2023 State of the Market Report for the New York ISO Markets

POTOMAC ECONOMICS

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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 the 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 2023.

The 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 2023

The NYISO markets performed competitively in 2023 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.

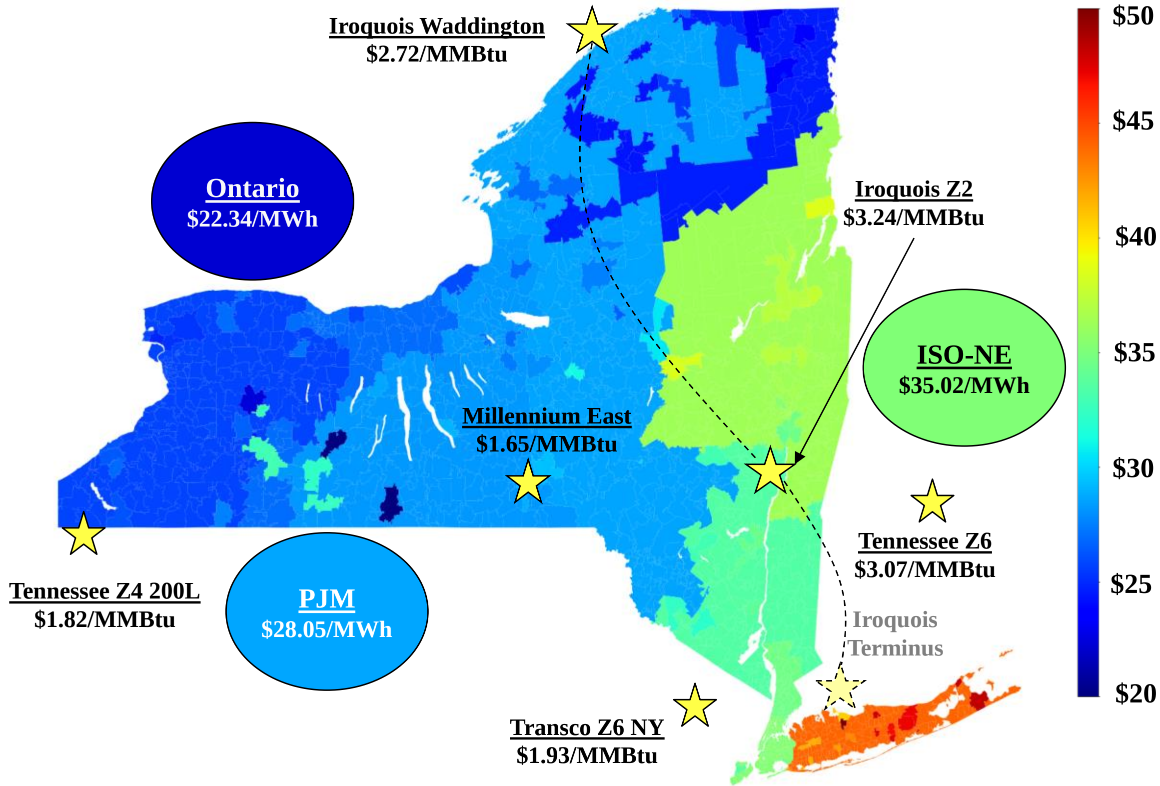
Natural Gas Prices

Natural gas prices and load levels are two key drivers of market outcomes. Average gas prices fell sharply from last year throughout the State. In most western regions and New York City, gas prices averaged below $2 per MMBtu in 2023. Other areas of eastern New York exhibited the lowest annual averages since 2020. Mild weather conditions combined with increased domestic production kept gas prices low throughout the year. (See Section II.C for details).

Energy Prices and Transmission Congestion

Average energy prices fell substantially from 2022 in Western New York (53 to 57 percent) and Eastern New York (58 to 65 percent) mainly because of lower gas prices and fewer transmission outages. Transmission congestion and losses in 2023 caused real-time prices to vary from $23.50 per MWh in the North Zone to $45.38 in Long Island on average. (See Section II.A)

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2023



Price reductions were larger in eastern New York because transmission bottlenecks across the Central-East interface were alleviated by: (a) fewer planned transmission outages related to construction of the AC Public Policy Transmission Projects, (b) the increased transfer capability from the newly-built projects, and (c) mild winter weather conditions which helped reduce congestion on gas pipelines flowing into eastern New York. Consequently, congestion revenues collected in the day-ahead market fell 69 percent from 2022, totaling $311 million in 2023. (See Section VI.A) Most congestion in 2023 occurred on two corridors: the Central-East Interface (53 percent of all congestion) and Long Island (19 percent of all congestion).

Capacity Market

Retirements of downstate peaking resources, along with fluctuations in the statewide and local capacity requirements, were the primary drivers of capacity price variations. The largest change occurred in New York City where average capacity prices rose to nearly $16 per kW-month (up 400 percent) for the 2023/24 Capability Year. Emission requirements set by the New York Department of Environmental Conservation (DEC) led to the retirement of approximately 800 MW of peaker capacity in-city in November 2022 and May 2023. These retirements, along with a 327 MW increase in the NYC ICAP Requirement, drove prices to historically high levels.

Statewide prices were also affected by the peaker retirements and an ICAP requirement increase of 338 MW, rising 50 percent from 2022. (See Section VII.A) Net imports of capacity from external control areas also fell sharply from the prior year, especially those from Quebec in winter months. Fluctuations in net imports from Quebec were the main cause for statewide capacity prices to rise from $0.95 per kW-month in November 2023 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 2023/24 Capability Year.

High capacity prices reflected the relatively low capacity margins statewide (~4.5 percent) and in New York City (~2.6 percent) for the 2023/24 Capability Year. Capacity price increases partially offset lower energy and ancillary service net revenues in 2023. (See Section II.B).

