycle and peaking units that cannot be explained by air temperature conditions.

315 See Section 4.2 of the ICAP Manual.

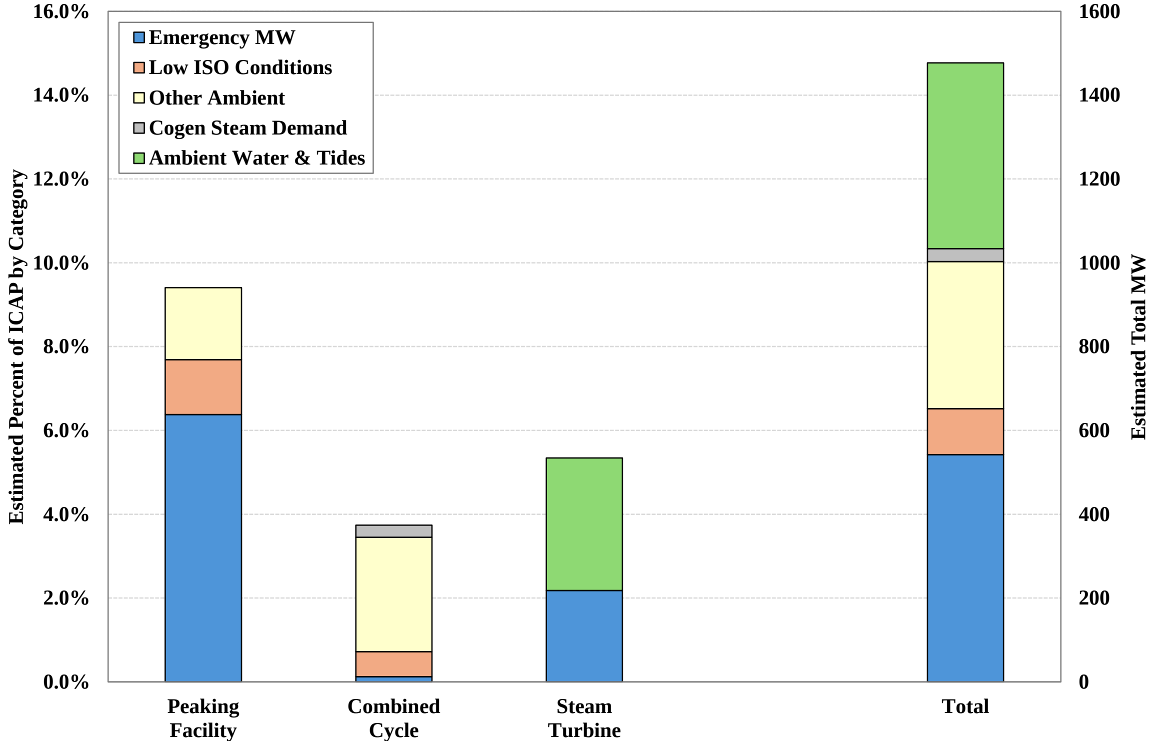
316 See NYISO Emergency Operations Manual.

317 See NYISO ICAP Manual Attachment M for further details on output factor equations.

- Cogen Steam Demand – the amount of capacity unavailable from cogeneration resources with active host steam load obligations.
- Ambient Water & Tides – the amount of capacity explicitly derated from once-through cooled fossil and nuclear steam turbines due to ambient water temperatures and tides.

Values for each category are presented as percentages of total by unit type on the primary axis with the total ICAP across all resources summed in the secondary axis.

Figure A-102: Functionally Unavailable Capacity from Fossil-Fuel and Nuclear Generators
Summer 2024



Most of the ICAP identified in Figure A-102 is sold into the market. NYISO filed tariff revisions that will start to reduce DMNC values in the 2025/26 and 2026/27 Capability Years to address the following:

- Relative humidity will be accounted for in the ambient adjustment for air-cooled generators with certain evaporative cooling equipment.
- Summer DMNC tests of once through cooled nuclear and fossil steam turbines will be conducted in either July or August between 10 AM – 10 PM so that ambient water temperatures during the test will be more consistent with those at peak conditions.
- The Capacity Limited Resource designation will be sunset and the day-ahead offer obligation on ICAP suppliers will be set by the UOLn.[318]

318 Exemptions for capacity related to duct burners of combined cycles and peak firing of block-loaded peakers are included until the market models are improved to enable offering and scheduling of those components.

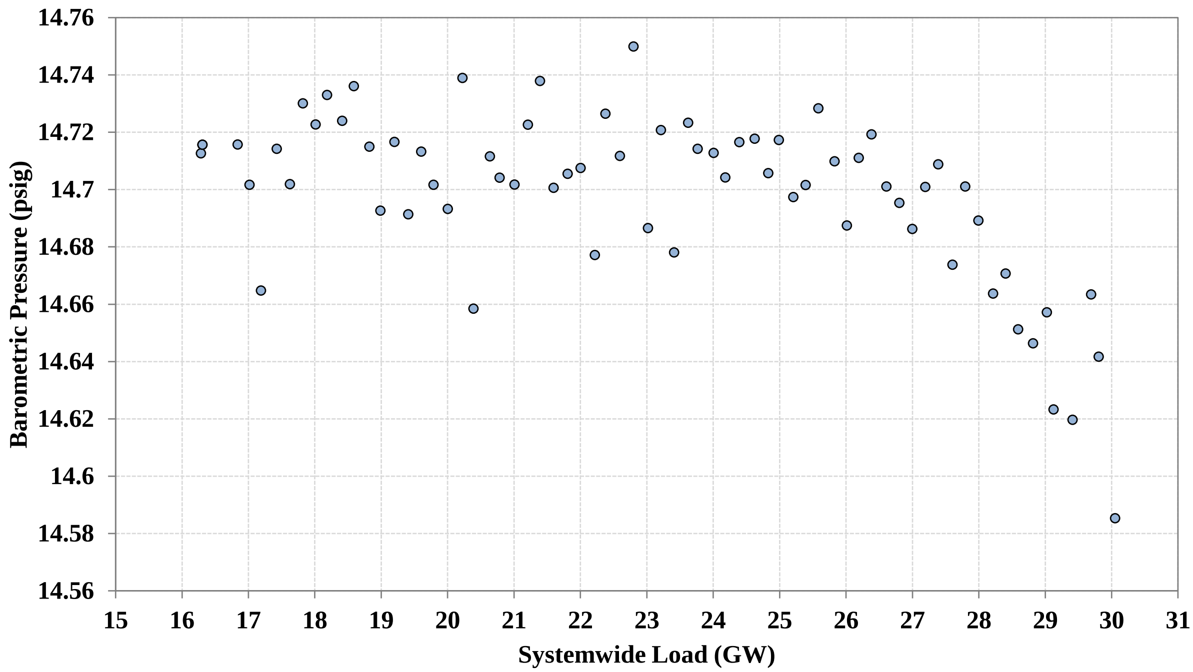
These changes should improve capacity accreditation for conventional generators, though additional improvements are necessary to accurately account for expected ambient-adjusted capability of resources impacted by ambient water temperature conditions and barometric pressure conditions (which are discussed below).

Other Ambient – Barometric Pressure on Combustion Turbines

Barometric pressure affects the power output and efficiency of certain generation technologies, particularly CTs in simple cycle and combined cycle configurations. This is because air density falls as barometric pressure drops leading to lower mass flow of air through the CT.[319] Therefore, barometric pressure and the CT maximum output are correlated. Barometric pressure conditions are inversely correlated with NYISO load values on the warmest summer days. Figure A-103 shows the relationship between barometric pressure values at the generator locations for all generators with at least one CT in the NYISO versus the systemwide hourly demand from each hour of Summers 2022-2024. Each point represents the average barometric pressure across all generators during hours where the real-time system demand was within defined 200 MW buckets. For example, the first point shows the average barometric pressure when systemwide demand was between 16.3 GW and 16.5 GW was 14.71 psig (y-axis) with an average system load in that range of 16.31 GW (x-axis).

Figure A-103: Relative Humidity vs Systemwide Load at Generator Locations

2022 - 2024



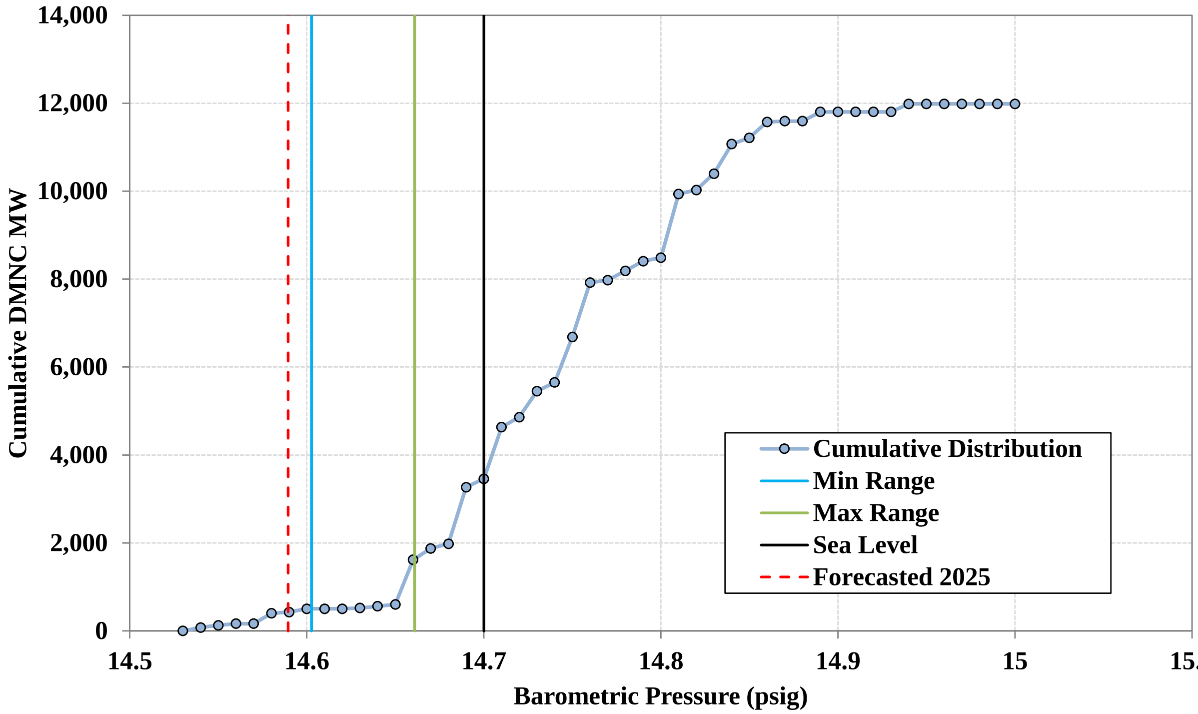
319 See: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

This analysis shows that average barometric pressure does not vary much under most load conditions.[320] Under summer peak load conditions when demand surpassed roughly 27 to 28 GW, the air was less dense than average. Therefore, CT capability at peak conditions will, on average, be lower at peak conditions than throughout the rest of the summer due to predictably lower pressure conditions.

The next figure evaluates the average barometric pressure at each generating station in NYISO with at least one CT during its DMNC test in the 2024 Summer Capability Period. The combined DMNC MW submitted from these tests is given by the blue line, which shows how much capacity was tested at barometric pressures at or below the value given on the x-axis. The vertical green line shows the maximum hourly barometric pressure at any one generating station during those load conditions in Summer 2024. The vertical blue line shows the minimum hourly barometric pressure from any one generator during those same load conditions. The barometric pressure corresponding to sea level (14.7 psig) is shown with the black vertical line as a point of reference. Finally, we estimated the expected barometric pressure at the forecasted peak demand levels for Summer 2025 from the 2024 Goldbook using the relationship between pressure and high load conditions from each generator location.

Figure A-104: Cumulative Capacity by Barometric Pressure during DMNC Tests

2024 Summer DMNC Tests



320 Warmer air is less dense which means barometric pressure predictably drops as temperatures rise. See https://www.noaa.gov/jetstream/atmosphere/air-pressure#:~:text=This%20change%20in%20pressure%20is%20caused%20by,are%20farther%20apart%20than%20in%20cooler%20air.

Roughly 96.5 percent of all capacity from those generators that are impacted by barometric pressure conditions came from DMNC tests that occurred at pressure conditions that were more favorable than what ought to be anticipated at the 2025 forecasted peak demand levels. The seasonal DMNC rating is meant to quantify the capability of the CT at peak load conditions, i.e., when air temperatures are highest. However, the DMNC testing procedures allow testing during any hours of June through mid-September for combined cycle units and CTs. Most generators test at optimal barometric conditions (i.e., cool, sunny days when barometric pressures are at or above sea level). Hence, total installed capacity is likely overstated since no barometric pressure adjustment is included in the requirements of ambient conditions dependent resources.

Table A-15 summarizes the MMU's estimates of overvalued ICAP ratings from barometric pressure-impacted generators based on: (a) forecasted 2025 peak demand conditions[321] and (b) actual conditions during DMNC tests from each of the past three summers.[322] The relationship between station max output and barometric pressure used in this analysis was 10.34 percent per 1 psig change in pressure.[323] Since barometric pressure predictably falls with hotter air temperatures and most DMNC tests occur at milder conditions, the total impact of barometric pressure on functionally unavailable capacity is estimated at 234.4 MW from the 2024 Summer DMNC tests, with nearly 78 percent of that value coming from combined cycle stations.

Table A-15: Overestimate of ICAP due to Barometric Pressure by Unit Type
Based on DMNC tests from 2022-2024 at Forecasted 2025 Peak Loads

Type	2022	2023	2024
CC	180.6	191.0	182.8
Peaker	43.9	46.7	51.6
Total	**224.5**	**237.7**	**234.4**

Although NYISO has filed tariff changes to improve the accuracy of DMNC values, additional improvements are necessary to accurately account for expected ambient-adjusted capability of resources impacted by ambient water temperature (shown in Figure A-102) and barometric pressure conditions (shown in Table A-15).

Water temperatures tend to rise steadily over the summer. Temperatures are predictably lower in early-July than in late-July and mid-August. Insofar as the peak conditions occur further into the summer months, tests conducted in early-July will likely underestimate the water temperature impact on these resources. Additionally, there is more than 9 GW of once through cooled fossil-fired steam turbine capacity in southeast NY which is impacted by tidal conditions. Ambient-adjusted capability is highest at high tide and can fall as the tides drop. Any DMNC test conducted at above-average tidal conditions is likely to minimize or mask the effects of tides.

321 See: https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf

322 We pull weather conditions for each generator location based on data at the ZIP Code level.

323 See Figured 10 of: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

Barometric pressure affects the capability of CTs in a predictable way with higher pressures allowing for increased CT output. Hot air tends to be lower pressure than cooler air. Since most generators with one or more CTs conduct DMNC tests on mild, high-pressure days in the early or late summer, actual capability tends to be lower at peak conditions. Therefore, we recommend that:

- Ambient water & tidal dependent resources adjust DMNC test results to peak temperature and average tide conditions using an approach similar to what the NYISO has chosen for ambient air temperature and humidity conditions dependent resources; and
- Generators that are impacted by barometric pressure make an adjustment from DMNC test conditions to an ISO-determined expected value pressure value implicit in the peak load forecast.

D. Capacity Market Results

Figure A-105 – Figure A-108: Capacity Sales and Prices

Figure A-105 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs") and sales from SCRs.[324] The hollow portion of each bar represents the In-State capacity in each region not sold (including capacity not offered) in New York or in any adjacent market. The line indicates the capacity requirement for each Capability Period for NYCA. Additionally, the figure shows sales from external capacity resources into NYCA and exports of internal capacity to other control areas. The upper portion of the figure shows clearing prices in the monthly spot auctions for NYCA (i.e., the Rest of State).

The capacity sales and requirements in the figure are shown in the UCAP terms, which reflect the amount of resources available to sell capacity. The changes in the UCAP requirements are affected by changes in the forecasted peak load, the minimum capacity requirement, and the Derating Factors. To better illustrate these changes over the period examined, the figure also shows the forecasted peak load and the ICAP requirements.

Figure A-106 to Figure A-108 show capacity market results in New York City, Long Island, and the G-J Locality for the past four six-month Capability Periods. These charts display the same quantities as Figure A-105 does for the NYCA region and compare the spot prices in each Locality to the Rest-Of-State prices.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

324 Special Case Resources ("SCRs") are Demand Side Resources whose Load is capable of being interrupted upon demand, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the NYISO.