Investment Incentives for Public Policy Resources

The NYISO market provides price signals that motivate firms to invest in new resources, retire older units, and maintain their 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 12 GW of land-based wind and solar awarded contracts with NYSERDA under the Clean Energy Standard, just 1 GW has been deployed and over 8 GW have canceled their contracts. Similarly, all of the 8 GW of awarded offshore wind projects have canceled their 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 cost increases of around 30 percent since 2021, increased market risks, and interconnection and permitting obstacles. (See Section III.B)

To encourage investment under rising costs, 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 remaining under contract, we estimate total revenues (including federal and State subsidies) are likely sufficient to support the investment at the contracted price level. These subsidies are a major component of the investment incentives, providing 44 to 56 percent of revenues for land-based renewables and 61 percent for offshore wind. (See Section III.A)

It is important to note that large-scale deployment of renewables will drive down wholesale prices in locations 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 they 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 to wind generators relative to zonal averages (which are the basis for Index REC contract payments). This trend should 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 recently-announced State target of 6 GW by 2030. Market revenues have generally been too low to support investment even with State incentives. However, higher capacity prices in New York City and the new 30 percent federal Investment Tax Credit closed the revenue gap in 2023. We estimate net revenues of 4-hour and 6-hour storage in New York City would have surpassed the Cost of New Entry for the first time in 2023. (See Section III.A)

The Department of Public Service has proposed a new annual solicitation to procure 1 GW per year of bulk storage, using a new Index Storage Credit contract structure that would provide a partial hedge against NYISO market revenues. These developments could lead to an accelerated 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. Rising storage penetration will also affect other market revenues:

- *Energy and reserve revenues*: 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.
- *Capacity revenues*: 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 are beneficial. Storage investment is likely most efficient when it is proportionate with renewable development or in locations where it can help manage congestion caused by fluctuating renewable output. (See Section III.C)

Capacity Market Performance

The capacity market is NYISO’s primary means to meet resource adequacy and other planning requirements. It provides incentives to invest in and maintain needed resources and has generally been effective. However, several growing challenges will require changes to allow the market efficiently signal the location and type 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 New York. In some areas, capacity is bottlenecked and overvalued because the capacity market does not recognize that it is not fully deliverable (such as Staten Island within the New York City region). 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 resources in bottled areas and under-paying resources in higher-value areas, which drives up capacity prices overall and retains excess capacity in service. 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. Legacy resources in bottled areas have incentives to not retire, thereby preventing new entrants from entering those areas.

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 determined 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 all of the LCRs to be set at the TSL floors for the 2024/25 Capability Year. In Section VIII.E, we discuss the inefficiencies that occur when LCRs are set based on TSLs:

- *Overcompensation of some resource types*: Some resources are assumed to provide less transmission security in the studies than they are accredited for in the capacity market. These include demand response (SCRs), intermittent renewables, and large resources whose size causes the transmission security planning contingency to increase. The presence of these resources causes the TSL-based LCRs to increase. Hence, these resources are overcompensated and have inadequate incentives to take actions that would improve system reliability. In the 2024/25 Capability Year in New York City alone, we estimate these resources will be over-compensated by up to $47 million.

- *Overcompensation of surplus capacity*: The capacity demand curves are designed to allow prices to fall as the amount of surplus capacity rise 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 anchored by the TSL requirement level.

To address these issues, we make two recommendations. First, pay resources for capacity according to the requirements which they contribute to meeting (Recommendation 2022-1). Second, 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

Beginning in May 2024, NYISO adopted a new approach for compensating resources based on their marginal reliability value. Each class of resources is compensated based on its Capacity Accreditation Factor (CAF), which is determined 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)

Section VIII.G examines the need for improvements to modeling winter fuel limitations in more detail. NYISO recently proposed improvements to its representation of gas-only units with limited fuel supplies in the resource adequacy model for implementation in the 2025/26 Capability Year, but its proposal would not model fuel inventory levels of oil and dual fuel units. NYISO relies heavily on oil and dual-fuel units with limited on-site inventories during cold weather, so management of fuel inventory levels and replenishment arrangements could become pivotal for reliability as winter load rises in the coming years in New York. Hence, it will be essential to consider fuel inventories in the resource adequacy model to set appropriate ICAP requirements, to identify winter reliability risks, and to compensate various resource types efficiently (including gas-fired generators, renewables, and storage).

NYISO's rules for determining the installed capability of capacity resources tend to overestimate the capacity of many nuclear and fossil-fuel generators. This includes "emergency capacity" that is never committed in practice, resources dependent on ambient water temperatures or humidity levels, and cogeneration units that face limitations associated with their steam host demand. We estimate up to 1.6 GW of these categories of capacity were functionally unavailable on peak days in Summer 2023. (see Section VIII.D). NYISO has begun to address these concerns by proposing new requirements starting with the 2025/26 Capability Year, including: (a) placing 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 if appropriate. These efforts should help develop more accurate DMNC ratings. However, nearly 8 GW of fossil-fuel generation in Zones G through K are affected by tidal levels, which are not addressed in the NYISO's proposed changes. We recommend that NYISO continue to pursue efforts to adjust DMNC test results of these units to more accurately determine their capacity at expected peak water temperatures and tidal levels.

Seasonal Capacity Market

Resource adequacy risk is growing in winter relative to summer due to a combination of factors, including 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 in the mid-2030s, and winter reliability risk is expected to surpass summer risk earlier because of winter 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: (1) adjust summer and winter demand curve parameters to account for seasonal reliability risk, and (2) accredit generators considering their winter fuel supply arrangements. 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. Several problems will emerge from this framework, including:

- Fuel supply arrangements (e.g., firm gas transportation) will not affect capacity prices or CAFs. 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.

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. 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.

To address these issues, we recommend disaggregating NYISO's capacity zones (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 (2012-1c).

Improvements to Transmission Planning Process

In Section IV.B, we provide an overview of NYISO's centralized transmission planning process and suggest improvements so that more efficient projects can be selected. In recent years, large-scale transmission planning takes 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 significant 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) For example, NYISO's evaluation methods overvalued capacity-related benefits of the selected Long Island Offshore Wind Export PPTN project in 2023 by a very significant margin. 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 the performance of the market 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 will become increasingly important as the New York system integrates higher levels of intermittent renewable resources and the supply from fuel-secure generation declines.

Dynamic Reserve Needs

As intermittent generation is added to the system, patterns of congestion and operating reserve constraints are becoming more variable. Consequently, NYISO does not schedule operating reserves efficiently when local reserve needs could be met more cost-effectively by reducing imports to an area and generating more power internally rather than holding reserves on units in the area. Accordingly, we have recommended NYISO dynamically determine the optimal amount of reserves needed for reliability in local areas and systemwide. NYISO is working to implement such "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. While shortage conditions arise in 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 the need for out-of-market actions and to reflect the value of reserves for maintaining reliability. In Section VI.A, we identify conditions when the operating reserve demand curves are currently 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. Therefore, 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 unreasonably aggressive shortage pricing in neighboring markets. Resources selling into the ISO-NE and PJM markets could receive $5000 to $8000 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 flows over a transmission facility exceed its limit, which happens when NYISO's dispatch model lacks the resources to reduce flows. The NYISO market experienced such localized shortages in roughly 5 percent of intervals in 2023.

In mid-November 2023, the NYISO implemented *Constraint Specific Transmission Shortage Pricing*, which aligns the MW steps on the Graduated Transmission Demand Curve (GTDC) with the Constraint Reliability Margin (CRM) for each facility. This should improve correspondence between shadow prices and the severity of transmission constraints. However, given the recent implementation of this enhancement, we did not evaluate the performance of the new pricing logic in this report but plan to do so in future reports.