Figure A-105: UCAP Sales and Prices in NYCA
May 2023 to February 2025

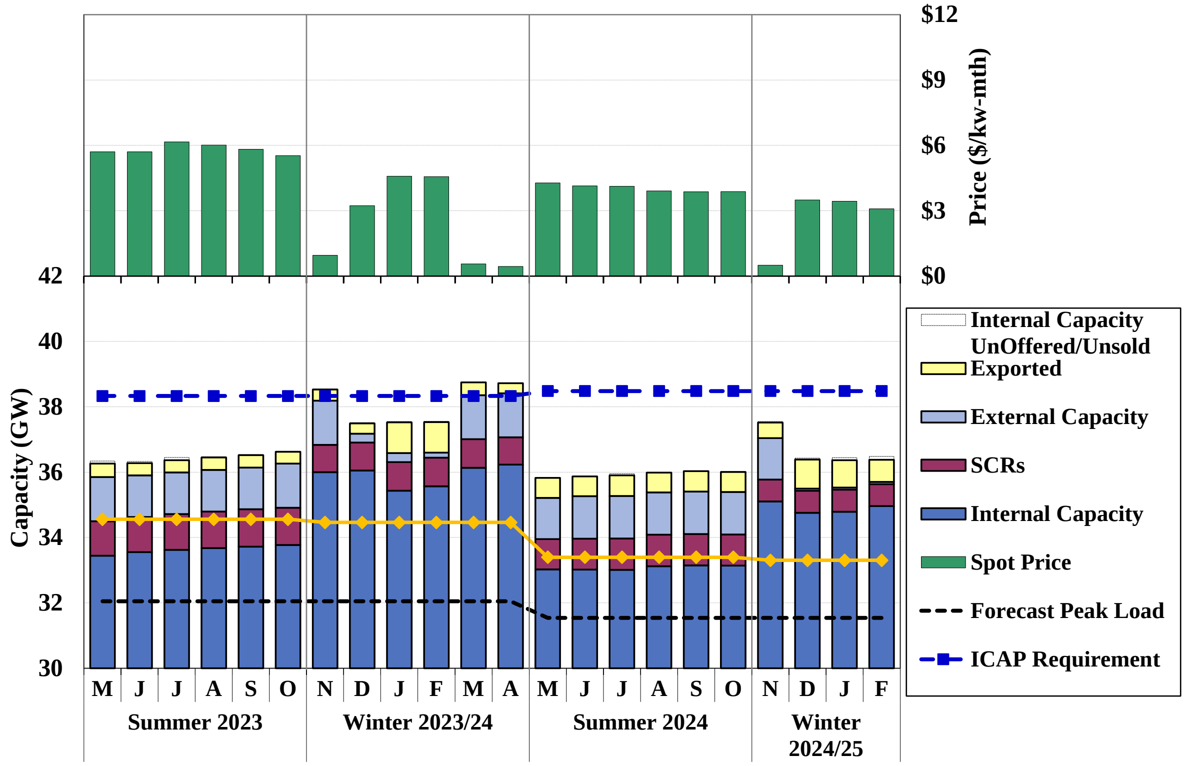


Figure A-106: UCAP Sales and Prices in New York City
May 2023 to February 2025

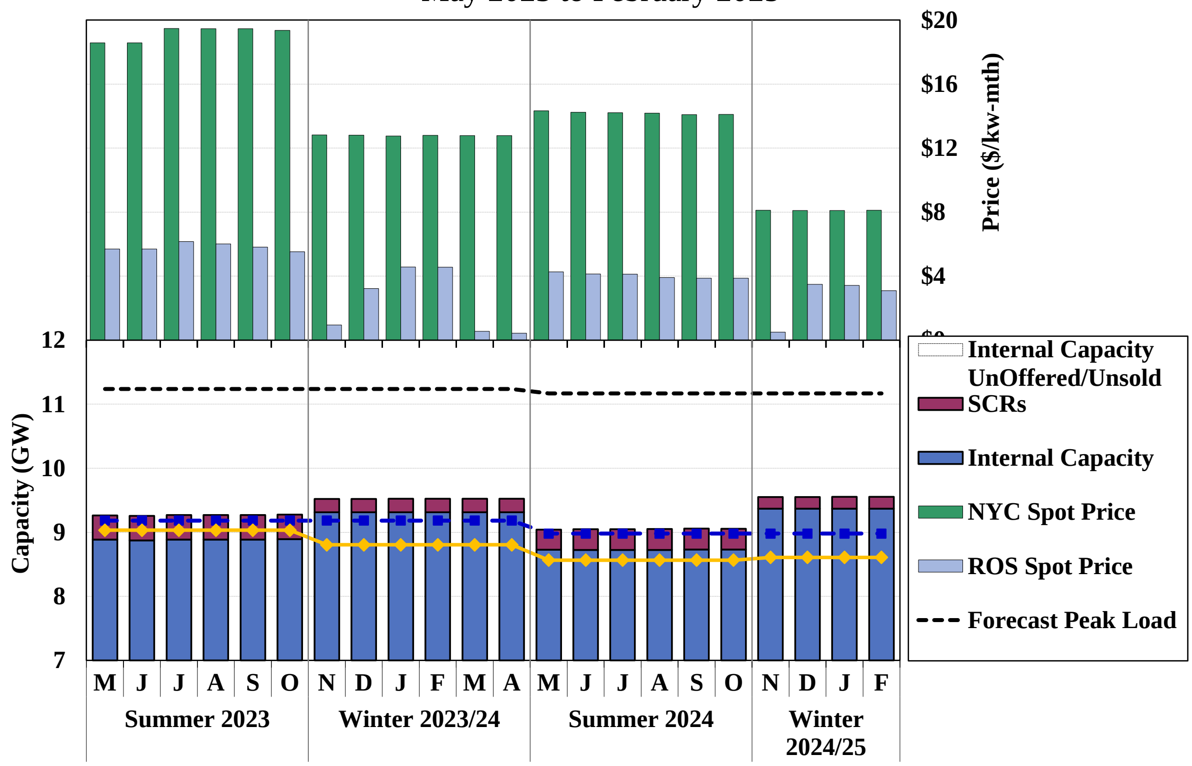


Figure A-107: UCAP Sales and Prices in Long Island
May 2023 to February 2025

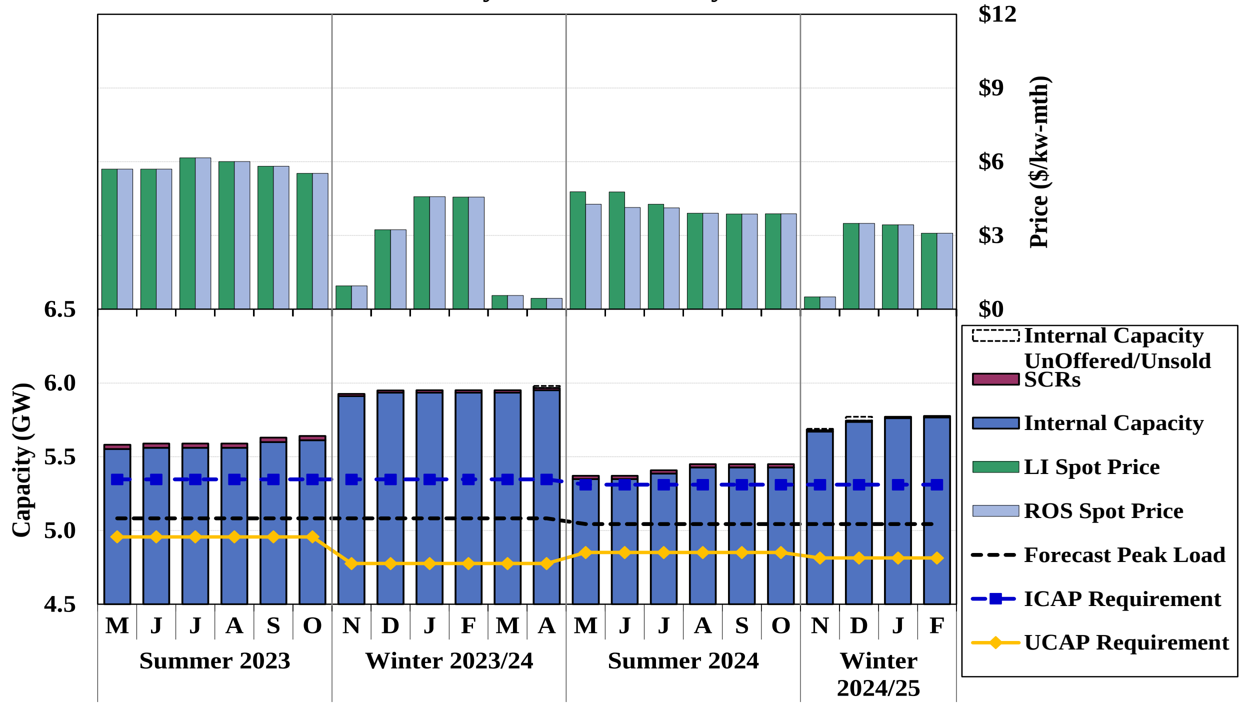


Figure A-108: UCAP Sales and Prices in the G-J Locality
May 2023 to February 2025

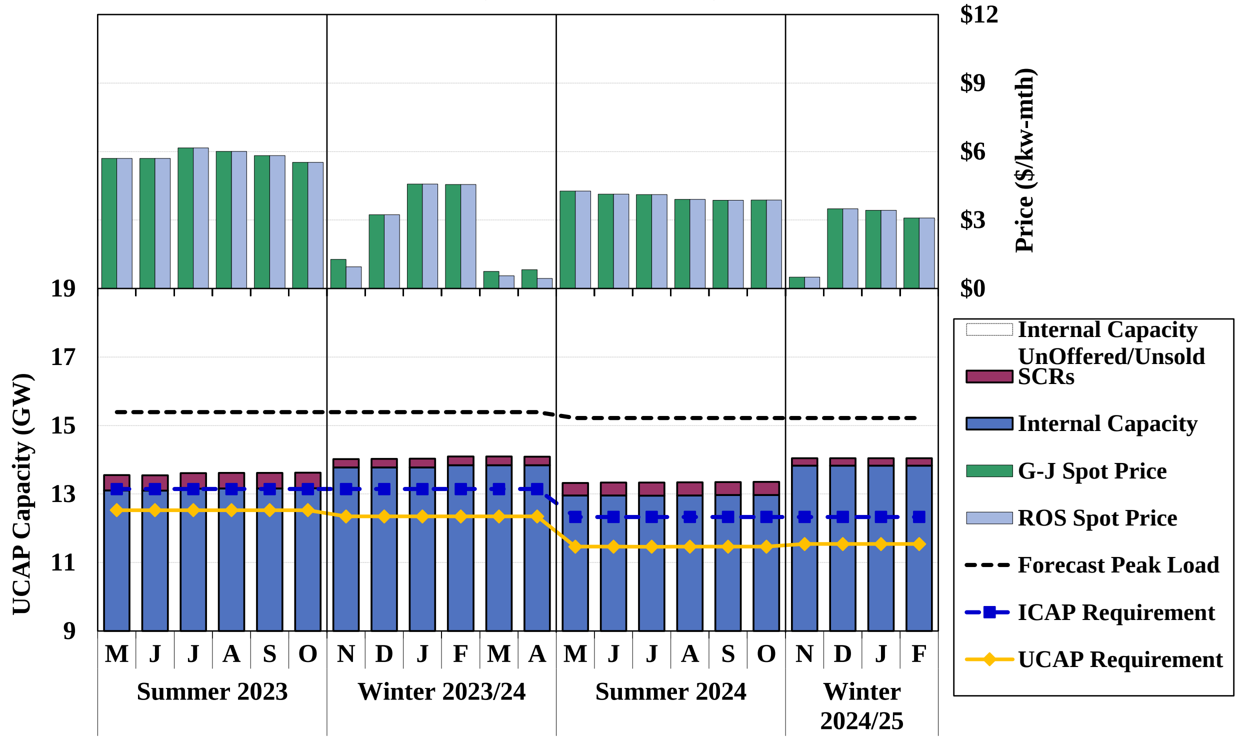
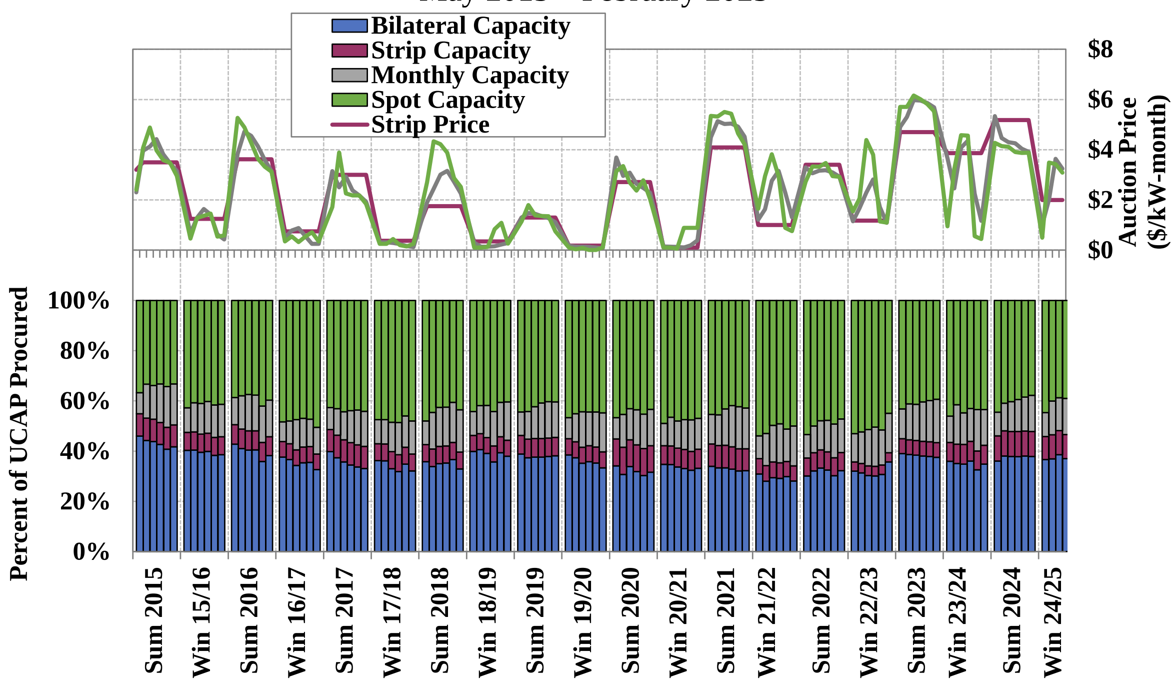


Figure A-109: Capacity Procurement by Type and Auction Price Differentials

Figure A-109 describes the breakdown of capacity procured by mechanism (bilateral markets, strip auctions, monthly auctions and spot auctions) and the resulting prices for various auctions over the last ten Capability Years. Bilateral prices are not reported to the NYISO and are not included in this figure. The stacked columns correspond to the left vertical axis and indicate the percentage of total capacity procured via the four procurement methods for each month in a given Capability Period. The top panel of the chart (corresponding to the left vertical axis) shows the monthly prices for each of the spot, monthly and strip auctions since the Summer 2015 capability period on a dollar-per-kilowatt-month basis.

Figure A-109: Auction Procurement and Price Differentials in NYCA

May 2015 – February 2025



E. Resource Adequacy Modeling Framework and Assumptions

Potomac Economics' Resource Adequacy Model (PE-RAM) is a program designed to evaluate the impacts of market design proposals related to resource adequacy. It is an hourly chronological model that considers load forecast uncertainty, generator outages, transmission limitations, intermittent resource profiles, and energy storage limitations. PE-RAM is not designed to replicate outcomes of other programs such as GE MARS and is not used to perform absolute assessments of the NYISO system's reliability. Instead, it is designed to allow flexible changes to modeling rules and assumptions for use in examining the impact of market design changes. PE-RAM has the following major components:

- Hourly model: the simulation consists of a number of run years, each of which simulates load and supply in all 8,760 hours of the year. Each run year considers a different combination of load and generator availability assumptions.

- Load model: each run year simulates an hourly load pattern and peak load level reflecting a particular level of load forecast uncertainty.
- Generator model: summer and winter generation capacity and outage states are represented at a zonal level. Zonal outage scenarios are based on probabilistic simulation of aggregate outages of generators within each area.
- Transmission model: the simulation represents individual areas connected by transmission limits in a "pipe and bubble" framework. When an area lacks sufficient available capacity to meet local load, it imports supply from other areas until transmission limits are binding.
- External areas: external areas are currently not modeled directly. Instead, emergency import patterns representing variations in available external supply are modeled in each run year.
- Intermittent resources: intermittent generators are modeled using an 8,760-hour capacity factor profile for each resource type in each zone. Renewable profiles may vary by run year.
- Gas-only resources: generators that rely on natural gas are subject to reduced availability in winter based on a relationship between non-firm gas availability and daily winter peak load.
- Energy limited resources: resources such as battery storage are modeled with energy limitations and are dispatched when needed to avoid load shedding. Energy limited resources recharge during off-peak hours if sufficient supply is available on the system. The simulation uses heuristics to determine the sequence of discharge of energy limited resources, generally deploying resources with more remaining duration or in lower-value zones first.

PE-RAM produces the following outputs for use in market design evaluations:

- Expected Unserved Energy (EUE): each simulation calculates the total MWh of unserved energy, (UE) in each run year. UE occurs when there is insufficient available generation to serve load or when transmission constraints limit the ability of supply to flow to load. Unserved energy across run years is weighted by probability values associated with the assumptions for that run year. The sum of these values is the total EUE of the simulation.
- Marginal Reliability Impact (MRI): for each resource type and each zone, the simulation calculates an MRI value. This is the change in EUE resulting from a small addition of the examined resource.
- Capacity Requirements: the simulation calculates IRM and LCR values using an optimizer approach that minimizes investment costs to satisfy a target level of EUE. Net CONE values are defined for areas included in the simulation. For those areas, the MRI and Cost of Reliability Improvement (CRI, see section F of this appendix) is calculated after each simulation run. Perfect capacity is removed from areas with high CRI values and added to areas with low CRI values. This is repeated until EUE is equal to the target level and CRI values across zones converge (subject to tolerance criteria). The resulting zonal ICAP requirements are the total installed capacity plus positive or negative PCAP adders in each capacity region.