Despite the market enhancement, we have identified an issue that undermines pricing efficiency by preventing the market software from recognizing some transmission shortages in real-time market operations. Specifically, "offline GT pricing" causes congestion pricing to fail to show the severity of actual transmission shortages. The current pricing model in NYISO's real-time market assumes that offline GTs are able to respond to dispatch instructions in 5 minutes even though they actually cannot do so. Consequently, NYISO is compelled to compensate for these differences by over-constraining transmission in some areas heavily reliant on gas turbines. Therefore, we recommend the 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 implemented at the end of 2020, we have identified one issue in the real-time pricing algorithm. This occurs when the real-time scheduling software economically starts gas turbines offering minimum run times longer than one hour. These units are treated as if they have a one-hour minimum run time, but the pricing algorithm does not treat them as eligible to set LBMP. Ultimately, this prevents prices from 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. 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. 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 expected IPR dispatch performance is poor. 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 stronger disincentives for over-generation by generators with negative incremental costs. (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, and this information is used to assist market participants in scheduling external transactions more efficiently. The key findings of our evaluation include:

- The CTS process at the New England interface continued to perform better and produce more savings than at the PJM interface in 2023, largely because of the effects of the much higher fees and uplift costs imposed on transactions at the PJM interface.
- Firms exporting to PJM interface require much larger price spreads (~$7.5 per MWh) between the markets to profit from the transactions, and they offer much lower quantities.
- The NYISO's export fees are much higher than PJM's and may reduce the revenues received from CTS transactions – $0.7 million in 2023. A lower export fee might result in higher revenues because CTS transactions would be profitable in many more hours.

It is unlikely that CTS with PJM will function effectively while transaction fees and uplift charges are large relative to the expected value of spreads between markets. Hence, we recommend eliminating (or significantly reducing) transaction fees and uplift charges 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.B 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 used to satisfy bilateral contract terms, regardless of their efficiency. The most significant inefficiencies we identified were associated with the two lines that normally flow 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"). In 2023, the operation of these lines, as per the wheeling agreement, resulted in: *higher* production costs by an estimated $10 million, *increased* CO_2 emissions by an estimated 260 thousand tons, and *higher* NOx emissions by an estimated 454 tons.

The ConEd-LIPA wheeling agreement continues to use the 901 and 903 lines in a manner that raises production costs inefficiently. As offshore wind and other intermittent generation resources are integrated into New York City and Long Island, the operational flexibility of these lines would become increasingly valuable 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 SectionV.F 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.

Most residuals resulting from "Qualifying" changes in modeled transfer capacity between TCC auctions and day-ahead markets are allocated to the responsible TOs, while any remaining shortfalls and surpluses are assigned in proportion to TCC auction revenues received by each TO. This method was used to allocate $57 million in net shortfalls among all TOs for both 2021 and 2022 and a net surplus of $5 million for 2023. This does not align with cost causation principles, which fails to incentivize TOs to operate their transmission equipment efficiently and may encourage overselling the capability of the transmission system in the TCC auctions.

We recommend the NYISO revise the allocation of day-ahead congestion residuals that is currently based on TCC revenues. 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. (See Section VII.D and Recommendation 2023-1).

Out-of-Market Actions

Guarantee payments to generators fell by roughly 40 percent from 2022 to $59 million in 2023. The decrease was driven primarily by lower natural gas prices and the elimination of "NOx Bubble" reliability commitments. Fewer supplemental commitments and less frequent OOM actions were also important contributors. (See Section VI.E)

New York City

Because 800 MW of older peaking resources retired before the 2023 Ozone Season, supplemental commitments for "NOx Bubble" requirements were eliminated. Consequently, requirements to be able to respond to multiple contingencies were the primary driver of supplemental commitments in 2023. Nearly $31 million of guarantee payments were made to units committed for this purpose. 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 2017-1)

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 the 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

NYISO has integrated five 69 kV constraints into its day-ahead and real-time markets since April 2021. This integration has resulted in a significant decrease in the number of OOM dispatches, with OOM hours in Long Island down more than 60 percent in 2023 from 2019 levels (and 30 percent lower than 2022), which has led 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)

Despite low load conditions across much of the summer muting the need for frequent reliability commitment in Long Island this year to address multiple contingencies, 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 Section V.E and Recommendation 2021-2)

Upstate New York

OOM commitments in upstate regions increased in 2023 primarily to satisfy the multi-contingency criteria in the North Country load pockets on 143 days. Modeling reserve requirements in local load pockets would improve scheduling efficiency and establish more efficient market signals for new investment.

Overview of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2023, 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 five 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 XII. In total, we have 25 outstanding recommendations that are discussed in that section. In addition, the NYISO moved forward with market reforms that would address one recommendation from our previous State of the Market Report.

High Priority Recommendations in the 2023 SOM Report

Number	Section	Recommendation	NYISO Project Scope: (2024 / 2025)
Energy Market Enhancements – Pricing and Performance Incentives			
2017-1	VI.E	Model local reserve requirements in New York City load pockets.	N/A[1]
2015-16	VI.A	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	*Dynamic Reserves:* (Market Design Complete & Prototyping & FRS / Software Deployment)
2016-1	Appx. V.D	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2017-2	VI.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	N/A
Capacity Market – Design Enhancements			
2022-4	VIII.C	Implement more granular capacity zones and a dynamic process for updating the zones.	*Granular Capacity Market Pricing:* (Issue Discovery / Continuing)
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*

1 The 2023 Market Vision includes a 2027-2028+ project called *More Granular Operating Reserves* to address Recommendation 2017-1 following the deployment of the *Dynamic Reserves* project in 2026.

I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2023.[2] 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.

[2] 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,[3] the markets should 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 should still 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 XII of the report provides a number of recommendations that are intended to achieve these objectives.

[3] 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 2023. 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.

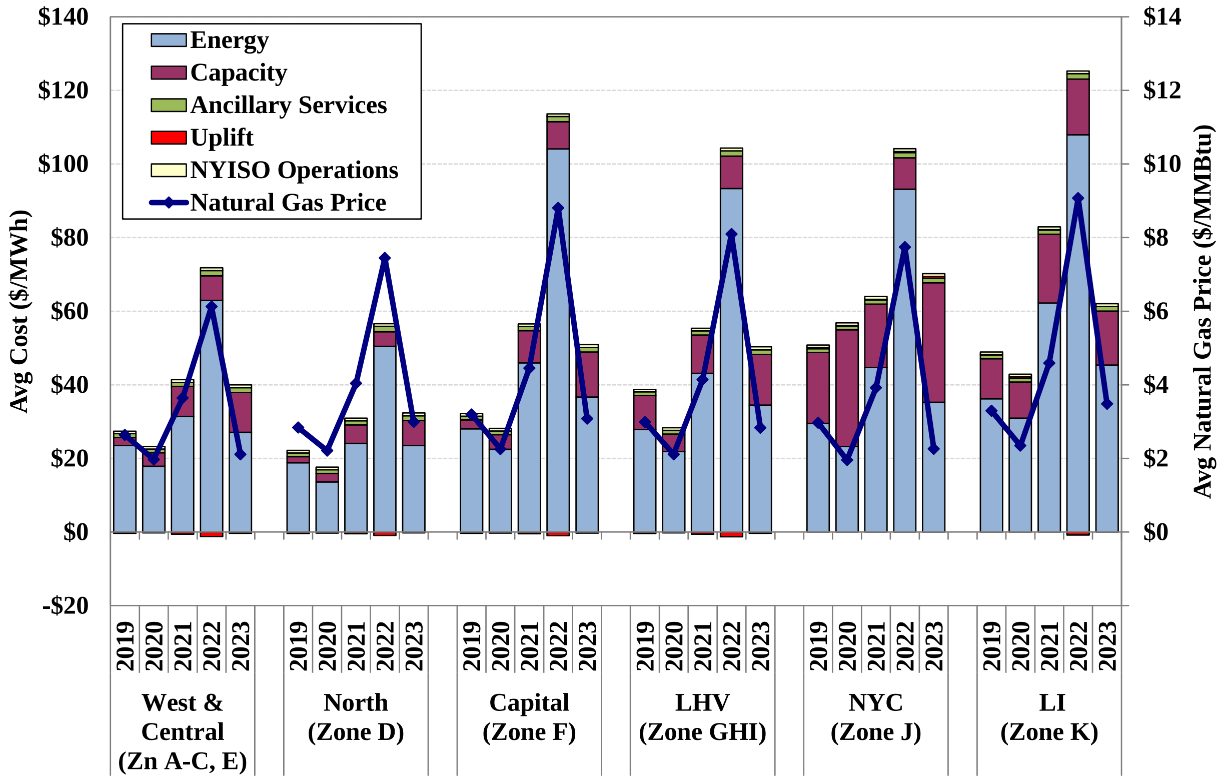
A. Wholesale Market Costs

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 the energy consumption in that area.

All other components are the costs divided by the real-time load in the area.[4]

Figure 1: Average All-In Price by Region
2019 - 2023



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

In 2023, average all-in prices ranged from $34 per MWh in the North Zone to nearly $72 per MWh in New York City. All-in prices fell 32 to 54 percent from 2022 mainly because of lower energy prices, which was due to the following factors:

- Natural gas prices fell from 2022 levels because of increased domestic production and mild weather, especially during the winter. Fuel prices are evaluated in Subsection C.
- Mild weather conditions in the winter and summer contributed to a significant reduction (4 percent) in average load and just one hour when load surpassed 30 GW systemwide.
- Transmission congestion fell sharply because of fewer transmission outages and the installation of new transmission.[5] Congestion patterns are evaluated in Section VII.

Lower energy prices were partially offset by rising capacity prices in most areas, which increased by almost 4 times in New York City and by 56 to 71 percent in all other zones except Long Island, which fell by 3 percent. The reasons for these increases are discussed in Section VIII, but include the retirement of over 700 MW of peaking units in New York City prior to the Summer 2023 Capability Period, as well as a higher Installed Reserve Margin (IRM) and higher Locational Capacity Requirements (LCR) in some areas.

B. Net Revenues for Existing Generators

As the resource mix shifts away from conventional fossil-fuel generation, it is important to provide market incentives to retire of the least valuable generators (rather than flexible resources that are more effective for integrating intermittent generation) and to maintain generation in a reliable condition. The following evaluation considers 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 2021 to 2023. 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 generation facility in reliable condition, including plant-level and other costs that may be shared across multiple units.[6] However, a firm may not be able to avoid all such costs by retiring just a single unit at a facility, and a firm may be able to avoid a substantial portion of the cost 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

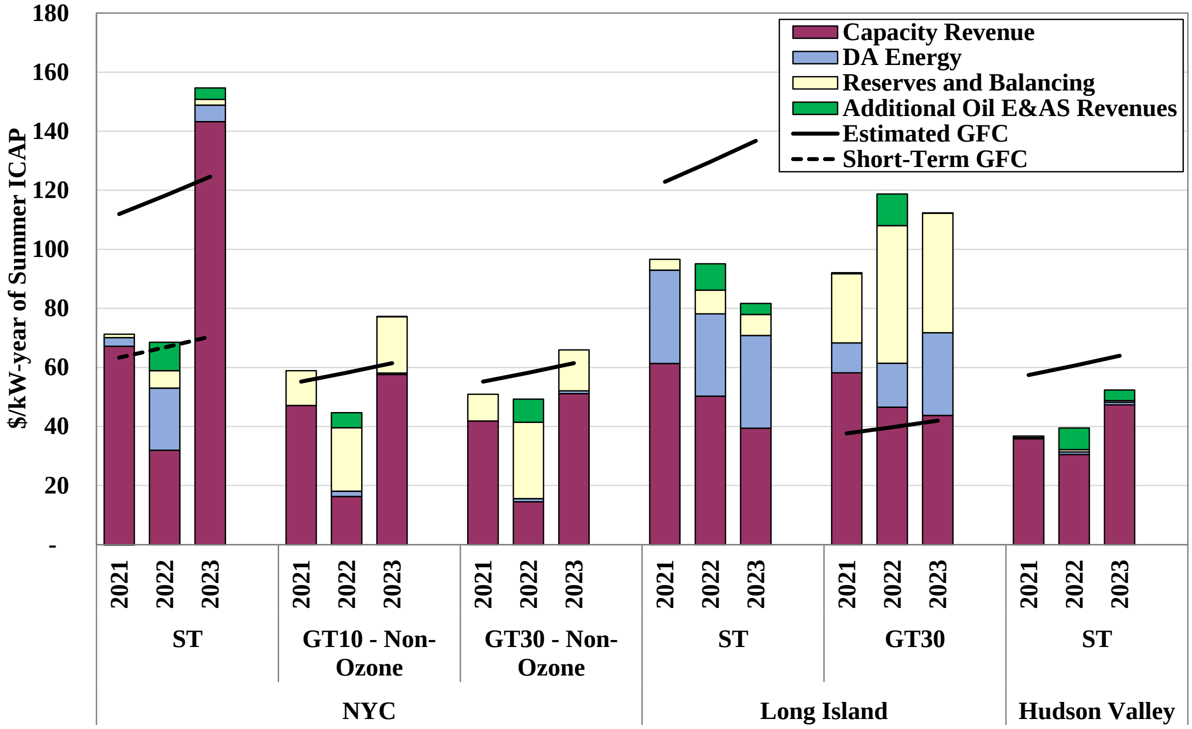
5 Transmission outages for the AC Public Policy Transmission Segment A and B projects reduced Central-East transfer capability in 2022, contributing to significantly higher levels of congestion than usual.