Table A-16 and Figure A-110 – Resource Adequacy Model Assumptions for Winter Accreditation Analysis

Section III.C discusses the potential impact of modeling winter fuel inventory depletion in reliability studies on capacity accreditation outcomes. We performed this analysis using PE-RAM with the following assumptions:

Table A-16: Resource Adequacy Model Assumptions for Winter Accreditation Analysis

Assumption	**Description**
Load	2024 Gold Book load forecast; load forecast uncertainty levels based on 2024/25 IRM Study. Gold Book BTM solar forecast modeled as resource separate from gross load.
Existing generation capacity	Summer and winter ICAP based on 2024 Gold Book. For 2030/31 run year, generator status changes of remaining units affected by DEC Peaker Rule and retirement of NYPA peaker plants in New York City were modeled. Fossil outage rates were modeled based on 2024 IRM Study.
New generation capacity (cumulative)	Solar PV: 17 GW (2030), 28 GW (2035) and 49 GW (2040) (including utility and BTM) Land Based Wind: 1.7 GW (2030), 3 GW (2035), 12 GW (2040) Offshore Wind: 2 GW (2030), 9 GW (2035), 12 GW (2040) Battery Storage: 4.5 GW (2030), 8.2 GW (2035), 14.3 GW (2040)
Intermittent generator capacity factors	Based on NYISO 2021 Outlook profiles derived from NREL data
Zonal topology	Simplified set of areas selected to capture major transmission constraints including A, BCE, D, F, G, HI, J, and K.
Transmission limits	Based on transmission limits after completion of AC PPTN projects from NYISO 2024 RNA MARS topology. For 2030/31, included upgrades based on estimated MARS limit impact of Long Island PPTN projects from NYISO Long Island PPTN study.
New HVDC Transmission	Included CHPE project as 1,250 MW injection into NYC in summer and 0 MW injection in winter. Included CPNY project as 1,300 MW link between zones BCE and J.
Firm Gas	Approx. 2,000 MW firm gas modeled in zones F-K in winter based on recent NYISO fuel surveys
External Assistance	Based on NYSRC 2023 EOP whitepaper
SCRs	Included based on 2024 enrollment levels

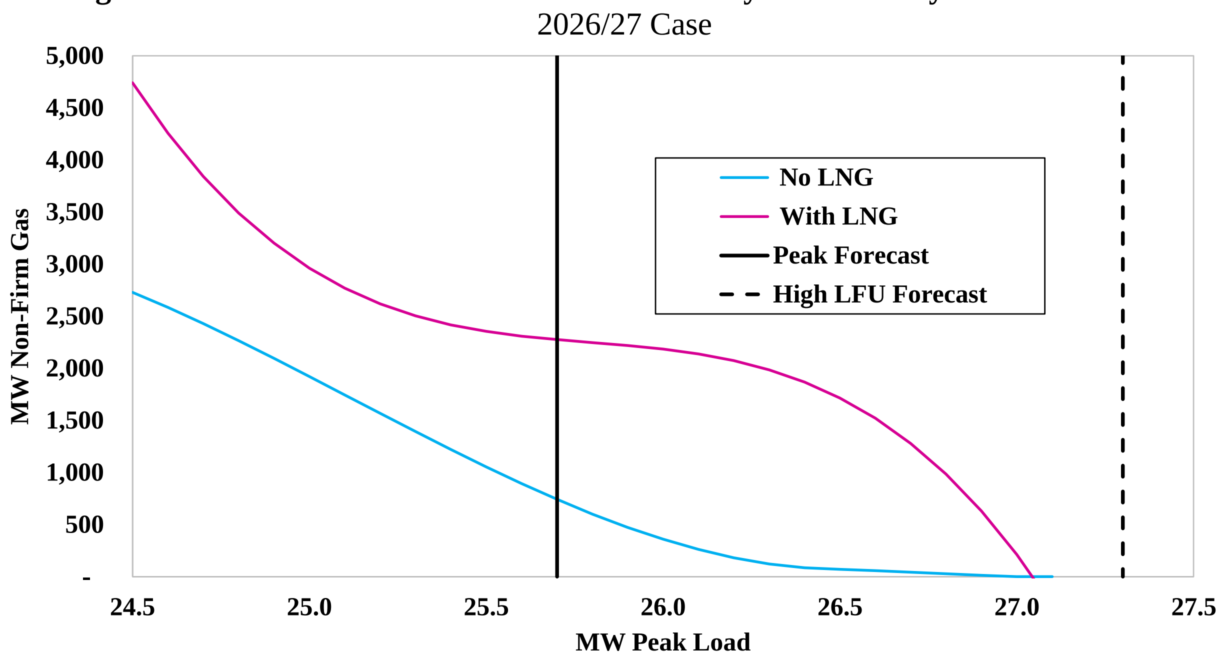
Our analysis of how accreditation could be affected by winter fuel security modeling used a modeling approach that tracks remaining oil inventories chronologically. We included the following modeling features in this analysis:

Oil inventories: We model oil and dual fuel generators as capable of generating up to their ICAP in winter, adjusted for forced outages. Each unit is modeled with a starting oil inventory and timeframe before spent fuel is replenished based on recent NYISO generator fuel surveys. Oil generators are dispatched by the model when non-fuel limited supply is insufficient to meet load. Each unit's inventory is tracked over time, and the unit becomes unavailable if the inventory reaches zero until replenishment occurs. The model employs a heuristic approach to the order in which oil units are dispatched. Units with larger inventories and more frequent replenishment are generally dispatched first, and units are held in reserve upon reaching low inventory unless needed to prevent load shedding. This approach is intended to simulate the expectation that units running short on fuel would submit higher energy market offers.

Non-Firm Gas: we modeled a relationship between daily winter peak load and daily maximum non-firm gas generation. Non-firm gas historically made available by LNG imports is netted out from the available gas supply. For future run years, the historically observed amount of non-firm gas at each load level is scaled up proportionate to growth in the winter peak load forecast, to account for higher projected load levels during the same weather conditions.

Figure A-110 below shows the modeled daily load-gas relationship for the 2026/27 capability year. The modeled winter peak load levels under the baseline forecast and an upper load forecast uncertainty level (based on Bin 2 load forecast uncertainty from the 2024 IRM Study).

Figure A-110: Modeled Non-Firm Gas Availability at each Daily Peak Load Level



F. Cost of Reliability Improvement from Additional Capacity

An efficient capacity market would signal for capacity to locate where it is most cost-effective to improve system reliability. In this subsection, we discuss a framework for measuring capacity prices relative to this objective and evaluate the effectiveness of NYISO market at meeting it.

Since the inception of NYISO, the installed capacity requirements have been primarily based on resource adequacy criteria, which require sufficient capacity to maintain the likelihood of a load shedding event in the NYCA below the prescribed level (i.e., 1 day in 10 years). Hence, the capacity price in a particular location should depend on how much capacity at that location would reduce the likelihood of load shedding in NYCA. Since implementing the downward sloping capacity demand curves in 2004, NYISO has used the cost of new entry as the basis for placing the demand curve sufficiently high to allow a hypothetical new entrant to recover its capital costs over an assumed project life. Hence, capacity markets should provide price signals that reflect: the reliability impact and the cost of procuring additional capacity in each location.

The Cost of Reliability Improvement ("CRI"), which is defined as the cost of additional capacity to a zone that would improve LOLE by 0.001, characterizes the value of additional capacity in a zone and captures the two key factors that should be considered while determining capacity prices. Under an efficient market design, the CRI should be the same in every zone under long term equilibrium conditions. This will reduce the overall cost of maintaining reliability and direct investment to the most valuable locations. To achieve these efficient locational capacity prices, the market should procure amounts of capacity in each area that minimize the cost of satisfying the resource adequacy standard.

NYISO's methodology for determining the LCRs ("Optimized LCRs Method") seeks to minimize the total procurement cost of capacity under long term equilibrium while conforming to: (a) an LOLE of less than 0.1 days per year, (b) the NYSRC-determined IRM, and (c) transmission security limits ("TSL") for individual Localities. The "Optimized LCRs Method" minimizes procurement costs (i.e., capacity clearing price times quantity) rather than investment costs (i.e., the marginal cost of supply in the capacity market). Minimizing procurement costs is inefficient because it does not necessarily select the lowest cost supply to satisfy reliability. Minimizing investment costs is efficient because it selects the lowest cost resources just as the energy and ancillary services markets select the lowest cost resources to satisfy load and ancillary services requirements.

Table A-17: Cost of Reliability Improvement

Table A-17 shows the CRI in each zone based on the long-term equilibrium that is modeled in the demand curve reset process. Under these conditions, each locality has a modest excess (known as its "Excess Level") so that the system is more reliable than the 0.1 LOLE minimum criteria.[325] An Excess Level is assumed so that the demand curve in each area is set sufficiently

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325 The demand curve reset process is required by tariff to assume that the average level of excess in each capacity region is equal to the size of the demand curve unit in that region. The last demand curve reset assumed proxy units of approximately 200 MW (ICAP) in each area. For the MARS results discussed in this section, the base case was set to the Excess Level in each area.

high to ensure the system never exceeds the 0.1 LOLE criteria. This modest excess results in an LOLE of 0.066 in the 2025/26 Capability Year. The table shows the following for each area:

- *Net CONE of Demand Curve Unit* – Based on the Net CONE curves filed by NYISO for the 2025/2026 Capability Year, converted to UCAP using the 2025/26 CAF values.
- *NYCA LOLE at Excess Level in Demand Curve Reset* – This is a single value for NYCA that is found by setting the capacity margin in each area to the Excess Level from the last demand curve reset.
- *LOLE from 100 MW UCAP Addition* – The estimated LOLE from placing 100 MW of additional UCAP in the area.[326]
- *Marginal Reliability Impact ("MRI")* – The estimated reliability benefit (reduction in LOLE) from placing 100 MW of additional UCAP in the area. This is calculated as the difference between the NYCA LOLE at Excess Level and the LOLE from adding 100 MW of UCAP to the area.
- *Cost of Reliability Improvement ("CRI")* – The annual levelized investment cost for a 0.001 improvement in LOLE from placing capacity in the area.[327, 328] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

Table A-17: Cost of Reliability Improvement

2025/26 Capability Year

Locality/Zone	Net CONE of Demand Curve Unit *$/kW-yr*	NYCA LOLE at Excess Level	LOLE with 100 MW UCAP Addition	Marginal Reliability Impact *ΔLOLE per 100MW*	Cost of Reliability Improvement *M$ per 0.001 ΔLOLE*
NYCA					
A	$61		0.061	0.0053	$1.2
B	$61		0.061	0.0053	$1.2
C	$61		0.061	0.0051	$1.2
D	$61		0.061	0.0051	$1.2
E	$61		0.061	0.0052	$1.2
F	$61		0.061	0.0051	$1.2
G-J Locality		0.066			
G	$62		0.061	0.0051	$1.2
H	$62		0.061	0.0053	$1.2
I	$62		0.061	0.0053	$1.2
NYC					
J	$201		0.060	0.0059	$3.4
Long Island					
K	$83		0.056	0.0097	$0.9

326 These values were obtained by starting with the system at Excess Level with an LOLE of 0.066 and calculating the change in LOLE from a 100-MW perfect capacity addition in each area.

327 For example, for Zone F: $61/kW-year × 1000kW/MW ÷ (0.0053 LOLE change/100MW) × 0.001 LOLE change = $1.2 million.

328 Note, this value expresses the marginal rate at which LOLE changes from adding capacity when at the Excess Level. However, the actual cost of improving the LOLE by 0.001 might be somewhat higher since the impact of additional capacity tends to fall as more capacity is added at a particular location.

Figure A-111 and Figure A-112: Cost and CRI Curves in LCR Optimizer

Figure A-111 and Figure A-112 illustrate how the current design of the LCR Optimizer contributes to volatility and inefficient outcomes. Both figures compare the marginal cost of capacity for the 2022/23 capability year based on two formulations:

- *Investment cost minimization* – This uses the Net CONE curves to represent marginal investment cost.[329] These are shown in the top panel of each figure, which are monotonic upward-sloping marginal cost curves. These investment costs include the categories of costs that could be saved by procuring capacity more efficiently.
- *LCR Optimizer formulation* – The marginal cost function at each location is derived assuming NYISO minimizes overall consumer costs.[330] In the bottom panel of each figure, these non-monotonic marginal cost curves are shown to be discontinuous with irregular *downward* steps because the marginal consumer cost is strongly affected by slight changes in the steepness of Net CONE curve steps.[331] For example, Figure A-111 shows that if the LCR in Zone J rises from 80.6 to 86.6 percent, the Net CONE rises just 4.4 percent, while the corresponding marginal consumer cost curve falls by 24.0 percent.

For each locality in each formulation, Figure A-111 shows the marginal cost of capacity per kW-year, while Figure A-112 shows the CRI curve. Each CRI curve equals the marginal cost curve from Figure A-111 divided by the marginal reliability impact of capacity in the locality.[332] [333] Thus, the CRI curve is the marginal cost of capacity per unit of LOLE improvement. The red diamonds indicate simulated LCRs determined using the LCR Optimizer cost function.

In Figure A-112, the bottom panel illustrates how the LCR Optimizer seeks a solution that equalizes CRI values across localities while satisfying the LOLE criterion, IRM, and TSLs.[334] However, because the Optimizer calculates the marginal cost of capacity based on consumer costs, it relies on CRI curves that are not monotonic and may produce similar values for multiple different LCRs. Ultimately, this raises the following concerns:

- Because the Optimizer computes each locality's CRI in a way that produces the same value at multiple different LCRs, changes in model assumptions may lead to unpredictable and volatile changes in LCRs.

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329 This is because the first-order conditions of the investment cost minimizing optimization problem include the Net CONE functions in each location.

330 Marginal cost functions are derived from first order conditions of the consumer cost minimization problem.

331 Monotonicity is an important because it allows a solver to find the unique cost-minimizing solution more quickly, while non-monotonic cost functions make the problem non-convex and more difficult to solve.

332 We simulated MRI curves based on MARS-derived LOLE values for various combinations of LCRs. Because all possible combinations of LCRs cannot be feasibly tested, the MRI curves are approximate.

333 This chart assumes a fixed IRM at the 2022/23 level of 119.6 percent. With a constant IRM, the CRI in locality X is equal to: (marginal cost of adding capacity in locality X – marginal cost of adding capacity in NYCA) / (MRI of locality X – MRI of NYCA).

334 The simulated LCRs indicated by the red diamonds in Figure A-112 differ slightly from the actual 2022/23 LCRs because MRI was simulated using a limited number of MARS data points.

- The Optimizer does not produce efficient LCRs. In this example, the Zone K LCR is inefficiently low and the G-J Locality LCR is inefficiently high.

Figure A-111: Optimizer Cost Curves vs. Net CONE Curves
2022/2023 Capability Year

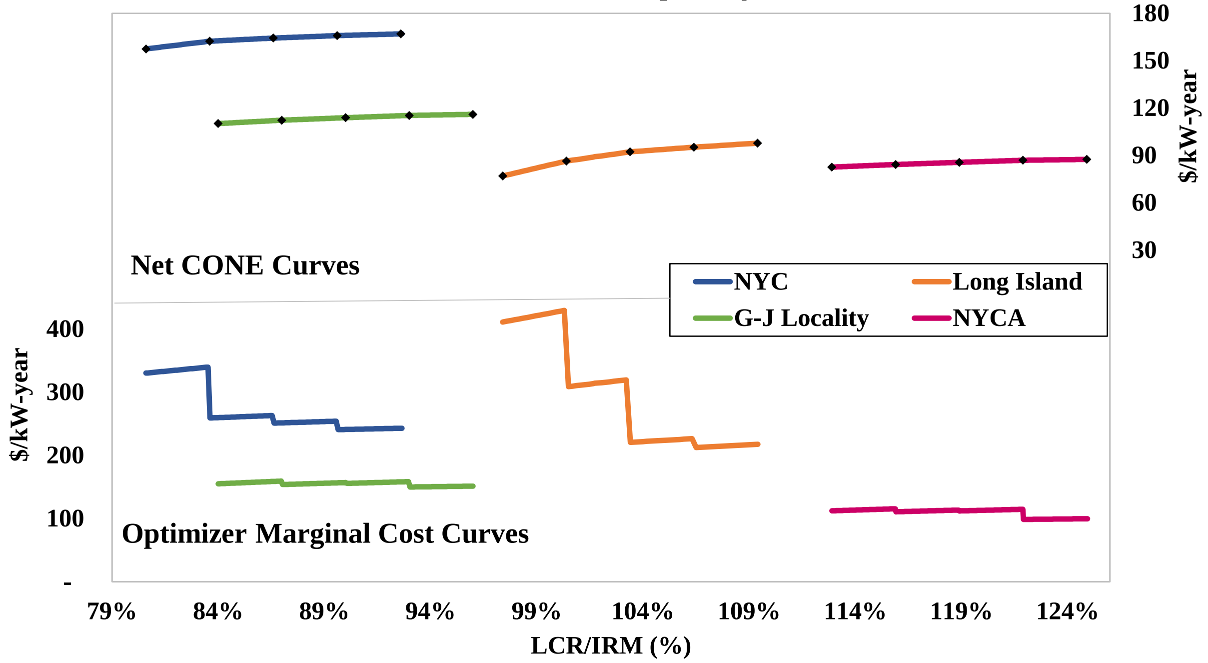
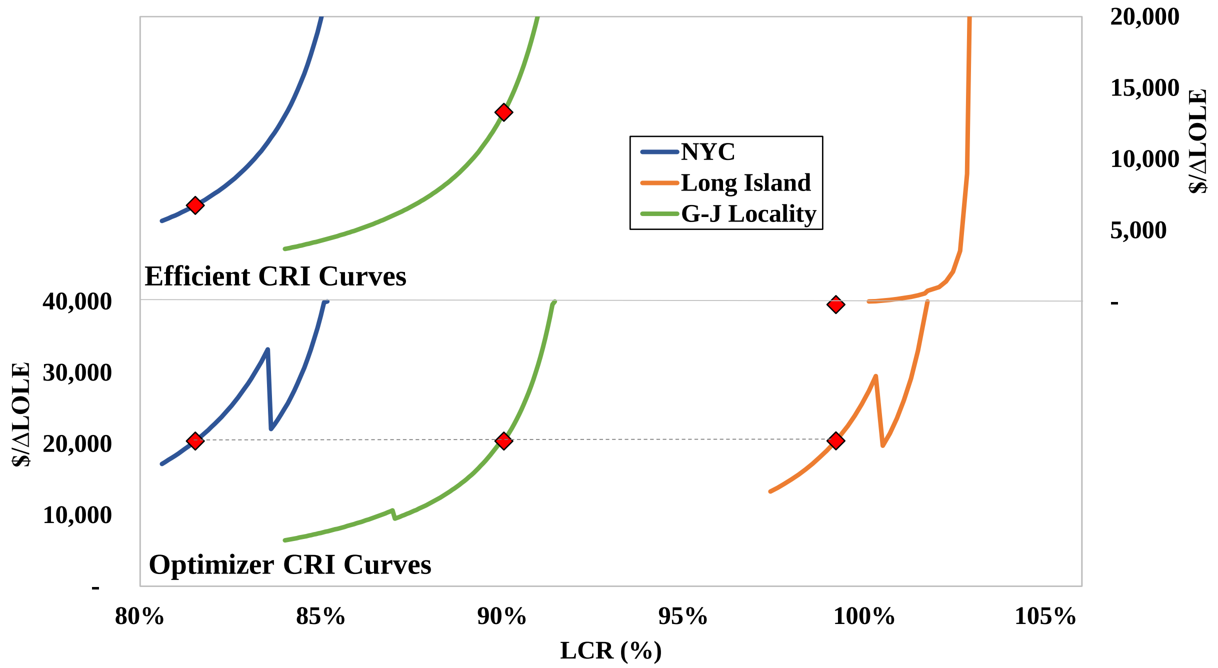


Figure A-112: Optimizer CRI Curves vs. Efficient CRI Curves
2022/2023 Capability Year



By contrast, the top panel shows how calculating the marginal cost of capacity based on investment costs produces uniformly upward sloping CRI curves, which allow the optimal solution to be found more quickly and reliably.

G. Mathematical Example of Capacity Constraint Pricing (CCP) for Capacity Resources

Section VIII.C of this report discusses our proposal to create a more granular set of capacity pricing zones. As part of this proposal, we recommend applying a financial Capacity Constraint Pricing (CCP) Credit or Charge to capacity payments of resources that positively or negatively impact aggregate deliverability between zones. We propose the following process to determine generator payments:

- Calculate a set of generator Capacity Constraint Pricing Factors (CCP Factors) for each interface between nested capacity zones (e.g. between two nested Import Zones or between and Import and Export zone). The CCP Factor is the amount by which an additional MW of output at a generator's location would cause the total amount of capacity deliverable over the interface to change. Each generator would be assigned a CCP Factor for each interface between the generator's zone and an adjacent zone. The CCP Factor can be positive, negative, or zero, indicating that the generator improves, harms or does not affect the interface limit.
- Calculate the zonal price difference for each interface between nested capacity zones. This is the difference in capacity prices between the zones connected by the interface.
- Each generator earns a total capacity payment equal to its UCAP MW times the sum of the zonal Capacity Price and generator's unique CCP Credit/Charge. The CCP Credit/Charge is calculated as the sum of the zonal price difference times the generator's CCP Factor for each constraint.