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

capital expenditures. Even the "Short-Term GFC" includes some plant-level costs that would be difficult to avoid by retiring a single unit.[7,8]

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.[9]

Figure 2: Net Revenues and Going-Forward Costs of Existing Units
2021 – 2023



Revenues for existing fossil units were mainly driven by fluctuations in capacity prices. Net revenues increased in 2023 due to higher capacity prices in NYC and in the Lower Hudson Valley. In Long Island, net revenues fell because of capacity prices fell from 2022. E&AS net revenues fell in all regions from 2022 due to lower congestion and lower natural gas prices.

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

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7 The "Short-Term GFC" includes estimated fixed O&M costs, property tax and administrative costs with all major maintenance and capital expenses excluded.

8 For details regarding net revenues and GFCs for existing units, see Appendix subsections VII.A and VII.B.

9 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.

GFCs in all areas. 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. The only location where net revenues for a steam turbine exceeded the estimated GFC was in New York City because of the sharp increase in capacity revenues there in 2023, although they exceeded the short-term GFC in the other years there.

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 2023 even if they had operating 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 XII 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 2020 to 2023 for several key indices.[10]

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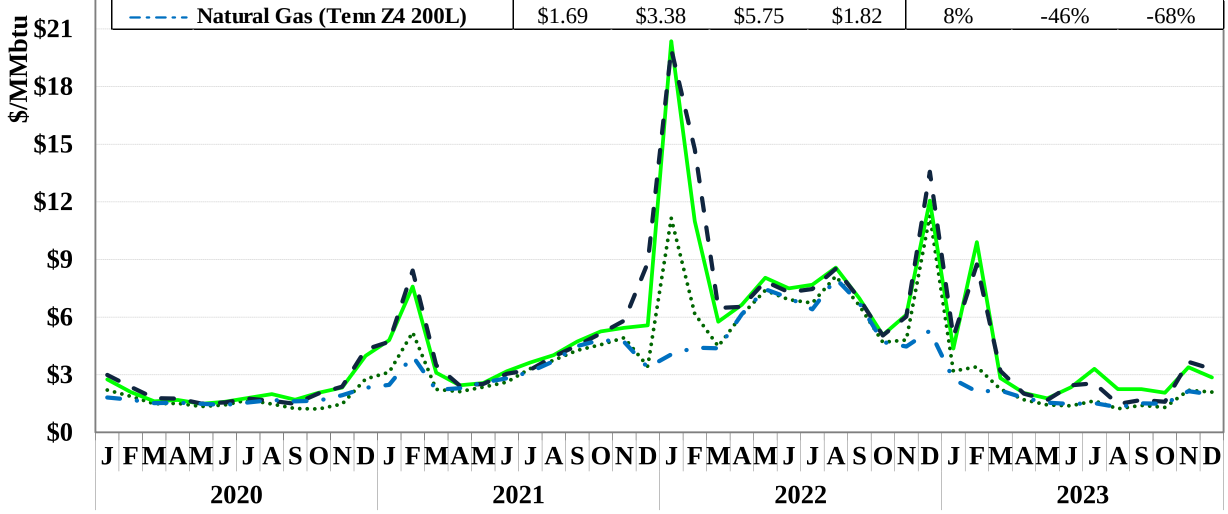
[10] Section I.B in the Appendix shows the monthly variation of fuel prices and provides our assumptions about representative gas price indices in each region.

Figure 3: Average Fuel Prices and Real-Time Energy Prices
2020 – 2023

	Avg Price per Year				2023 Value vs Prior Years		
	2020	2021	2022	2023	2020	2021	2022
Natural Gas (Tennessee Zn6)	$2.13	$4.68	$9.20	$3.11	46%	-33%	-66%
Natural Gas (Iroquois Zn2)	$2.09	$4.36	$8.82	$3.28	57%	-25%	-63%
Natural Gas (Transco Zn6 (NY))	$1.64	$3.49	$7.04	$1.94	18%	-45%	-72%
Natural Gas (Tenn Z4 200L)	$1.69	$3.38	$5.75	$1.82	8%	-46%	-68%



After reaching a new decade-high value in 2022, natural gas prices fell by 63-to-72 percent in 2023. The large annual decrease in gas prices was driven by increased domestic gas production and mild weather conditions across the winter. New York regional gas prices did not experience significant winter volatility in 2023, outside of a few days in early February.

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 2014: (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 4 percent lower than in 2022 and the lowest level observed in more than a decade. Much of this decrease was attributable to mild weather and increased penetration of Behind-the-Meter (BTM) solar. Estimated BTM solar reached roughly 2.8 GW on the peak load day of 2023.

Table 1: Peak and Average Load Levels for NYCA
2014 – 2023

Year	Load (GW)			
	Summer Peak (as Reported)	Summer Peak (Reconstituted)	Winter Peak	Annual Average
2014	29.8	29.8	25.7	18.3
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

E. Generation by Fuel Type

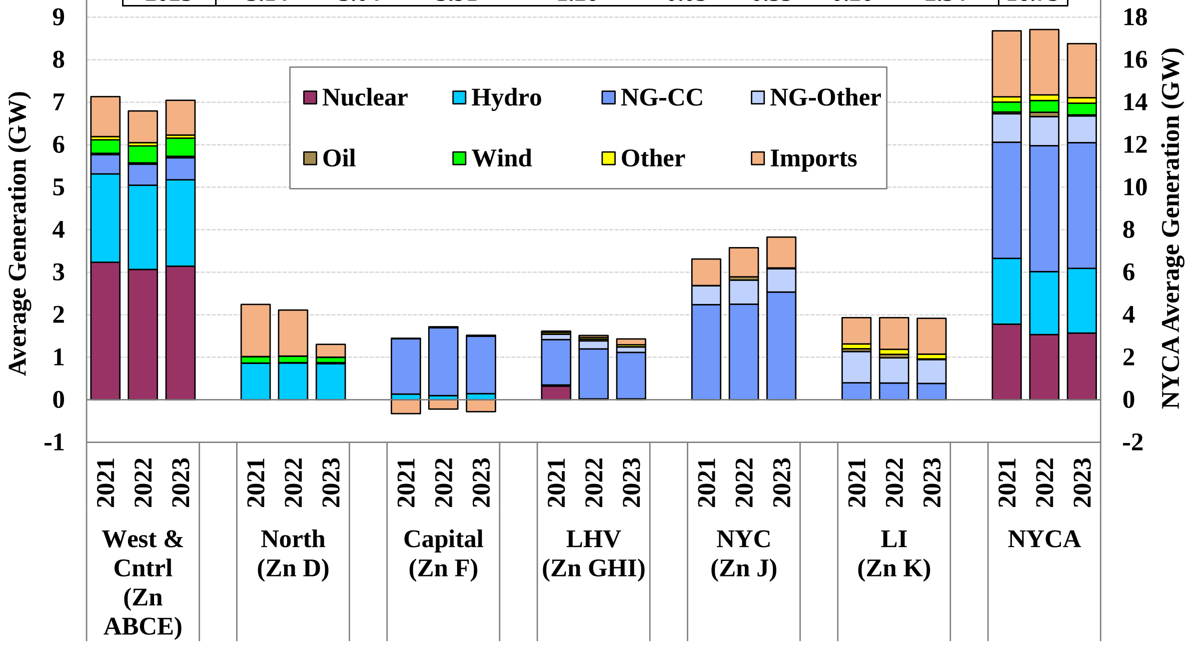
Variations in fossil fuel prices, retirements and mothballing of old generators, and the additions of new gas-fired generation in recent years have led to concomitant changes in the mix of fuels used to generate electricity in New York. Figure 4 displays annual generation by resource type from 2021 to 2023 (including net imports).

Net import levels are assigned as follows: (a) Ontario imports in the West & Central Zones; (b) Quebec imports in the North Zone; (c) imports over the primary PJM interface are split 7 percent to NYC, 47 percent to the Lower Hudson Valley, and 46 percent to the West & Central Zones; (d) net imports over the primary ISO-NE interface are split 55 percent to the Capital Zone and 45 percent to the Lower Hudson Valley; and (e) the Scheduled Lines to their applicable regions (i.e., Cross Sound Cable, Neptune Cable, and 1385 Line in Long Island and the HTP and Linden VFT Lines in NYC). Since there were net exports to ISO-NE, they are shown as negative values.

Gas-fired resources accounted for the largest share of internal generation in 2021 and the majority in each of the past two years. This increase is due in part to the construction of new combined cycle facilities in the Hudson Valley and the retirement of the Indian Point nuclear generators in the same region.

Figure 4: Generation by Type and Net Imports to New York
2021 - 2023

Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Imports	Total
2021	3.56	3.09	5.47	1.34	0.08	0.47	0.25	3.11	17.36
2022	3.06	2.97	5.92	1.37	0.21	0.55	0.26	3.08	17.42
2023	3.14	3.04	5.91	1.26	0.05	0.55	0.26	2.54	16.75



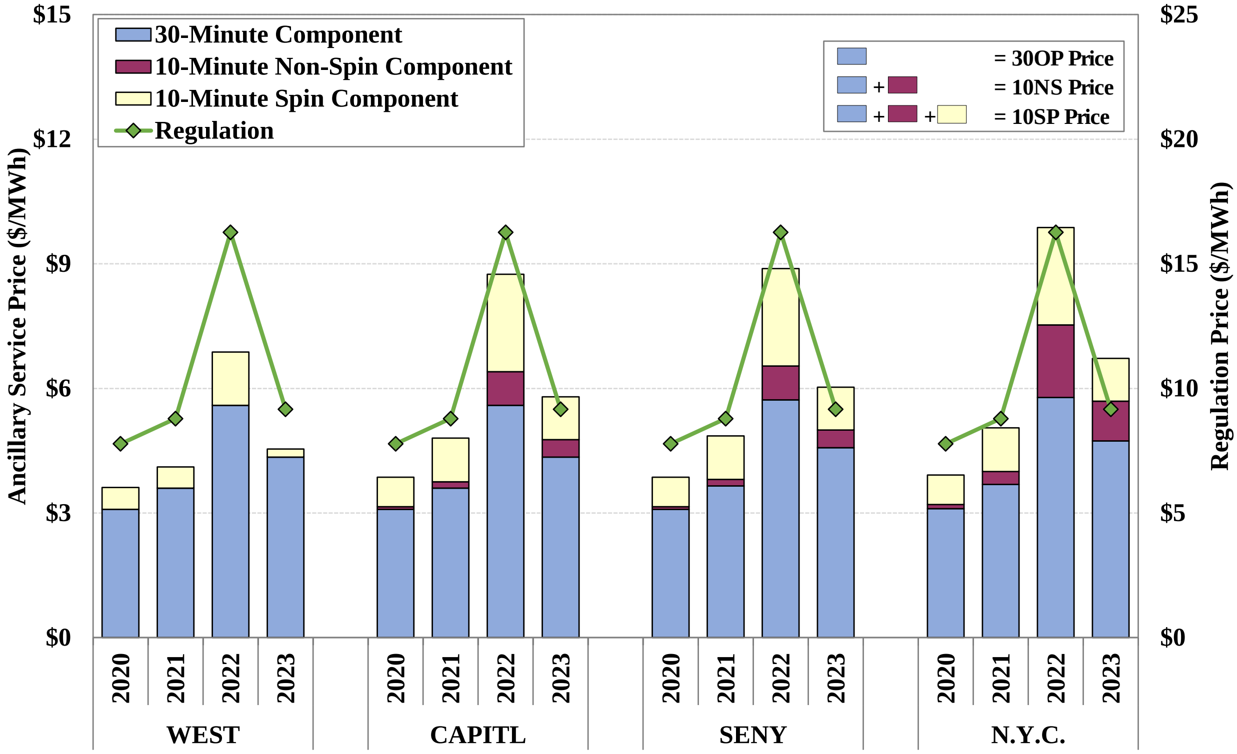
Before 2021, over half of internal generation came from hydro and nuclear units. With the retirement of Indian Point 2 in 2020 and Indian Point 3 in 2021, the share of internal generation from nuclear and hydro resources combined fell to 43 percent in 2023. Net imports fell by nearly 540 MW from 2022 because of a sharp decrease (~780 MW) in net imports from Quebec. Imports from the region fell in the Spring due to complications from the 2023 Canadian wildfires and remained low through the end of the year.

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.[11]

11 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.

Figure 5: Average Day-Ahead Ancillary Services Prices
2020 - 2023



Average day-ahead prices for all reserve products fell in 2023, consistent with the decline in energy prices and the opportunity costs of reserve providers.[12] In 2023, reserve prices were significantly higher than in 2020 and 2021, which is largely attributable to the retirement of roughly 700 MW of peaking units that were frequently scheduled for reserves prior to the summer of 2023.

12 See Appendix Section II.D for additional details about reserve offer patterns.

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
- Signals for investment in energy storage resources that facilitate the integration of intermittent renewables (subsection C).