This subsection provides an example of how CCP Factors would be calculated and how they would affect resources' total capacity-related compensation.

Capacity Constraint Pricing Factors with One Transmission Constraint

Table A-18 through Table A-20 provide an illustrative example in which flows on the interface between an export zone and an import zone are limited by one constrained facility. The example includes five generators (units A-E), each of which have a different generator shift factor (GSF) on the most constrained facility that limits transfers over the interface (Line 1). The generators are classified as belonging to the import zone or export zone based on the direction of their GSF on Line 1. Load is assumed to be only in the import zone.

To estimate the interface limit from the export zone to the import zone, the output of all five generators is adjusted until the maximum amount of combined output in the export zone is reached, subject to constraints: (1) total generation equals total load, (2) flows on Line 1 cannot exceed its limit of 45 MW, and (3) each generator's output cannot exceed its maximum capacity. Flows on Line 1 are calculated as the product of each generator's scaled output level and its GSF (plus the load times the load shift factor). The maximum export zone output of 232.5 MW is reached by maximizing output from generators with lower GSFs on Line 1 (Units A, B and E) and reducing output from generators with higher GSFs on Line 1 (units C and D).

The export zone has 7.5 percent more capacity than its export limit (row (i)). We assume a 20 percent export zone demand curve length and a $10 per kW-month price in the import zone. Based on the export demand curve proposal discussed in Section VIII.C, this results in a capacity price of $6.2 per kW-month (62 percent of the import zone price) in the export zone. The discounted price in the export zone reflects the reduced value of capacity there due to the presence of a binding transmission constraint.

Finally, each unit's CCP Factor (row (n)) is calculated by increasing the maximum capacity of that unit by 1 MW and then recalculating the interface limit (row (g)) by adjusting all units to maximize output while maintaining the load balance and Line 1 limit. Units C and D each have a CCP Factor of zero, because additional capacity at these locations would not change the maximum amount of output that can occur in the export zone without violating the limit of Line 1 (however, additional capacity at unit C would increase the capacity surplus in the export zone and lower its price). Units A, B and E have positive CCP Factors because these units have low GSFs on Line 1, so additional capacity at these locations would allow a larger total amount of output in the export zone. For example, an additional MW at Unit A would cause the interface limit of 232.5 MW to increase by 0.5 MW.

Table A-18: Line and Unit Characteristics in One Line CCP Factor Example

Line Limits

Line 1 Limit (MW)	45

Unit Characteristics and Output Levels

Unit		A	B	C	D	E	Load	Total
Net Gen Capacity (MW)	(a)	100.0	100.0	50.0	100.0	100.0	-400.0	50.0
GSF	(b)	0.10	0.12	0.30	-0.10	-0.20	-0.10	
Zone	(c)	Export	Export	Export	Import	Import	Import	
Output Scalar	(d)	1.00	1.00	0.65	0.67	1.00	1.00	
Scaled Net Gen (MW)	(e) = (a) * (d)	100.0	100.0	32.5	67.5	100.0	-400.0	0.0
Impact on Line 1 (MW)	(f) = (b) * (e)	10.00	12.00	9.75	-6.75	-20.00	40.00	**45.00**

Table A-19: Calculation of Capacity Prices in One Line CCP Factor Example

Calculation of Zonal Prices

Export Zone Limit (MW)	(g) = Sum of (e) in export zone	232.50
Export Zone Supply (MW)	(h) = Sum of (a) in export zone	250.00
Export Zone Surplus	(i) = (h) / (g) - 1	7.5%
Export Demand Curve Length	(j)	20%
Import Zone Price ($/kW-mo)	(k)	10.00
Export Zone Price ($/kW-mo)	(l) = (k) * (1 - (i) / (j))	6.24
Zonal Price Difference	(m) = (k) - (l)	3.76

Table A-20: CCP Factors in One Line CCP Factor Example

CCP Factors and Credit/Charge		A	B	C	D	E
CCP Factor	(n)	0.50	0.45	0.00	0.00	0.25
Zonal Capacity Price	(o) = (k) or (l)	6.24	6.24	6.24	10.00	10.00
CCP Credit	(p) = (m) * (n)	1.88	1.69	0.00	0.00	0.94
Total Payment	(q) = (o) + (p)	8.12	7.93	6.24	10.00	10.94

CCP Factors with Two Transmission Constraints

Table A-21 through Table A-23 provide an illustrative example in which flows on the interface between an export zone and an import zone are limited by more than one constrained facility. It uses the same assumptions as the example with one line shown in Table A-18, but includes a second line (Line 2) with a limit of 135 MW. Each generator's GSF on Line 2 is not necessarily the same as its GSF on Line 1. To determine the interface limit from the export zone to the import zone, each generator's output level is adjusted to maximize output in the export zone while maintaining the load balance and respecting the limits of *both* Line 1 and Line 2. In this example, the optimal export limit of 230.2 MW occurs when both lines are constrained.

Compared to the example with one line, fewer units have positive CCP Factors. This is because additional capacity at a generator's location will not improve the interface limit unless the generator has a low GSF on *both* constraints. For example, raising output at the location of Unit A would allow for less loading on Line 1 (which resulted in a positive CCP Factor in the example with one line), but cause additional loading on Line 2, so it will not allow more total generation in the export zone. Unit B has a GSF below the 'marginal' GSF on both constraints, so it has a positive GSF and received a CCP Credit which increases its capacity payment.

Table A-21: Line and Unit Characteristics in Two Line CCP Factor Example

Line Limits	
Line 1 Limit (MW)	45
Line 2 Limit (MW)	135

Unit Characteristics and Output Levels

Unit		A	B	C	D	E	Load	Total
Net Gen Capacity (MW)	(a)	100.0	100.0	50.0	100.0	100.0	-400.0	50.0
GSF on Line 1	(b)	0.10	0.12	0.30	-0.10	-0.20	-0.10	
GSF on Line 2	(c)	0.32	0.25	0.30	-0.30	-0.30	-0.30	
Zone	(d)	Export	Export	Export	Import	Import	Import	
Output Scalar	(e)	0.95	1.00	0.70	0.70	1.00	1.00	
Scaled Net Gen (MW)	(f) = (a) * (e)	95.3	100.0	34.8	69.8	100.0	-400.0	0.0
Impact on Line 1 (MW)	(g) = (b) * (f)	9.5	12.0	10.5	-7.0	-20.0	40.0	**45.0**
Impact on Line 2 (MW)	(h) = (c) * (f)	30.5	25.0	10.5	-21.0	-30.0	120.0	**135.0**

Table A-22: Calculation of Capacity Prices in Two Line CCP Factor Example

Calculation of Zonal Prices

Export Zone Limit (MW)	(i) = Sum of (f) in export zone	230.2
Export Zone Supply (MW)	(j) = Sum of (a) in export zone	250.0
Export Zone Surplus	(k) = (j) / (i) - 1	8.6%
Export Demand Curve Length	(l)	20%
Import Zone Price ($/kW-mo)	(m)	10.00
Export Zone Price ($/kW-mo)	(n) = (m) * (1 - (k) / (l))	5.69
Constraint Shadow Price	(o) = (m) - (n)	4.31

Table A-23: CCP Factors in Two Line CCP Factor Example

CCP Factors and Credit/Charge		A	B	C	D	E
CCP Factor	(p)	0.00	0.11	0.00	0.00	0.02
Zonal Capacity Price	(q) = (m) or (n)	5.69	5.69	5.69	10.00	10.00
CCP Credit	(r) = (o) * (p)	0.00	0.47	0.00	0.00	0.09
Total Payment	(s) = (q) + (r)	5.69	6.16	5.69	10.00	10.09

This proposal has two primary advantages. First, it differentiates payments of resources based on their ability to improve deliverability across constrained transmission interfaces. This will improve the efficiency of capacity market signals for motivating resources to enter at the most valuable locations and avoid less-valuable locations. Second, the use of CCP Factors reduces the risk that a resource will receive inefficient capacity payments due to being grouped into a capacity zone to which it does not fully belong. For example, a resource that is located in an export zone but has a very low GSF on the constraint that determines that zone's export interface limit would be compensated under this proposal at a price similar to resources in the import zone. A resource could incur a CCP Charge (a negative adjustment to its capacity payment) if it is defined as belonging to an import zone but contributed to increased loading on a constrained interface into that zone.

The CCP Charge/Credit for generators that decrease/increase transfer capability that affects resource adequacy assessment is a particular type of Financial Capacity Transfer Right ("FCTR"). FCTRs can also be used to compensate merchant transmission investors that construct facilities that increase transfer capability that improves resource adequacy. FCTRs are discussed further in the next subsection.

H. Financial Capacity Transfer Rights for Transmission Projects

Investment in transmission can significantly reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. Recognizing these reliability benefits of transmission projects and providing them access to capacity market revenues could provide substantial incentives to invest in transmission. In this subsection, we discuss the reliability value of transmission projects and the potential for financial capacity transfer rights ("FCTRs") in providing investment signals for merchant transmission projects.[335]

Figure A-113: Breakdown of Revenues for Generation and Transmission Projects

Figure A-113 compares the breakdown of capacity and energy revenues for two hypothetical new generators (Frame CT and a CC) in Zone G with the revenue breakdown for the Marcy-South Series Compensation ("MSSC") project completed in 2016. The figure also compares the net revenues for these projects against their gross CONE and highlights the reduction in shortfall of revenues due to the proposed FCTRs. The ability to earn capacity revenues would have greatly improved the economic viability of the MSSC project, potentially rendering it competitive with generation solutions to providing reliability downstate. The information presented in the figure is based on the following assumptions and inputs:

- The MSSC project is assumed to increase UPNY-SENY transfer capability by 287 MW.[336]
- The system is assumed to be at the long-term equilibrium that is modeled in the demand curve reset process, with each locality at its Excess Level. GE-MARS simulations of the 2019 IRM topology indicate that the estimated reliability benefit (reduction in LOLE) from increasing the transfer capability of the UPNY-SENY interface by 50 MW is 0.0009 events per year.
- The FCTR revenues for the transmission project equal the product of the following three inputs:
  - The effect on the transfer limit of one or more interfaces (only UPNY-SENY in the case of the TOTS projects) from adding the new facility to the as-found system, and
  - The MRI of the increasing the transfer limit of UNPY-SENY, and
  - The value of reliability in dollars per unit of LOLE. Based on the results of the GE-MARS runs for the 2019 IRM topology, this value is assumed to be $2.65 million per 0.001 events change in LOLE.[337]

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335 See Recommendation 2012-1c in Section I.

336 Although the MSSC project increased the limit for the Central-East interface, GE-MARS simulations using the 2019 IRM topology indicated that the MRI for this interface is zero. Our assumption for increase in UPNY-SENY transfer capability is based on the following filing.

We estimated the Gross CONE for the TOTS projects using the following inputs:

a) Carrying charge of 9.2 percent based on the WACC developed in the 2016 demand curve reset study, a 40 year project life and 15 years MACRS depreciation schedule.

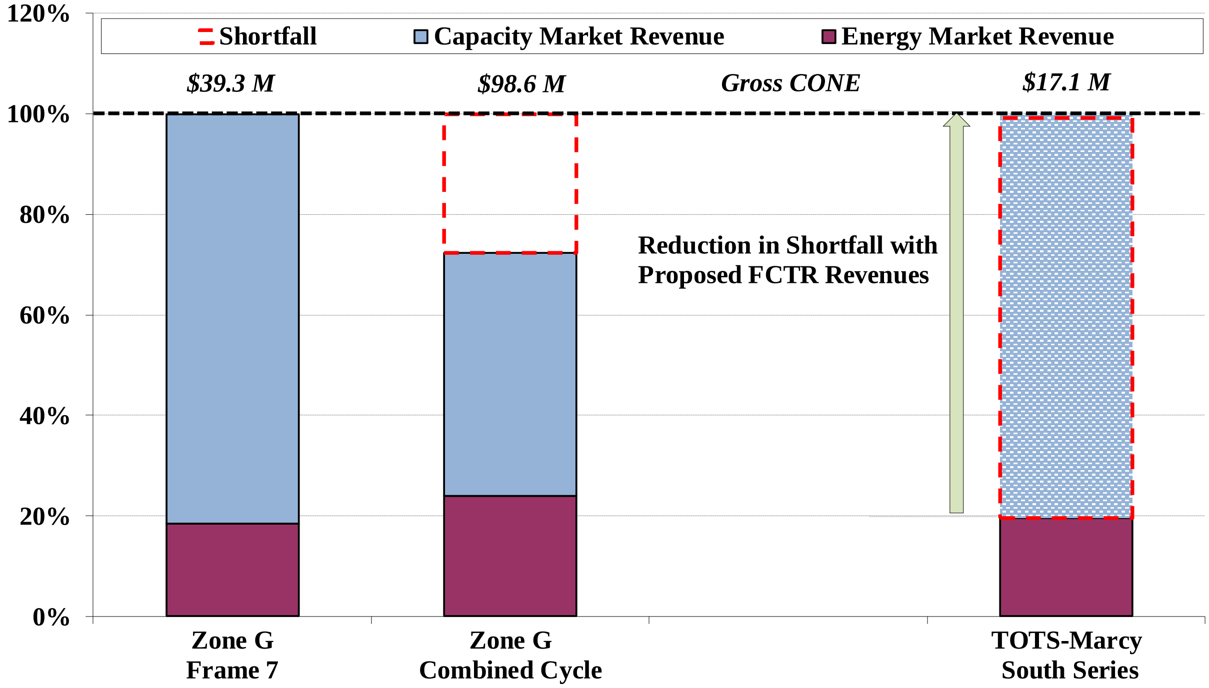
b) An investment cost of $120 million for the MSSC project (see here), inflated to 2019$.

c) An additional annual charge of 5 percent of investment costs to account for O&M and other taxes, based on the share of these costs reported in the New York Transco's Annual Projection dated 09/30/2017 for the TOTS projects.

337 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

- The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the MSSC project. Consistent with the 2019/20 Demand Curve annual update, the TCCs were valued based on the energy prices during September 2015 through August 2018.
- The gross CONE, energy and capacity market revenues for the Zone G Frame and CC units are based on the 2019/20 annual Demand Curve update.

Figure A-113: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



I. Winter-Summer Ratio Issue that Could Lead to Extreme Market Outcomes

The current seasonal market framework requires NYISO to make assumptions about the difference in the amounts of ICAP sold in summer and winter. This assumption (the Winter Summer Ratio, or "WSR") has a large impact on the value of the demand curve reference point prices. If the WSR is biased or inaccurate, the reference points will not be set at levels that produce revenues equal to the Net CONE when summer surplus is equal to the tariff-prescribed level of excess (LOE). In the past, the WSR was primarily driven by predictable differences in generators' seasonal capability. In the coming years, UDR resources (particularly the planned Champlain Hudson Power Express (CHPE) project) will likely change the relative availability of summer and winter capacity in the localities. There is a risk that seasonal variation in sales by UDRs will result in an inaccurate WSR and extreme pricing outcomes under current rules.

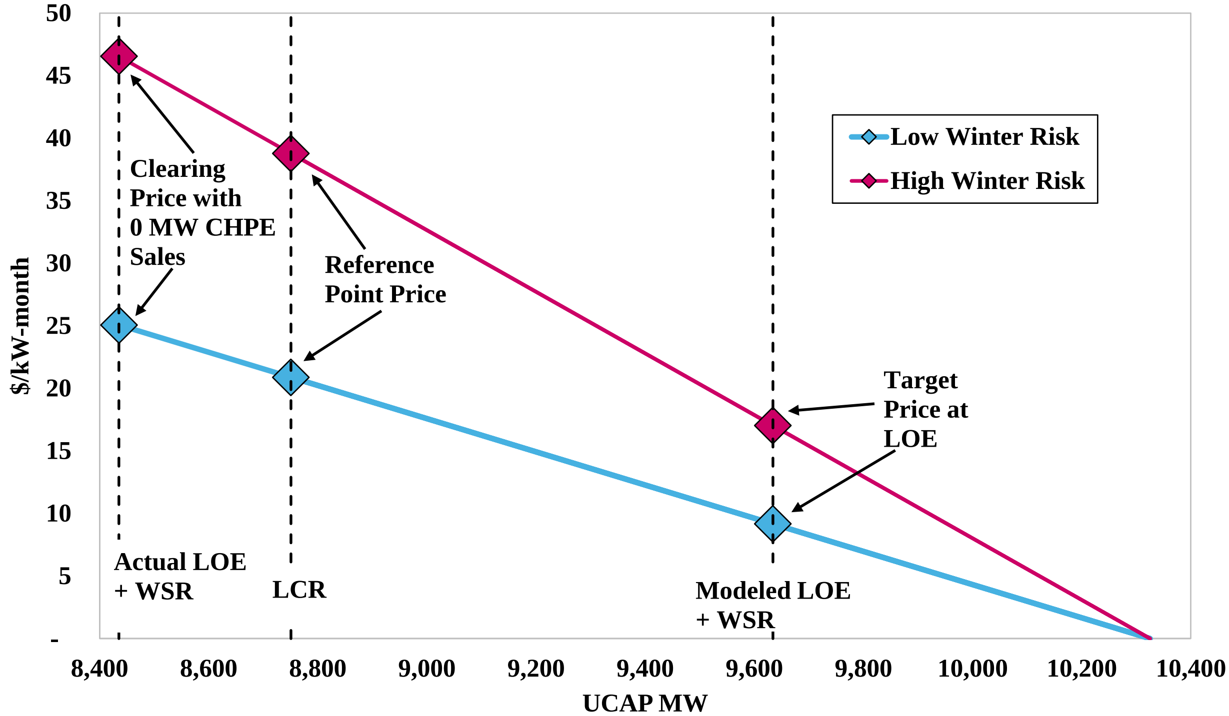
Many thermal generators have higher capability in winter than in summer. Hence, since the ICAP requirements are the same in all months, there is typically more surplus ICAP in winter than in summer. When the NYISO sets the demand curve reference points, it takes into account that the auction will clear further down the demand curve in winter than in summer. The WSR parameter is used to set reference points that will result in the reference unit earning its Net

CONE when summer capacity is equal to the requirement plus the tariff-prescribed level of excess, and winter capacity includes the additional surplus available in winter.