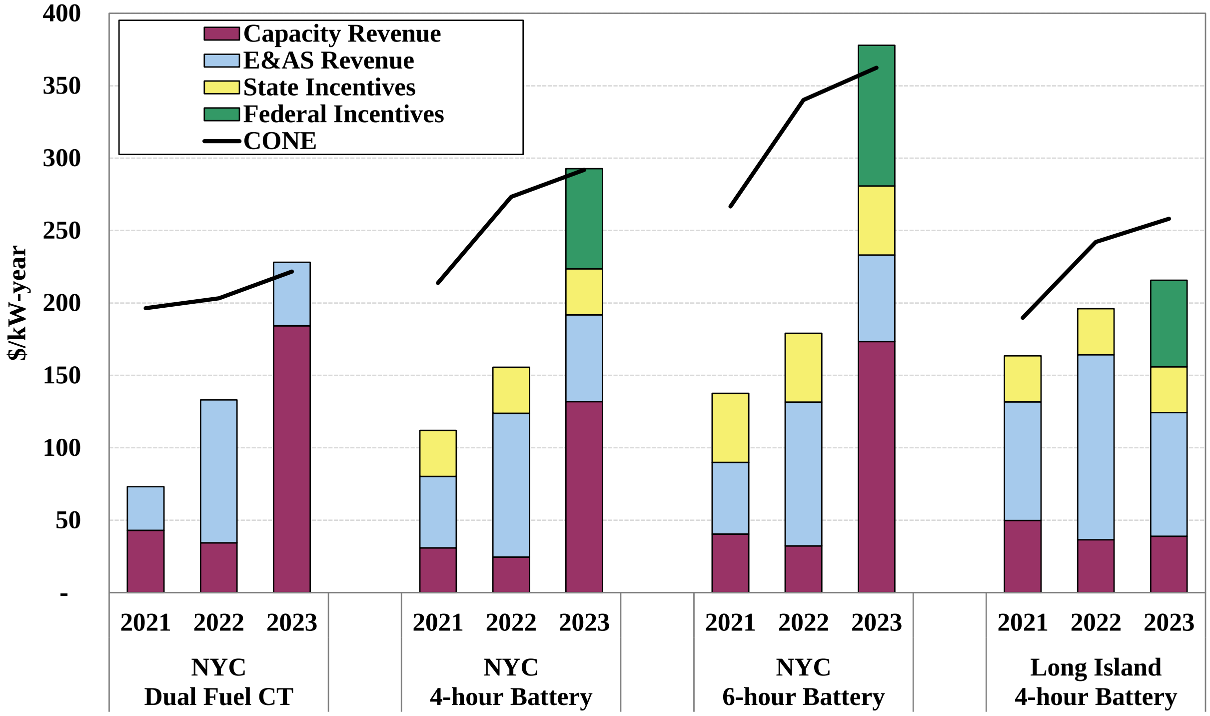
A. Incentives for Investment in New Generation

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 costs of new entry (CONE) in 2023. 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.[13] 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.[14]

Figure 6: Net Revenue and Cost of New Entry for New Dispatchable Resources
2021 – 2023



The profitability of generation investment varies by technology and zone, and it has been influenced by volatility in energy and capacity markets over the past three years. In addition to NYISO market signals, availability of federal incentives plays a major role in the profitability of potential projects. We observe the following for specific technologies:

Gas-fired Combustion Turbines – Estimated annual revenues for a new CT in NYC were roughly equal to the CONE in 2023. Retirements of peaking plants in 2022 and 2023 to comply with

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13 The cost of capital for combustion turbine and storage technologies was assumed to be equal to the merchant weighted average cost of capital (WACC) from NYISO's latest Demand Curve Reset study, while the cost of capital for renewables is assumed to be a hybrid between merchant and regulated cost of capital that reflects the large share of subsidy payments with 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.

14 Details on estimated net revenues can be found in Appendix Section VII. Further discussion of battery storage net revenues can be found in Subsection C of this section. We estimate state incentives for storage using the levelized value of the $75 per kWh of installed capacity NYSERDA's Bulk Storage Incentive, which would have been available to projects entering during the study period. The PSC is currently considering a new incentive program to encourage investment in energy storage.

state regulations resulted in a large increase in capacity revenues, as New York City currently has minimal surplus above its Locational Capacity Requirement (LCR, see Section VIII.A). However, recent permitting decisions suggest a new combustion turbine may not be deemed compliant with state climate law.[15]

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.[16] In New York City, we estimate that new 4-hour and 6-hour storage would earn revenues similar to their CONEs due to the increase in capacity prices for the 2023-24 capability year. The economics of storage are heavily supported by state and federal incentives. We estimate that about 35 to 44 percent of storage revenues at 2023 prices would be from subsidies.

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 value of storage to decline.[17] 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 2021 through 2023 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.[18]

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

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15 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.

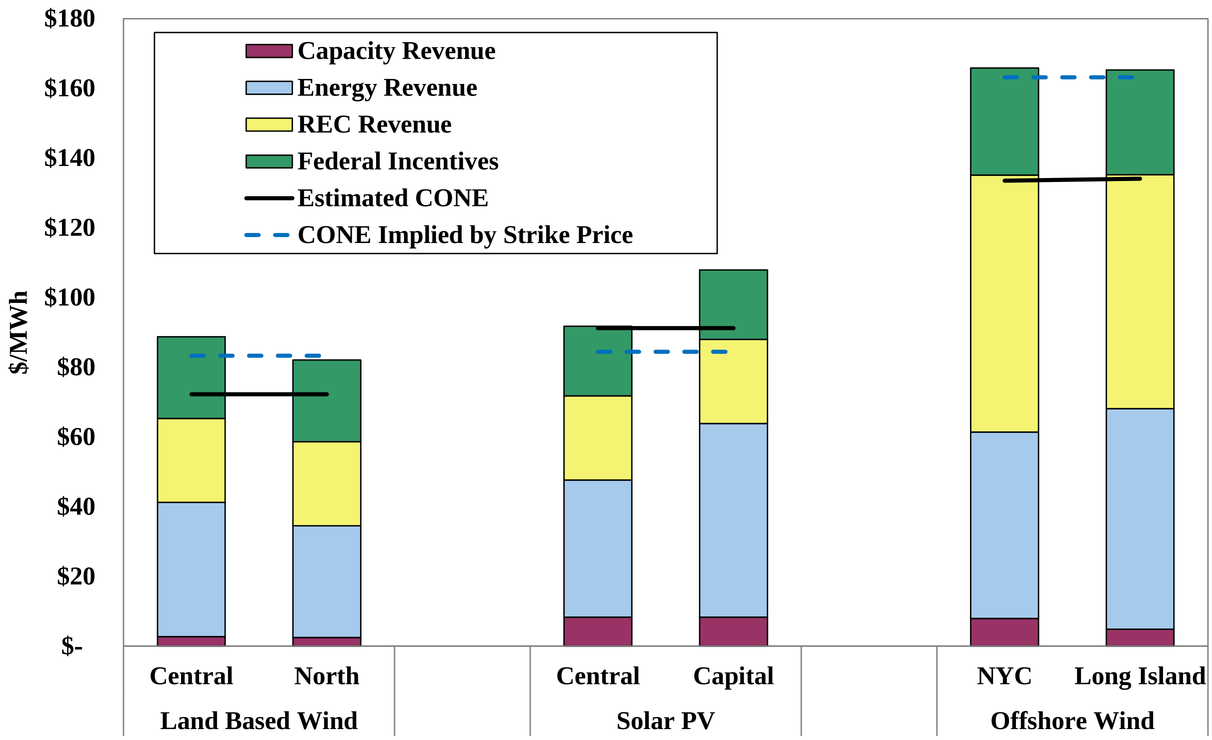
16 McGuire Woods, "Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects", December 27, 2022, available here.