The WSR is calculated as the average amount of available ICAP participating in the winter capacity auction relative to the summer capacity auction over a historical three-year period.[338] The calculation of the WSR does not account for unsold capacity by resources that are available to participate in the auction. As a result, UDRs are assumed to provide the same amount of capacity in all months of the year, based on annual elections that the owners of the UDR make as part of the IRM process. However, UDRs may not necessarily sell capacity in all months of the year. Hence, if UDR sales are lower in winter than in summer, the WSR calculation will assume a larger amount of winter surplus capacity than is actually sold.

Figure A-114 shows estimated winter demand curves for New York City with CHPE in service, using 2024/25 parameters and NYISO's seasonal reference point calculation.[339]

Figure A-114: Recommended 2-Part Capacity Pricing when an LCR Is Based on the TSL



For the analysis shown in Figure A-114, we estimated demand curves assuming either a low level of winter risk in the LCR Study (so that the targeted winter revenue is at the floor of 35 percent of Net CONE) or a high level of winter risk (so that the targeted winter revenue is equal to 65 percent of Net CONE). The WSR is calculated assuming that CHPE elects to sell 1,250

338 The procedures for calculating the winter-to-summer ratio are defined by NYISO's tariff (MST Section 5.14.1.2.2.3). Annual calculations of the WSR can be found on NYISO's ICAP Market webpage under "Demand Curve Reset Annual Updates).

339 The risk highlighted in this subsection would be present in the absence of NYISO's recently filed seasonal reference point proposal, because the historic process for setting reference points also relies on the WSR.

MW of capacity as a UDR. The reference point is determined so that the price is equal to the target level when supply is equal to the LOE plus additional winter capacity assumed by the WSR. In this example, CHPE actually sells 0 MW of ICAP in winter. Hence, the actual amount of capacity sold in winter is lower than the amount assumed in the WSR calculation.

Importantly, the extreme prices in Figure A-114 do not imply that there is elevated winter reliability risk if CHPE fails to sell capacity in winter. Instead, the inflated winter price is an artifact of the WSR calculation (which considers seasonal ICAP levels, not risk or available capacity) rather than reliability issues.

Hence, we recommend that NYISO update its market processes to mitigate the risk of extreme pricing outcomes caused by inaccuracies in the WSR (Recommendation 2023-5). Potential solutions for the treatment of UDRs could include a requirement for UDR owners to make separate seasonal elections for summer and winter in the IRM study process, and/or changes to the calculation of the WSR parameter to account for unsold capacity. In addition, the WSR calculation should account for changes to the resource mix (such as known entry or retirements) rather than rely on a backward-looking calculation. Finally, corresponding modifications to the seasonal reference point formula may be required to ensure appropriate prices if the WSR value is less than one. We recommend making these improvements on an expedited basis to address the near-term risk of WSR distortions caused by UDRs. In the long term, our recommendation to adopt a seasonal capacity market discussed earlier in this section would eliminate the need for the WSR parameter entirely.

J. Analysis of NYISO's Deliverability Test Methodology

Section IV of this report critiques the deliverability study methodology used in NYISO's Class Year process and other interconnection studies to examine whether new resources are deliverable under the Deliverability Interconnection Standard (DIS). The DIS was designed to ensure that new resources will be deliverable throughout their capacity zone. However, the deliverability framework uses a test methodology that is poorly aligned with the resource adequacy analyses that are the primary basis for determining reliability needs and capacity prices in each region. As participation of renewables and storage grows, the methodology will tend to estimate resources' deliverability inaccurately during tight hours when capacity is most valuable. Consequently, the deliverability framework may identify and allocate excessively large SDUs to project developers. We discuss these concerns in this subsection.

Overview of the Highways and Byways Test

NYISO evaluates new resources' deliverability using a prescriptive methodology defined in the OATT.[340] The "highway/byway" analysis is the primary test resulting in SDUs, and it is

340 See OATT Section 25.7.8. NYCA Deliverability is defined as: "The NYCA transmission system shall be able to deliver the aggregate of NYCA capacity resources to the aggregate of the NYCA load under summer peak load conditions. This is accomplished, in the Class Year Study, through ensuring the deliverability of each Class Year CRIS Project, in the Capacity Region where the Project interconnects."

designed to examine whether all resources within a capacity zone are deliverable throughout that zone under a deterministic set of conditions.[341] It uses the following general procedure:

- The capacity zone is divided into several distinct subzones based on the location of relevant transmission bottlenecks.[342]
- A base case power flow simulation is developed in which total generation in the capacity zone is brought in balance with summer peak load.[343]
- For each subzone, generation in that subzone is increased while generation outside of the subzone is decreased, preserving the balance of generation and load. If this causes a transmission constraint to be violated before all generation in the subzone can reach its maximum level, resources in that zone are considered to be not deliverable.

The highway/byway test is deterministic and models a specific set of conditions representing summer peak load. The model includes all existing resources, new resources requesting CRIS in the Class Year, and proposed resources that obtained CRIS in a prior Class Year. Each resource is modeled with a maximum output level equal to its CRIS MW multiplied by one minus its UCAP Derating Factor (UCDF).

The UCDF is intended to reflect the resource's expected unavailability during summer peak conditions and may differ from its UCAP value used in the capacity market. For dispatchable resources (including energy storage), the UCDF is equal to the average EFORd in the capacity zone. For intermittent resources, it is based on the average output of that resource type during summer afternoon hours. NYISO has recently proposed changes to the calculation of the UCDF for intermittent resources as discussed further below.

The Deliverability Test is Inconsistent with Resource Adequacy and Reality

The deterministic highway/byway test does not represent a realistic or likely dispatch of the system. In fact, when a capacity zone has substantial excess capacity, raising the output to the maximum in one subregion and lowering it in others can produce dispatch conditions that would never be observed in actual operations. Consequently, this test is likely to identify required SDUs to mitigate identified constraints that may never bind in actual operations. This problem is exacerbated by performing the test in relatively large zones with many intrazonal constraints. Hence, defining more disaggregated capacity zones would greatly mitigate the concern.

In stark contrast to the deliverability test, resource adequacy requirements are assessed using a probabilistic framework intended to reflect reality and model conditions that are most likely to lead to capacity and energy shortages. Increasingly, these conditions may not correspond to the deterministic conditions modeled in the deliverability study. Hence, the deliverability test may

341 The SDU Study process also includes the interface transfer capability "No Harm" assessment, not discussed in detail here because it has not led to identification of SDUs in recent Class Year studies.

342 These subzones may correspond to individual NYISO load zones within the same capacity zone, or to local areas within one load zone.

343 This is done by scaling all capacity in the zone proportionally to its modeled maximum output level, until total generation is equal to peak load (plus load forecast uncertainty) net of imports from other areas.

fail to accurately reflect whether resources are deliverable at the times when they are most needed for resource adequacy. If resources are highly likely to be deliverable during the hours of greatest reliability need, it is inefficient to prevent them from entering and selling capacity or to compel them to incur large SDUs for constraints that would be unlikely to bind in these hours.

Concerns with the Current Deliverability Test for Renewables and Storage

Participation in the Class Year has heavily shifted towards renewables and storage in recent years. Unfortunately, NYISO's deterministic deliverability test tends to overestimate transmission impacts of these resources:

- *The deliverability test overestimates the output of intermittent resources.* It assumes they always produce at their UCDF-derated maximum output. The timing of reliability needs is increasingly likely to coincide with hours when renewable output is low. Since the deliverability test does not account for this, it will overestimate renewable output in hours when capacity is needed and underestimate transmission headroom in those hours.
- *Deliverability test ignores the complementary nature of storage and intermittent renewables*. Storage can support reliability by operating in hours when renewable output is low, but the deliverability test assumes all resources operate simultaneously.
- *Over-assignment of SDUs will grow as energy storage penetration rises*. As storage penetration increases, batteries may be able to support reliability in some cases by operating at a lower output level for more hours. The deliverability test assumes they operate at their maximum output level (derated by a UCDF reflecting forced outage risk).

Hence, the deliverability test is likely to overestimate the need for SDUs as renewable and storage capacity grow. These technologies make up the vast majority of projects in NYISO's interconnection queue. The preliminary SDU assigned to five solar projects in the Thousand Island region of Zone E in CY21 illustrate this concern:

- Of the projects' 564 MW of requested CRIS, 252 MW was found to be deliverable. This implies that 120 MW of UCAP can be simultaneously delivered based on the assumed summer peak solar capacity factor of 47.6 percent.
- By contrast, NYISO recently estimated that the marginal capacity value of solar resources in Zones A-F is 16.7 percent in 2023, meaning that solar resources are expected to have a capacity factor of 16.7 percent on average in hours when additional capacity would improve reliability.[344]
- Hence, the 252 MW of solar CRIS found to be deliverable would have an expected output of only 42 MW (252 MW times 16.7 percent) in tight hours, well below the 120 MW that can be simultaneously delivered.

344 NYISO has adopted changes to accredit capacity suppliers based on their marginal contribution to reliability, which largely reflects their expected availability during tight hours. See Section VIII.D. See NYISO presentation to ICAPWG on November 21, 2022 "Capacity Accreditation", available here.

NYISO recently adopted changes to the calculation of the UCDF for future Class Year studies (the "updated UCDF procedure").[345] Under the new approach, an intermittent resource's assumed output level will reflect its hourly summer capacity factor weighted by the load shedding risk in each hour of day in the latest GE-MARS IRM case.[346] This will help align the modeling of resources that have a consistent output pattern by time of day – such as solar – with the timing of reliability needs. However, it will continue to inaccurately estimate deliverability when resources' output varies in the same hour on different days (for example, a resource with a late afternoon capacity factor of 80 percent on one day and 10 percent the next day). The following analysis highlights inefficiencies that will remain under the updated UCDF procedure.

Analysis of the Deliverability Test Methodology with Updated UCDF Procedure

Recent Class Year studies have identified large SDUs needed for new wind and storage projects in Long Island, including over $900 million in the preliminary CY21 SDU Study. Figure A-115 and Figure A-116 below illustrate how the deterministic methodology used in the deliverability study will overestimate the transmission headroom needed to make wind and storage on Long Island deliverable during tight hours, compared to the type of probabilistic methods used to project intermittent resource availability in resource adequacy planning analyses. The "updated UCDF procedure" has been developed to address differences between the deliverability test assumptions and probabilistic approaches used in resource adequacy analyses, but the following analyses show that significant differences will remain.

Figure A-115 shows a duration curve of Long Island offshore wind output.[347] The curve shows the wind capacity factor in each hour ending 11 through 18 in June through August, arranged from highest to lowest.[348] The black horizontal line shows the assumed wind output calculated using the updated UCDF procedure. The hourly weights used to calculate the UCDF are derived from a resource adequacy simulation assuming all Long Island offshore wind projects in the CY21 and CY19 Class Year studies (3.1 GW of requested CRIS) are in service.[349] The red vertical lines mark the individual critical reliability hours in Long Island in the same simulation.[350]

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345 See discussion of "Translation Factors for IRM/LCR Studies and Deliverability Testing" in October 19, 2022 ICAPWG presentation "Capacity Accreditation" (available here) and draft ICAP Manual Attachment N published with December 14, 2022 Business Issues Committee meeting materials, available here.

346 For example, if a resource's average output in hours 17, 18 and 19 on summer days is 30%, 40% and 50% respectively, and the proportion of load shedding in hours 17, 18 and 19 in the IRM case is 10%, 20% and 70%, then the resource's UCDF will be {1 – (30% x 10% + 40% x 20% + 50% x 70%)} = 54%.

347 The offshore wind output profile shown is based on the assumptions used in NYISO's 2021 System & Resource Outlook study, which are derived from NREL offshore wind profiles.

348 All critical hours in the resource adequacy simulation described here took place in these hours.

349 New York's state climate law required 9 GW of offshore wind by 2035. The state has awarded contracts to 2.2 GW of offshore wind on Long Island to date, with another solicitation underway at the time of writing.

350 Critical hours are in the resource adequacy simulation are defined as hours in which load shedding occurs or hours in which storage resources were discharged prior to load shedding in the same day. The

Critical hours in Figure A-115 occur more frequently when offshore wind output is low because high offshore wind output results in a capacity surplus. As a result, the updated UCDF procedure significantly overstates offshore wind output during critical hours. Furthermore, over-estimating the transmission utilization by offshore wind will cause other projects to *appear* undeliverable even if they would be deliverable during the hours of greatest reliability risk. This is particularly problematic for energy storage projects, which would be very effective in generating more during periods of low offshore wind production.

Figure A-115: Long Island Offshore Wind Hourly Output and UCDF in Critical Hours

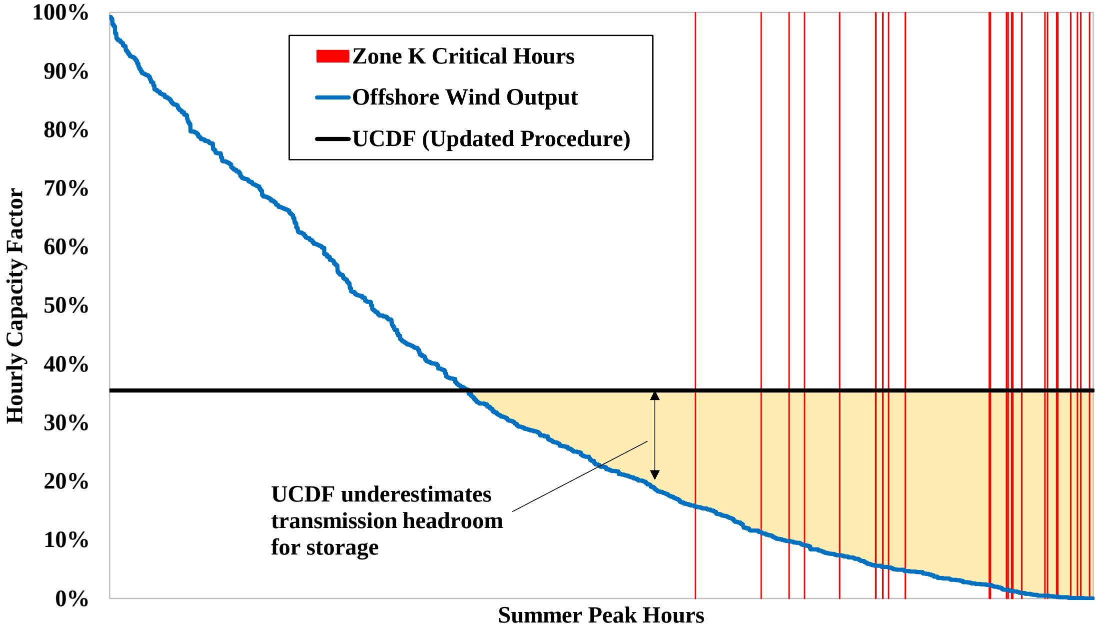

Figure A-116 estimates the amount of offshore wind and storage capacity in eastern and central Long Island made deliverable by a given amount of transmission headroom under (1) the deliverability study approach (using the updated UCDF procedure) and (2) a probabilistic approach that considers the marginal reliability impact (MRI) of resources upstream of a potential transmission bottleneck.[351] These amounts are compared to the requested CRIS of offshore wind and storage resources in eastern and central Long Island in the last two Class Year studies.[352] We estimate capacity made deliverable by a given increase in headroom as follows:

- Under the UCDF approach, we calculate the amount of offshore wind and storage installed capacity that would be made deliverable by a given increase in transmission

simulation assumes a system at the target level of reliability. It includes internal transfer limits between West, Central and East subzones in Long Island derived from the CY21 Preliminary SDU Study.

351 MRI quantifies the improvement in a reliability metric (such as loss of load expectation or expected unserved energy) provided by an incremental unit of a given type or location of capacity.

352 The deliverability test divides Long Island into West, Central and East subzones. Most offshore wind and storage resources in CY21 and CY19 intended to interconnect in Central and East Long Island and faced constraints from east to west. For the purposes of this test, we added wind and storage in fixed proportions consistent with the Class Year resources. We also included 1,356 MW of offshore wind requested CRIS in West Long Island that participated in CY21 in the resource adequacy simulation described in this section.

headroom, considering their assumed output under the updated UCDF procedure. Incremental headroom is assumed to be provided by retirements of existing resources.

- Under the MRI approach, we used an hourly resource adequacy simulation to determine the amount of offshore wind and storage in eastern and central Long Island that would provide comparable marginal reliability benefits to capacity in western Long Island, assuming a given increase in headroom is made available by retirements.[353]
- The yellow diamonds show the capacity value of the wind and storage in eastern/central Long Island that is deliverable under each approach. This is the amount of conventional UCAP in Long Island that can be removed in the resource adequacy simulation after adding the deliverable resources, while holding total unserved energy constant. [354]

Figure A-116 shows that retirements that create transmission headroom make a smaller amount of wind and storage capacity deliverable under the UCDF method than under a probabilistic MRI approach. This is because the UCDF method overestimates offshore wind output in critical hours and does not consider the complementarity between offshore wind and energy storage. The 2.3 GW of offshore wind and energy storage in eastern/central Long Island that participated in the last two Class Year studies would require 1,200 MW of transmission headroom under the UCDF approach, but they are made deliverable by just 600 MW of headroom under the MRI approach. Adjusting the UCDF values over time under the updated procedure will provide only a minor improvement in deliverability because of the misalignment of the hours used in the UCDF with the timing of critical hours shown in Figure A-115.

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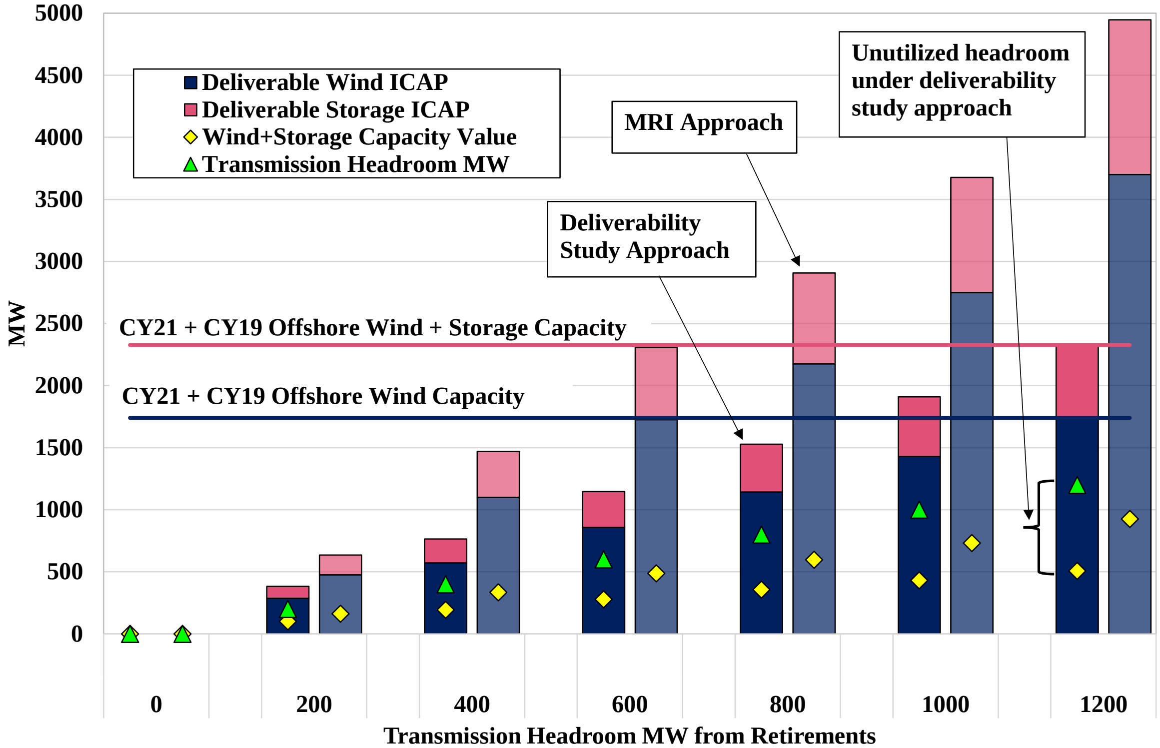
353 We use the following methodology to calculate deliverable MWs under the MRI approach:

First, the resource adequacy model is brought to a target level of reliability consistent with recent IRM studies. Transfer limits are modeled between NYISO capacity zones and between three subzones in Long Island (West, East and Central). Estimated transfer limits between Long Island subzones were based on the results of the CY21 Preliminary SDU Study. In the starting case at reliability criteria, capacity is removed such that available headroom for within-Long Island transfers is zero (e.g., all three subzones have similar MRI but additional capacity in Central or Eastern Long Island would cause the MRI of those zones to fall).

Next, ‘perfect capacity’ representing conventional generator UCAP is removed from central/eastern Long Island, corresponding to each level of headroom shown on the x-axis. Offshore wind and storage ICAP is then added to central/eastern Long Island, and additional perfect capacity is removed or added in Long Island so that the system returns to the target level of reliability. The largest amount of wind and storage capacity that can be added in this way while maintaining an MRI in each Long Island subzone equal to at least 90 percent of each other subzone is shown by the shaded bars.

354 We calculate the amount of conventional UCAP that can be displaced by the wind and storage resources as the headroom shown (represented in the resource adequacy model by a removal of perfect capacity in east and central Long Island), plus or minus additional perfect capacity that must be added or removed in Long Island so that the system remains at the target level of reliability. This is not equivalent to the marginal accredited value these resources would receive in the capacity market. It effectively represents the average capacity value of the resources added to eastern and central Long Island.

Figure A-116: Transmission Headroom from Potential Retirements for New Resources
Deliverability Study vs. MRI Approach – East/Central Long Island Example



This analysis also shows that a portfolio of offshore wind and storage resources requires more substantially more headroom under the UCDF approach (green triangles) than the capacity value it provides (yellow diamonds). For example, retirement of 1,200 MW of UCAP in eastern and central Long Island would provide deliverability headroom for 2.3 GW of offshore wind and solar ICAP, but these resources would provide capacity benefit equivalent to approximately just 500 MW of conventional UCAP. This implies that under the deliverability study approach: (1) if deliverability headroom is provided by construction of SDUs, the upgrades will be inefficiently oversized, or (2) if headroom is provided by retirement of existing resources, the new resources that can replace them will provide far less reliability value. By contrast, a probabilistic MRI-based approach more accurately indicates the amount of new resources that can make use of the headroom afforded by retirements.[355]

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355 This analysis should not be taken as a suggestion that simply using UCDFs derived from MRI results in the current deliverability test would yield accurate results. MRI results will not accurately reflect deliverability constraints unless the relevant transmission bottlenecks are represented in the underlying MARS case. Additionally, MRI results represent an expected improvement in reliability derived from many individual MARS iterations with different conditions, so they are not appropriate for use in a deterministic model. Our recommendations for improving the deliverability framework can be found at the end of this section.

VII. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the signals for investment in new generation and the retirement of existing generation. The decision to build or retire a generation unit depends on the expected net revenues the unit will receive. Net revenue is defined as the total revenue (including energy, ancillary services, and capacity revenues) that a generator would earn in the New York markets less its variable production costs.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions exist:

- New capacity is not needed because sufficient generation is already available;
- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- Market rules or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Therefore, the evaluation of the net revenues produced from the NYISO's markets is one of our principal means for assessing whether the markets are designed to provide efficient long-run economic signals.

In this section, we estimate the net revenues the markets would have provided to: (a) new and existing gas-fired units (subsection A), (b) existing nuclear plants (subsection B), (c) new utility-scale solar PV, land-based wind, and offshore wind units (subsection C), and (d) new battery storage (subsection D). Net revenues vary substantially by location, so we estimate the net revenues that each unit would have received at a number of locations across New York.

A. Gas-Fired and Dual Fuel Units Net Revenues

We estimate the net revenues from the market for four types of hypothetical gas-fired units:

- A new frame-type H-Class simple-cycle combustion turbine ("New CT") unit
- An existing Steam Turbine ("ST") unit
- An existing 10-minute Gas Turbine ("GT-10") unit, and
- An existing 30-minute Gas Turbine ("GT-30") unit.

We estimate the historical net energy and ancillary services revenues for gas-fired units in Long Island, the 345kV portion of New York City, the Hudson Valley Zone, and the West Zone. For energy and ancillary services revenues for units in the Capital Zone and West Zone, energy prices are based on average zonal LBMPs. For Long Island, results are shown for the Caithness CC1 generator bus, which is representative of most areas of Long Island, and for the Barrett 1 generator bus, which is representative of the Valley Stream load pocket. For New York City, results are shown for the Ravenswood GT3/4 generator bus, which is representative of most areas of the 345kV system in New York City.[356] For the Hudson Valley zone, results are shown for the average of LBMPs at the Roseton 1 and Bowline 1 generator buses, since these are representative of areas in the zone that are downstream of the UPNY-SENY interface. We also estimate historical capacity revenues based on spot capacity prices.

Table A-24 to Table A-26: Assumptions for Net Revenues of Fossil Fuel Units

Our net revenue estimates for gas-fired units are based on the following assumptions:

- All units are scheduled based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limits.
- ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while CTs may sell energy and 10-minute or 30-minute non-spinning reserves.
- CTs (including older gas turbines) are committed in real-time based on RTC prices.[357] CTs settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule. To the extent that these combustion turbines are committed uneconomically by RTC, they may receive DAMAP and/or Real-Time BPCG payments. Consistent with the NYISO tariffs, DAMAP payments are calculated hourly, while Real-Time BPCG payments are calculated over the operating day.
- Online units are dispatched in real-time consistent with the hourly real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, for the ST unit, a limitation on its ramp capability is assumed to keep the unit within a certain margin of the day-ahead schedule. The margin is assumed to be 25 percent of UOL.
- Generators in New York City, Long Island and Lower Hudson Valley are assumed to have dual-fuel capability. During hourly OFOs in New York City and Long Island, generators are assumed to offer in the day-ahead market as follows:

Table A-24: Day-ahead Fuel Assumptions During Hourly OFOs[358]

Technology	Gas-fired	Dual Fuel
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are included.
- The minimum generation level is 90 MW for the ST unit. At this level, its heat rate is 13,000 btu/kWh. The heat rate and capacity for a unit on a given day are assumed to vary

356 Prices at locations on the 345 kV network in New York city often differ from those on the lower-voltage 138 kV network, which typically experiences more localized congestion.

357 We assume a Frame unit is committed for an hour if the average LBMP in RTC at its node is greater than the applicable start-up and incremental energy cost of the unit for the full RTC look-ahead period of 2.5 hours, and an aeroderivative unit is committed for an hour if the average LBMP in RTC at its location is greater than the applicable start-up and incremental energy cost of the unit for one hour.

358 **Dual-fuel STs are assumed to offer Min Gen on the least expensive fuel and to offer incremental energy on residual oil in the DAM.

linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values and operating and cost assumptions are listed below.

- Fuel costs include a 6.9 percent natural gas excise tax for New York City units, a one percent gas excise tax for Long Island units, and transportation and other charges on top of the day-ahead index price as shown in the table below. Intraday gas purchases are assumed to be at a premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a discount for these reasons. The analysis assumes a premium/discount as shown in the table.

Table A-25: Gas and Oil Price Indices and Other Charges by Region[359]

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	Discount
West	April - November: Tennessee Zn 4 - 200 Leg December - March: Niagara	$0.27	$2.00	$1.50	10%
Capital	Iroquois Zn 2	$0.27	$2.00	$1.50	10%
Hudson Valley	Iroquois Zn2	$0.27	$1.50	$1.00	10%
New York City	Transco Zn6	$0.20	$1.50	$1.00	20%
Long Island	Iroquois Zn 2	$0.25	$1.50	$1.00	30%

- Existing GTs in NYC are modeled as not participating in the energy or capacity markets in the May through September ozone season, to reflect resource owners' compliance plans with NYSDEC Peaker Rule regulations.[360]

Table A-26: Gas-fired Unit Parameters for Net Revenue Estimates[361]

Characteristics	ST	GT-10	GT-30	New CT
Summer Capacity (MW)	360	32	16	358
Winter Capacity (MW)	360	40	20	370
Heat Rate (Btu/kWh)	10000	15000	17000	9300
Min Run Time (hrs)	24	1	1	1
Variable O&M (2024$/MWh)	$10.7	$5.4	$6.6	$1.5
Startup Cost (2024$)	$7,185	$1,436	$621	$28,228
Startup Cost (MMBTU)	3500	50	60	490
EFORd	5.14%	10.46%	19.73%	4.30%

359 The analysis assumes that the units in New York City region would switch from Transco Zn6 to Iroquois Zn2 when the Transco Zn6 pipeline is congested.

360 The Peaker Rule regulations first took effect in May 2023. The majority of affected capacity in New York City has indicated plans to either retire or cease operations during the ozone season. Although the Peaker Rule did not restrict revenues of these units in 2022, we show only non-ozone season revenues to reflect revenues under the future operating status of these facilities.

361 The parameters for the new CT are based on the recent NYISO ICAP Demand Curve reset study. See *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years – Final Report*.

- In 2024, New York State generators were in CSAPR Group 3, a cap-and-trade program requiring generators to obtain allowances for their NOx emissions during the Ozone Season. However, this allowance cost was partly offset by the provision that allowance allocations in future years will be partly based on 2024 emissions. To estimate the resulting net cost of NOx emissions in 2024, we derive the opportunity cost that would be implied if a ST emits a quantity equal to the average allowance allocation of generators in the same zone. For Hudson Valley ST units, the high NOx case corresponds to a unit with a higher level of historical allowances under the CSAPR program, while the low case corresponds to a unit with a lower level.
- All peaking units incur a $2.00/MWh cost when committed to provide operating reserves. This assumption is reflective of historical reserve market offers and is intended to represent costs incurred to make a generator available, secure fuel, and/or compensate for performance risks when providing reserves.

Figure A-117 to Figure A-119: Net Revenues Estimates for Fossil Fuel Units

The following three figures summarize our net revenue and run hour estimates for dual-fuel units in various locations across New York. They also indicate the levelized CONE estimated in the Demand Curve Reset for comparison. Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Net revenues from the sale of energy in the day-ahead market are shown separately for hours when the unit would operate on gas and hours when it would operate on fuel oil. Likewise, the additional net revenues that would be earned from the sale of day-ahead operating reserves and from participating in the balancing market are also separately for hours when the unit would operate on gas and hours when it would operate on fuel oil.

Figure A-117: Net Revenue & Cost for Fossil Units in West Zone and Hudson Valley
2022-2024

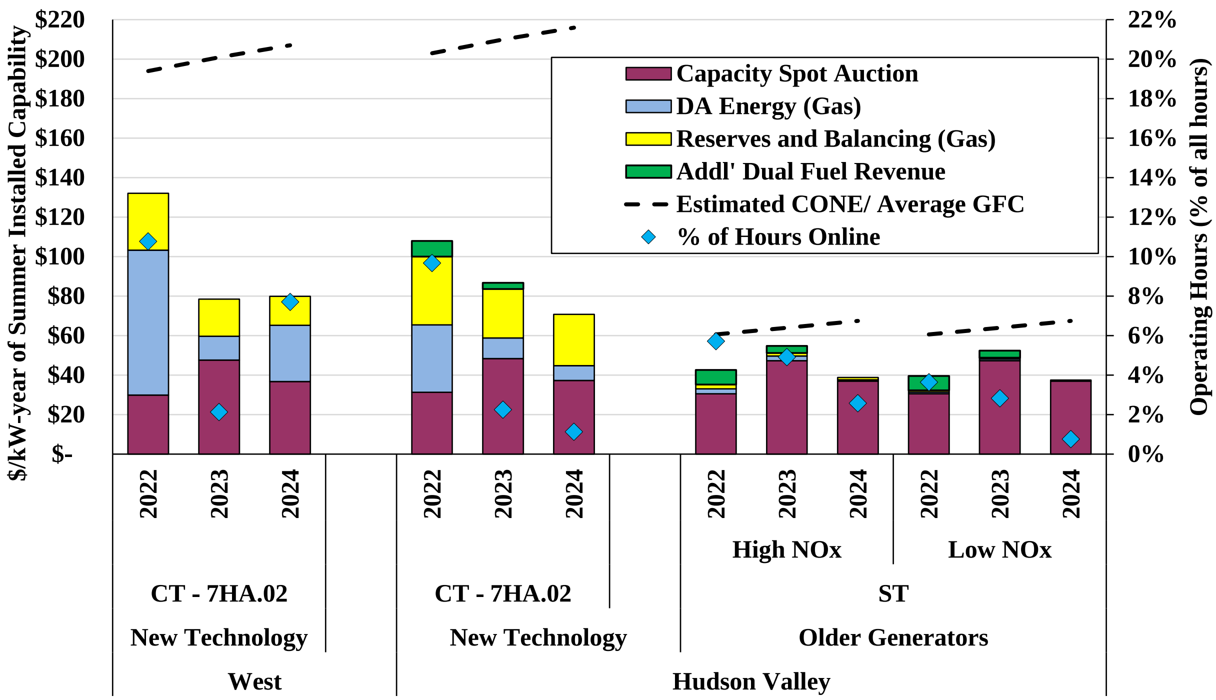


Figure A-118: Net Revenue & Cost for Fossil Units in New York City
2022-2024

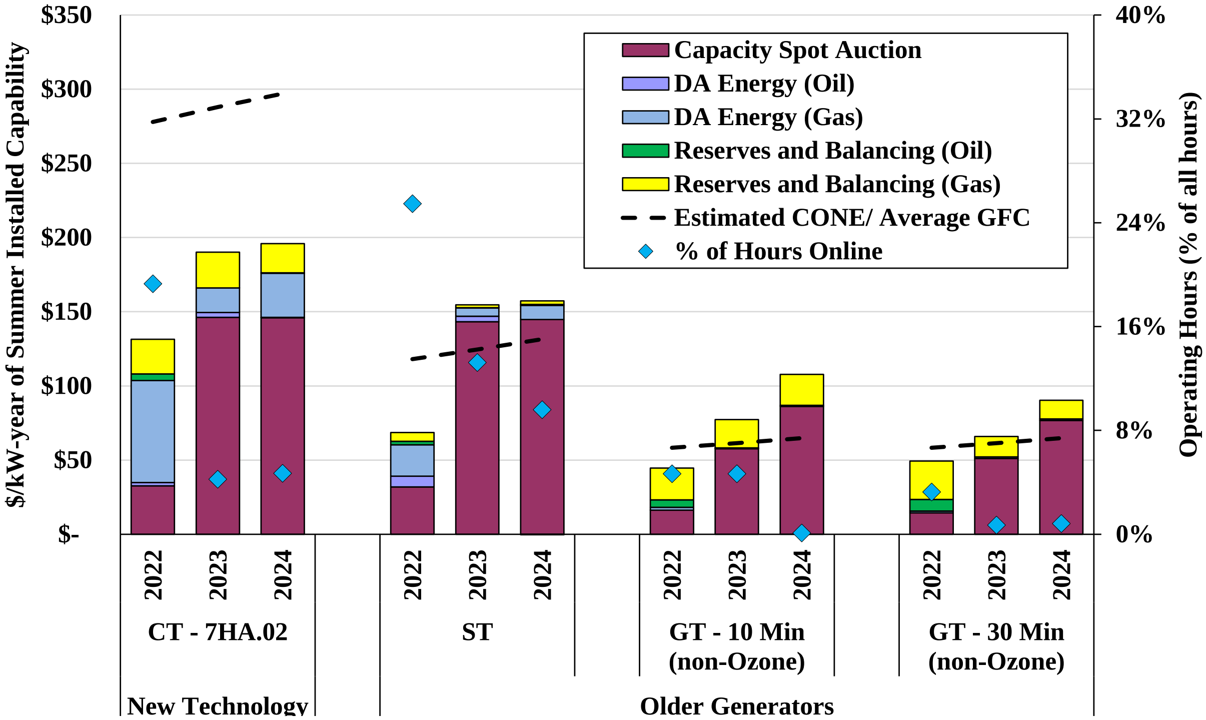
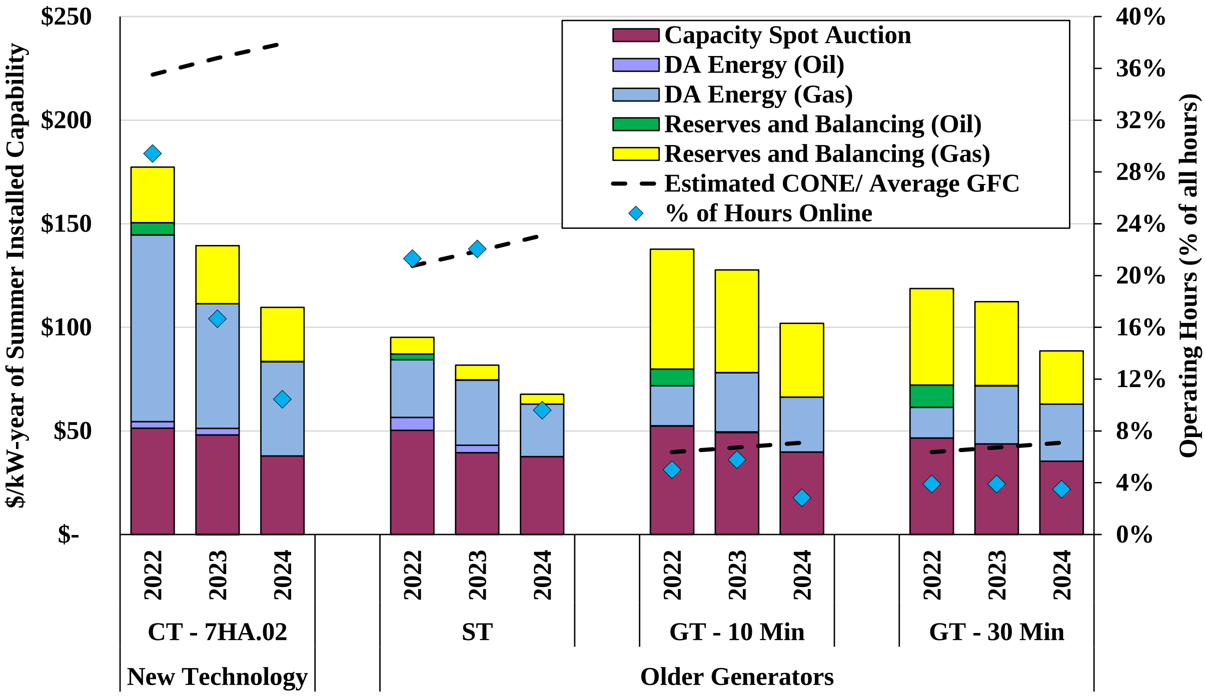


Figure A-119: Net Revenue & Cost for Fossil Units in Long Island
2022-2024



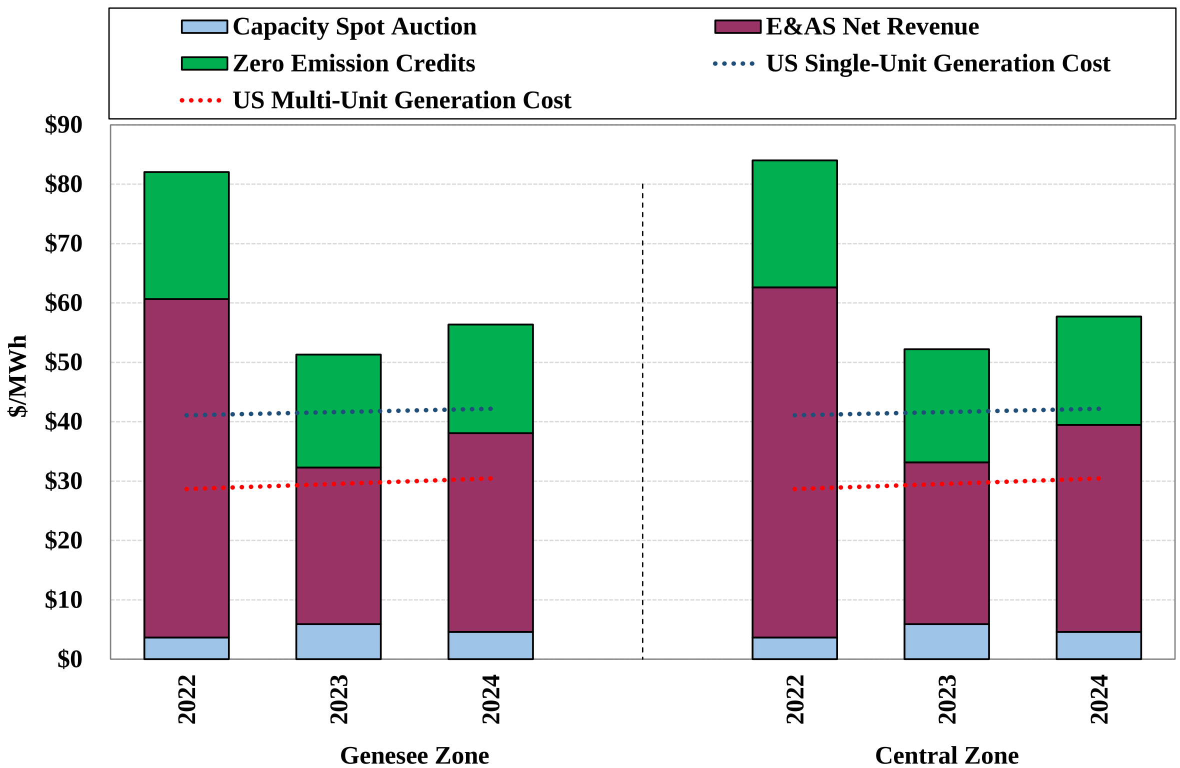
B. Nuclear Unit Net Revenues

We estimate the net revenues the markets provide to the nuclear plants in the Genesee and Central Zones. The estimates are based on LBMPs at the Ginna bus (for Genesee), and the Fitzpatrick and Nine Mile Unit 1 buses (for Central Zone).

Figure A-120: Net Revenues for Nuclear Plants

Figure A-120 shows the net revenues and the US-average operating costs for the nuclear units from 2022 to 2024. Estimated net revenues assume that nuclear plants are scheduled day-ahead and only sell energy and capacity. Nuclear units are assumed to earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two percent and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[362]

Figure A-120: Net Revenue of Existing Nuclear Units
2022-2024



The costs of generation (including O&M, fuel, and capex) for nuclear plants are highly plant-specific and vary significantly based on several factors that include number of units at the plant, technology, age, and location. Our assumptions for operating costs for single-unit and larger nuclear plants are based on observed average costs of nuclear plants in the US from 2022

362 The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year to enable a year over year comparison of net revenues.

through 2023.[363] The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[364] The ZEC price was $21.38/MWh for the period April 2021 to March 2023 and $18.27/MWh for the period April 2023 to March 2025.

C. Renewable Units Net Revenues

We estimate the net revenues the markets would have provided to utility-scale solar PV in the Central and Capital zones, land-based wind in the Central and North zones, and offshore wind plants interconnecting in Long Island and New York City. For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-27 and Figure A-121: Costs, Performance Parameters, and Net Revenues of Renewable Units

Table A-27 shows cost estimates for solar PV, land-based wind and offshore wind units we used for a unit that commence operations in 2024. Costs are based on NYISO's Renewable Technology Costs study and NREL's Annual Technology baseline (ATB).[365] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units.

Assuming the operating and cost parameters shown in Table A-27, Figure A-121 shows the net revenues and the estimated CONE for each of the units during years 2022-2024. The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and land-based wind units assumes net E&AS revenues are calculated using real time energy prices. Energy production is estimated using technology and location-specific hourly capacity factors. The capacity factors are based on location-specific resource availability and technology performance data.[366]

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363 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See here.

364 See State of New York PSC's "Order adopting a clean energy standard", issued on August 1, 2016 at page 130. The price of ZECs is determined by 1) starting with the U.S. government's estimate of the social cost of carbon; 2) subtracting fixed baseline portion of this cost already captured in current wholesale power prices through the forecast RGGI prices embedded in the CARIS phase 1 report; and 3) converting the value from $/ton to $/MWh, using a measure of the New York system's carbon emissions per MWh. These prices are subject to reduction by any increase in the Zone A forward capacity and energy prices above a threshold of $39/MWh. ZEC prices are fixed in advance for two year tranches and published by the NYDPS in Case 15-E-0302.

365 We used costs and capacity factors from NREL's ATB for Class 3 offshore wind cost and Class 10 solar. Capital costs also include an estimated interconnection cost based on average by technology in recent Class Year studies. Property tax payments for land-based wind and solar PV projects are estimated as 0.5% of capital cost.

366 Assumed yearly capacity factors for solar PV, land-based wind, and offshore wind units are sourced from the 2023 NREL ATB and operational data from NYISO resources.

Table A-27: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2024) (2024$/kW AC basis)	*Upstate NY*: $1,688	*Upstate NY*: $2,017	*NYC/Long Island* : $6,493
Fixed O&M (2024$/kW-yr)	$25	$37	$99
Federal Incentives	ITC	PTC	ITC
Project Life	30 years	20 years	25 years
Debt Term	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	20.0%	35.0%	45.0%
Unforced Capacity Percentage	Summer: 16% Winter: 14%	Summer: 13% Winter: 12%	Summer: 32% Winter: 32%
Renewable Energy Credits (Nominal $/MWh)	*Onshore Wind and Solar PV:* ***2024*** *- $33.98* ***2023*** *-* $29.36 ***2022*** *-* $20.67 *Offshore Wind:* Calculated using Offshore Wind Solicitation Index REC strike price of $150/MWh ($2026)		

The capacity revenues for solar PV, land-based wind, and offshore wind units are calculated using prices from the spot capacity market. Capacity values are based on the latest Capacity Accreditation Factors (CAFs) beginning in 2024.[367]

We estimated the value of Renewable Energy Credits ("RECs") produced by utility-scale solar PV and land-based wind units using annual Tier 1 REC sale prices published by NYSERDA.[368] Offshore REC ("OREC") prices were estimated using the average Index REC strike price of recently announced Offshore Wind procurement with expected commercial operation date in 2026, converted to dollars of the year shown.[369]

Solar PV, offshore wind, and land-based wind plants are eligible for the Investment Tax Credit ("ITC") or the Production Tax Credit ("PTC"), which are federal programs to encourage renewable generation. The ITC reduces the federal income tax of the investors by a portion of a unit's eligible investment costs depending on the resource type, and is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced

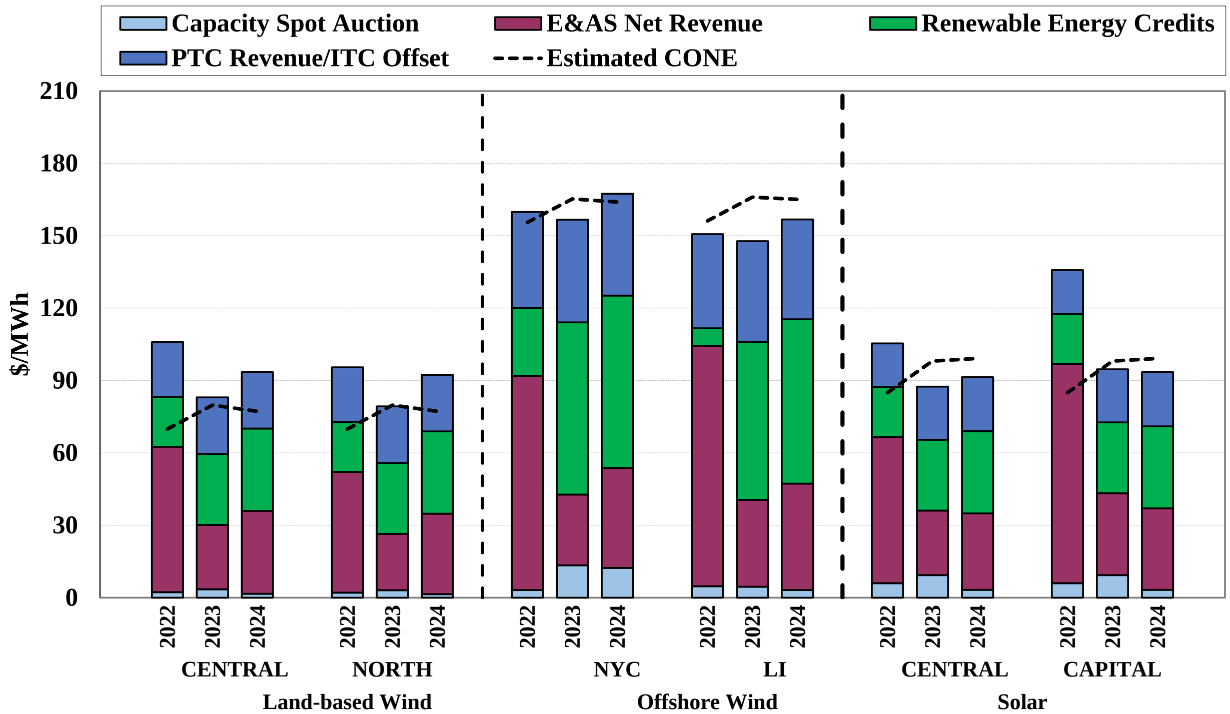
367 Capacity values before 2024 are defined in NYISO's ICAP Manual. Beginning in the 2024/25 capability year, capacity values in all months are determined by the new Capacity Accreditation process (see here).

368 For more information on the recent RES Tier 1 REC procurements, see here. The average Tier 1 REC sale price for LSEs to satisfy Renewable Energy Standard (RES) requirements by purchasing RECs from NYSERDA for the 2024 Compliance Year was $33.98/MWh.

369 See NYSERDA press release for 2023 Offshore Wind Solicitation, available here.

by a wind facility over a period of 10 years.[370] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[371]

Figure A-121: Net Revenues of Solar, Land-based Wind and Offshore Wind Units
2022-2024



Renewable generators are assumed to incur a lower cost of capital due to the availability of revenues from sale of renewable energy credits, which carry a lower risk relative to NYISO market revenues. Accordingly, we assumed a weighted average cost of capital reflecting a mix of merchant and regulated risk based on publicly available information about the cost of

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370 For solar PV, the ITC was 30 percent for projects that began construction in 2019 or earlier, with a safe harbor period up to four years. Consequently, for the timeframe of our analysis, we assumed 30 percent ITC for solar PV projects.

For offshore wind, the ITC is 30 percent of the eligible investment costs for projects that commence construction before 2026. The safe harbor period for the projects is up to ten years. Consequently, we assumed 30 percent ITC for offshore wind projects.

For land based wind, under the Inflation Reduction Act, projects that entered service in 2022 are eligible for the full PTC at 100 percent of the new rate of 2.6 cents per kWh. The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC.

371 In addition to these federal programs, renewable power projects may qualify for several other state or local-level incentives (e.g., property tax exemptions) in New York. However, our analysis does not consider any other renewables-specific revenue streams or cost offsets beyond the revenues from sale of Renewable Energy Credits and the PTC or the ITC.

financing for renewable projects.[372] Our estimated CONE for renewable generators assumes a 2 percent annual escalation of revenues after Year 1.

D. Energy Storage Revenues

We estimate the revenues the markets would have provided to energy storage resources in the NYC and Long Island zones. For each of these zones, we estimate the revenues from the NYISO markets and from state and federal incentive programs.

Figure A-122: Costs, Performance Parameters, and Net Revenues of Energy Storage Units

The assumed operating characteristics are as follows:

- We studied a grid-scale battery storage unit with a power rating of one MW and four hours or two hours of storage capacity. We assume a roundtrip efficiency of 85 percent.
- We model storage revenues assuming that the battery offers a portion of its capacity as 10-minute spin reserves in the day-ahead market, then self-schedules to charge or discharge in the real time market to take advantage of energy arbitrage and real-time reserve opportunities We assume that the battery operator lacks perfect foresight of real-time market prices. Instead, we develop threshold prices at which to charge or discharge using an algorithm that considers the day-ahead forecast, RTC forecast, and backward-looking prices from the week prior to each operating day. Figure A-122 assumes that 100 percent of the battery's capacity is offered as day-ahead reserves, which was the highest-revenue strategy in the period 2022-2024.
- Capacity credit for a four-hour storage resource is based on the final capacity accreditation factors (CAFs) for the 2024/25 capability year for 2024 and previous default values (90 percent for four-hour, 45 percent for two-hour) in prior years. The CAF for a four-hour battery is 68.8 percent in New York City and 78.9 percent in Long Island. The CAF for a two-hour battery is 55.9 percent in New York City and 52.8 percent in Long Island.
- Cost assumptions are based on NYISO's 2024 Demand Curve Reset study and 2024 NREL ATB. Assumed capital costs for a four-hour battery in 2024 are $3,380 per kW in NYC, $2,168 per kW in Long Island, and $2,036 per kW upstate. Assumed capital costs for a two-hour battery in 2024 are $2,094 per kW in NYC, $1,343 per kW in Long Island, and $1,261 per kW upstate. We assume a 20 year project life and merchant cost of capital with after-tax WACC of 9.6 percent in 2024.[373]

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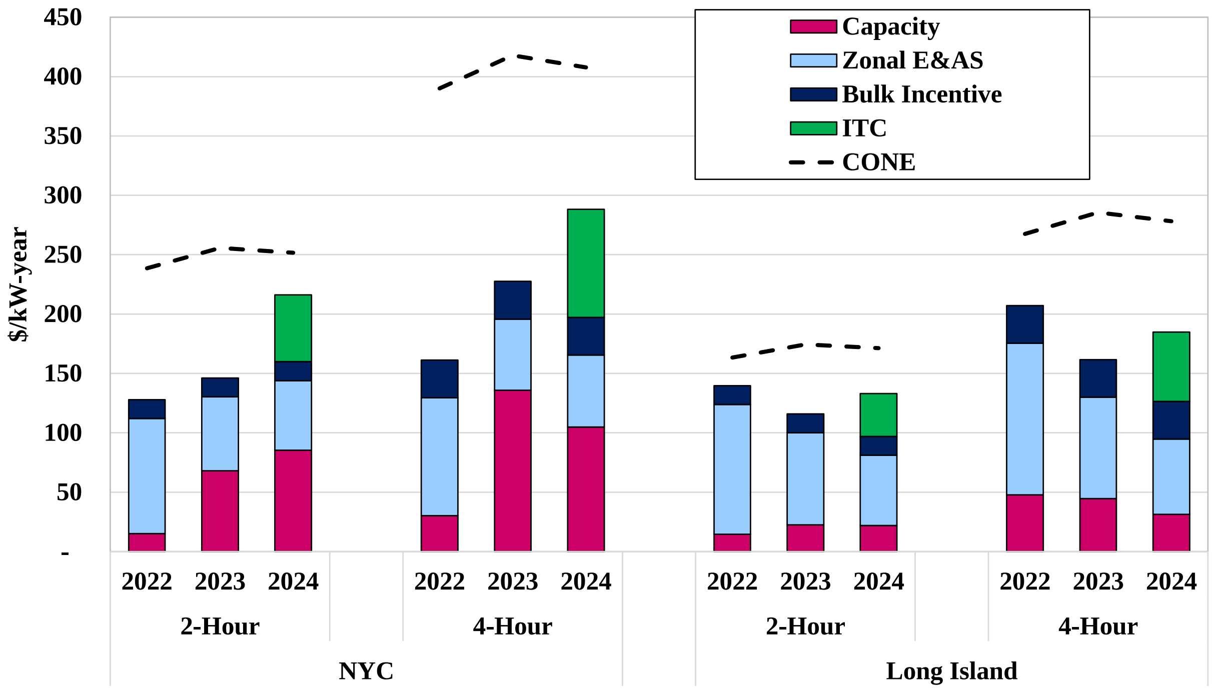
372 See Norton Rose Fulbright Cost of Capital: 2025 Outlook, available here. We estimated cost of capital in each year assuming a pre-tax cost of debt equal to the Secured Overnight Financing Rate (SOFR) plus indicated lender spreads, a debt to equity ratio targeting a debt service coverage ratio (DSCR) that reflects a combination of merchant and contractual revenues, and a cost of equity based on the NYISO's 2024 Demand Curve Reset. For 2024, we calculate an ATWACC of 8.6 percent for wind, 8.5 percent for solar, and 9.6 percent for merchant storage.

373 See description of our methodology for estimating cost of capital in Section C.

- Bulk storage resources are assumed to be eligible for the NYSERDA Bulk Storage Incentive program, at a rate of $75 per kWh of installed storage capacity.[374] We levelize this benefit over the course of the project's life using a merchant cost of capital.
- Standalone battery storage entering service through 2022 was not eligible for the federal Investment Tax Credit, but storage projects entering service beginning January 1, 2023 will quality for a 30 percent ITC. We show the impact that the ITC would have had on storage economics in Figure A-122.

Figure A-122 shows the net revenues and the estimated CONE for each of the units during years 2022-2024. The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.[375]

Figure A-122: Net Revenues and CONE of Energy Storage Units[376]
2022-2024



374 See here. Bulk projects in Con Edison service territory are eligible to compete for contracted payments from the utility instead of this bulk incentive; for this analysis we assume the incentives to resources in Zone J under this approach are comparable to the bulk storage incentive available elsewhere.

375 In addition to revenues from capacity, E&AS, and Bulk Incentive, we show theoretical revenues from the ITC, which is available starting in 2023.

376 Capacity revenues are shown for each calendar year.

VIII. DEMAND RESPONSE PROGRAMS

Demand response contributes to reliable system operations, long-term resource adequacy, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response.

NYISO currently operates five demand response programs that allow retail loads to participate in the wholesale market. Three of the five programs allow NYISO to curtail loads in real-time for reliability reasons:

- Emergency Demand Response Program ("EDRP") – These resources are paid the higher of $500/MWh or the real-time clearing price. There are no consequences for enrolled EDRP resources that fail to curtail.[377]
- Installed Capacity/Special Case Resource ("ICAP/SCR") Program – These resources are paid the higher of their strike price (which can be up to $500/MWh) or the real-time clearing price. These resources sell capacity in the capacity market in exchange for the obligation to respond when deployed.[378]
- Targeted Demand Response Program ("TDRP") – This program curtails EDRP and SCR resources when called by the local Transmission Owner for reliability reasons at the sub-load pocket level, currently only in New York City. EDRP resources are paid the higher of $500/MWh or the real-time clearing price. SCRs are paid the higher of their strike price or the real-time clearing price. Response from these resources is voluntary.

The other two are economic demand response programs that allow demand response resources to participate in the day-ahead energy market or in the ancillary services markets:

- Day-Ahead Demand Response Program ("DADRP") – This program allows curtailable loads to offer into the day-ahead market (subject to a floor price) like any supply resource.[379] If the offer clears in the day-ahead market, the resource is paid the day-ahead clearing price and must curtail its load in real-time accordingly. Failure to curtail may result in penalties being assessed in accordance with applicable rules.
- Demand Side Ancillary Services Program ("DSASP") – This program allows Demand Side Resources to offer their load curtailment capability to provide regulation and operating reserves in both day-ahead and real-time markets. DSASP resources that are

377 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

378 SCRs participate through Responsible Interface Parties ("RIPs"). Resources are obligated to curtail when called upon by NYISO to do so with two or more hours in-day notice, provided that the resource is informed on the previous day of the possibility of such a call.

379 The floor price was $75/MWh prior to November 2018. Since then it has been updated on a monthly basis to reflect the Monthly Net Benefits Floor per Order 745 compliance.

dispatched for energy in real-time are not paid for that energy. Instead, DSASP resources receive DAMAP to make up for any balancing differences.

Despite these programs, significant barriers to participation in the wholesale market by loads remain. The most significant barrier is that most retail loads have no incentive to respond to real-time prices even when they exceed their marginal value of consumption. Hence, it is important to develop programs to provide efficient incentives to demand response resources and facilitate their participation in the real-time market.

NYISO has been working on a series of market design projects that are intended to facilitate more active participation by consumers. These projects include:

- Meter Service Entity ("MSE") for DER – The MSE rules went into effect in May 2020, which authorize third party metering that provides greater flexibility to consumers and retail load serving entities for demand side participation.
- Dual Participation ("DP") – The DP rules went into effect in May 2020, which allow resources that provide wholesale market services to also provide retail market services.
- DER and Aggregation Participation Model – The NYISO implemented its DER and Aggregation participation model on April 16, 2024, allowing individual large consumers and aggregations of small consumers to participate more directly in the market. This model enables resources to better reflect duration limitations in their offers, payments, and obligations. As part of this transition, NYISO is phasing out DADRP and DSASP programs. Current DSASP and DADRP resources are required to either transition to the DER and Aggregation Participation model or withdraw from the market before the target sunset date of October 31, 2025.

This section evaluates the performance of the existing programs in 2024 in the following subsections: (a) reliability demand response programs, (b) economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions. No resources actively participated in the DER and Aggregation Participation Model in 2024. Future reports will examine its performance as participation increases.

A. Reliability Demand Response Programs

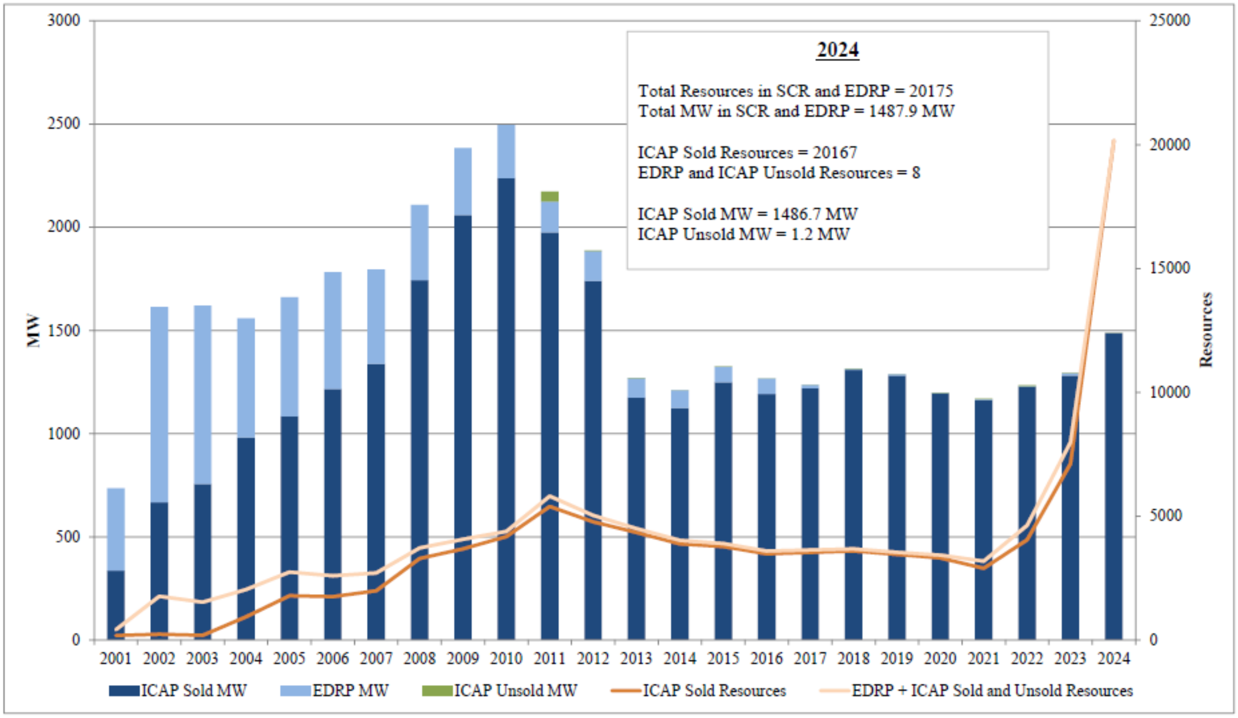
The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when the NYISO and/or a TO forecast a reliability issue.

Figure A-123: Registration in NYISO Demand Response Reliability Programs

Figure A-123 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2024 as reported in the NYISO's annual demand response report. The stacked bar chart plots enrolled ICAP MW by year for each program. The lines plot the number of end-use locations by year for each program. Since EDRP resources and SCRs in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

Over the past decade, SCRs have accounted for nearly all of the total enrolled MWs in the reliability-based programs because capacity market revenues account for most of the revenues available to emergency demand response resources. The Expanding Capacity Eligibility market rules became effective in May 2021 and began to discount the capacity payments to SCRs by the same amount as 4-hour duration limited resources. In May 2021, the Duration Adjustment Factor was 90 percent.[380] After the Capacity Accreditation rules went into effect, the Capacity Accreditation Factor of 4-hour duration limited resources and SCRs ranged between roughly 64 and 79 percent (depending on the Capacity Region) in the 2024/25 Capability Year and between 79 and 87 percent in the 2025/26 Capability Year.

Figure A-123: Registration in NYISO Demand Response Reliability Programs [381]
2001 – 2024



B. Economic Demand Response Programs

The NYISO offers two economic demand response programs.[382] First, the DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to

380 See Section 4.1.1 of ICAP Manual for more details.

381 This figure is excerpted from *NYISO 2024 Annual Report on Demand Response Programs*, February 28, 2024, available at: www.nyiso.com/demand-response under *"DR05 - NYISO Semi-Annual Demand Response Report - 2025."*

382 In addition, there is a Mandatory Hourly Pricing ("MHP") program administered at the retail load level, which is currently regulated under the New York Public Service Commission. This program encourages loads to respond to wholesale market prices, which intends to shift customer load to less expensive off-peak

generation supply offers, currently subject to the Monthly Net Benefit Offer Floor.[383] Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. Load reductions scheduled in the day-ahead market obligate the resource to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead and the real-time price of energy. DADRP enrollment has been static and no enrolled resources have submitted demand reduction offers since December 2010.

Second, the DSASP program allows demand response resources to provide ancillary services. This program has increased the supply of operating reserves, which enhances competition, reduces costs, and improves reliability. Under this program, resources must qualify to provide operating reserves or regulation under the same requirements as generators, and they are paid the same market clearing prices as generators for the ancillary service products they provide. To the extent that DSASP resources increase or decrease consumption when deployed for regulation or reserves in the real-time, they settle the energy consumption with their load serving entity rather than with the NYISO. But they are eligible for a Day-Ahead Margin Assurance Payment (“DAMAP”) to make up for any balancing differences between their day-ahead operating reserves or regulation service schedule and real-time dispatch, subject to their performance for the scheduled service. Currently, twelve DSASP resources actively participate in the market as providers of operating reserves. These resources collectively can provide up to 433 MW of operating reserves.

However, NYISO is phasing out the DADRP and DSASP programs with a target sunset date of October 31, 2025. Current DSASP and DADRP resources will have to either transition to the DER and Aggregation Participation Model or exit the market.

C. Demand Response and Scarcity Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under scarcity conditions. Ordinarily, to be involved with setting prices in the real-time market, resources must be dispatchable by the real-time market model on a five-minute basis. EDRP and SCR resources must be called in advance based on projections of operating conditions; they are not dispatchable by the real-time model. Hence, there is no guarantee that these resources will be “in-merit” relative to the real-time clearing price, and their deployment can lower prices. Prices can be very low after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time. NYISO currently has two market rules that improve the efficiency of real-time prices when demand response resources are deployed.

periods and reduce electric system peak demand. Under the MHP program, retail customers as small as 200 kW (depending on their load serving entity) pay for electric supply based on the day-ahead market LBMP in their load zone in each hour.

383 Prior to November 2018, DADRP Resource offers were subject to a static floor price of $75/MWh. The Monthly Net Benefit Offer Floor prices are available at: www.nyiso.com/demand-response

First, to minimize the price-effects of "out-of-merit" demand response resources, NYISO has the TDRP currently available in New York City. This program enables the local Transmission Owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. This prevents the local Transmission Owner from calling all the EDRP and SCR resources in New York City to address local issues and avoids deploying substantial quantities of demand response that provide no reliability benefit but unnecessarily depress real-time prices and increase uplift.

Second, NYISO has special scarcity pricing rules for periods when demand response resources are deployed. Generally, when a shortage of 30-minute reserves is prevented by the deployment of demand response in certain regions (e.g., state-wide, Eastern New York, or Southeastern New York), real-time energy prices will be set to $500/MWh or higher within the region. This rule helps reflect the cost of maintaining adequate reserve levels in real-time clearing prices and improves the efficiency of real-time prices during scarcity conditions. Prior to June 22, 2016, the real-time LBMPs during EDRP/SCR activations were set in an *ex-post* fashion, which tended to cause inconsistencies between resource schedules and pricing outcomes and result in potential uplift costs. NYISO implemented a Comprehensive Scarcity Pricing on June 22, 2016 to address this issue. Under this enhanced rule, the 30-minute reserve requirement in the applicable region is increased to reflect the expected EDRP/SCR deployment in the pricing logic, setting the LBMPs in the applicable region at a proper level in an *ex-ante* fashion.

Table A-28 - Figure A-124: Reliability Demand Response Deployments by NYISO

Table A-28 summarizes the reliability demand response events in 2024. The table lists for each event the program type (i.e., TDRP or SCR/EDRP), the start and end times, required zones, and obligated ICAP MWs. The table also indicates whether the scarcity pricing rule was triggered during the event and affected LBMPs in how many intervals.

Table A-28: Summary of Reliability Demand Response Activations
2024

DR Program	Event Date	Start Time	End Time	Event Zone	Obligated ICAP MW	# of RT Market Intervals w/ Scarcity Pricing Triggered
SCR/EDRP	6/20/2024	15:00	19:00	K	28	0
SCR/EDRP	7/15/2024	15:00	20:00	A-K	1429	12
SCR/EDRP	7/16/2024	15:00	20:00	A-K	1429	11
SCR/EDRP	8/1/2024	15:00	22:00	A-K	1434	20

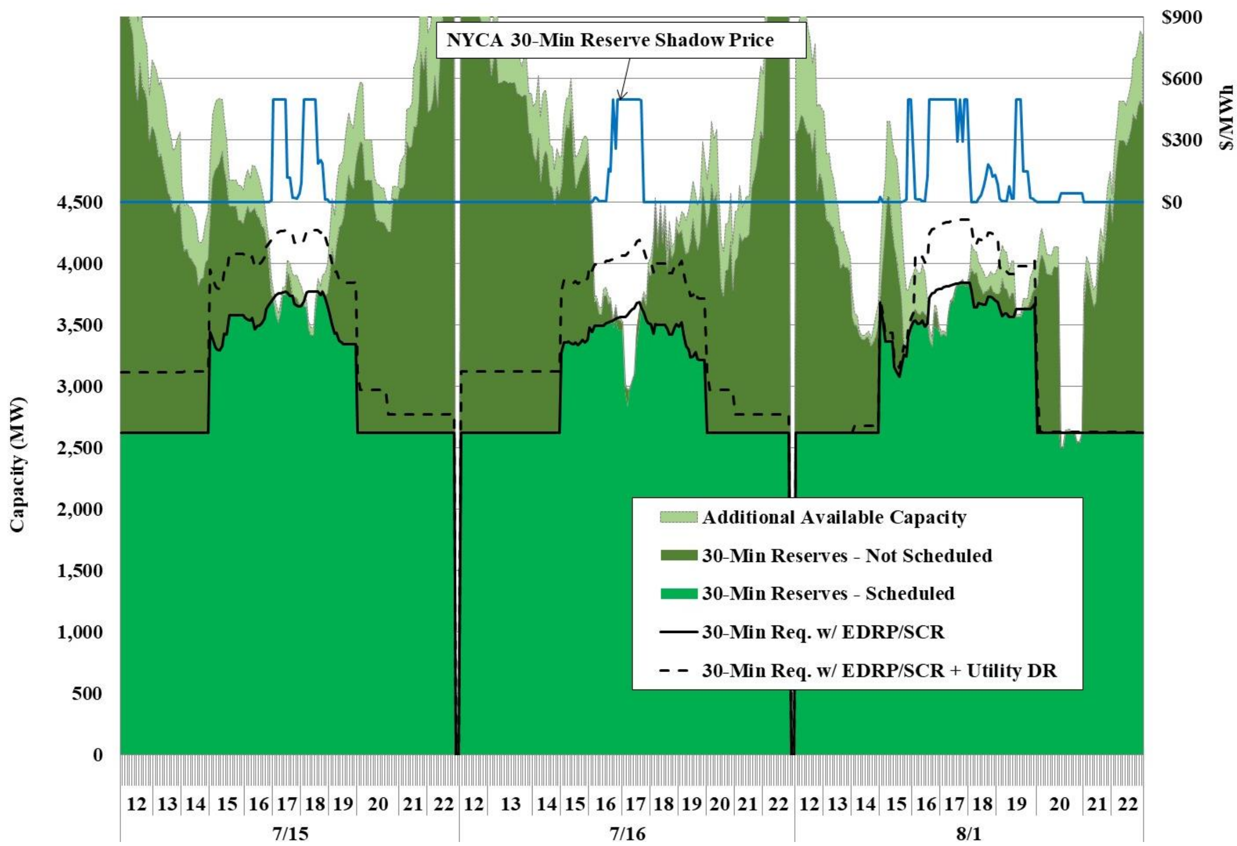
Figure A-124 summarizes market outcomes during three reliability demand response activations on July 15, 16, and August 1. The figure reports key market quantities at the 5-minute interval level for NYCA during the afternoon peak hours (HB 12 – HB 22), including:

- Available capacity – This includes three categories of unloaded capacity from online units and the capacity of offline peaking units up to their Upper Operating Limits:

  - o 30-minute reserves that are scheduled by the market model;
  - o 30-minute reserves that are available but are not scheduled by the market model; and
  - o Additional capacity that is only available beyond a 30-minute ramping window.
- Constraint shadow prices on the NYCA 30-minute reserve requirement.
- The NYCA 30-minute reserves requirement, adjusted for SCR/EDRP calls when applicable, which is 2620 MW plus estimated SCR/EDRP deployment. The figure represents this with a black solid line. Additionally, a dashed black line shows the sum of the amount of deployed DR by local utilities and the SCR/EDRP-adjusted NYCA 30-minute reserves requirement.

Figure A-124: Demand Response Deployments by NYISO and Market Outcomes

2024



Therefore, the difference between the solid black line and the scheduled 30-minute reserves indicates the size of the shortage in the market model; while the difference between the dashed black line and the scheduled 30-minute reserves indicates the size of the shortage that would have occurred without utility DR deployments.