17 Figure 6 assumes the final CAFs calculated for the 2024/25 capability year under the new Capacity Accreditation framework. These are 68.8 percent for 4-hour storage in NYC, 90.4 percent for 6-hour storage in NYC, and 78.9 percent for 4-hour storage in Long Island. See capacity accreditation webpage, here.

18 See Appendix VII.C for detailed assumptions. Average strike prices include projects with active projects and Index REC prices reported by NYSERDA as of March 2024. NYSERDA reports contract prices in nominal dollars; we convert these reported prices to a real $2023 price with equivalent present value over the lifetime of the project. We add revenues from federal incentives to the strike price to derive the 'implied' CONE.

accounted for approximately 56 percent of revenues for land-based wind, 44 percent of revenues for solar PV, and 61 percent of revenues for offshore wind.

Figure 7: Net Revenue and Cost of New Entry for New Renewable Generation
2021 – 2023



For land-based wind, the average Index REC Strike Price of resources with active contracts exceeds the estimated CONE. For offshore wind, the average Index REC Strike Price significantly exceeds the estimated CONE. It may be the case that site-specific development costs result in actual CONE values that are higher than the estimated CONE for wind projects and lower for solar projects. The difference between strike prices and CONE values may also reflect developers' expectations that their total market and REC revenues under the Index REC framework will differ from their contract strike price. We discuss the status of renewable investments and the market risks of projects with Index REC contracts in the next subsection.

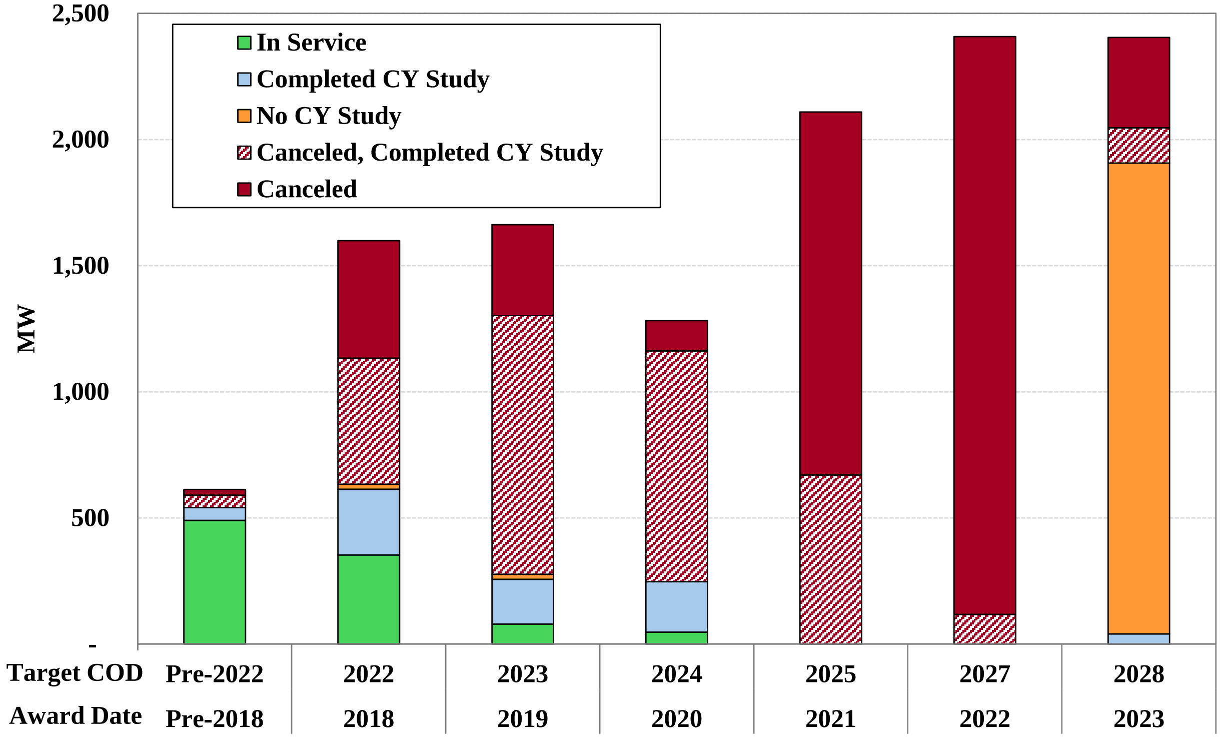
B. Long-Term Incentives for Investment in Renewable Generation

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 resource-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), with their status in NYISO's interconnection queue as of March 2024. Awards that NYSERDA indicates have been canceled are shown in red.[19]

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



Overall, while over 12 GW of Tier 1 awards have been announced under the CES: just 8 percent have entered service, while 70 percent have been canceled and the remainder have not moved forward with construction. Land-based wind account for nearly all of the projects that have entered service under the CES (~850 MW), while over 75 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

[19] Data taken from NYSERDA's renewable project database (see here) and NYISO's Interconnection Queue as of March 2024. Initial COD Targets are from NYSERDA announcements of solicitation results (see here).

(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.

- *3 GW of energy storage by 2030* – The NYPSC is considering 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 550 MW with an average duration of 3.3 hours have been awarded incentives under the state's bulk storage incentive program since 2019.[20] Of these projects, 29 percent have been canceled and just 7 percent have been completed. The NYDPS and NYSERDA have proposed a new three-year process to procure 3 GW of bulk storage projects annually starting in 2024.[21]

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.[22] The remainder of this subsection evaluates NYISO market incentives for investment in renewable generation.

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

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

22 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

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 would rely on wholesale market revenues will be harmed by the resulting decline in energy and capacity net revenues. This may affect projects that won an earlier solicitation by hampering their ability to obtain financing and reducing their incentives to complete the permitting and construction of the project.[23]

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 from 2021 to 2023. Each point shows the difference between the generation-weighted real-time LBMP and the all-hours day-ahead average LBMP for one technology and location. For all resources, the technology discount is calculated based on generic average hourly capacity factors in each month. For land-based wind, nodal discounts are calculated for wind projects that have been in service since 2021 or earlier, using actual generator output and LBMP data.

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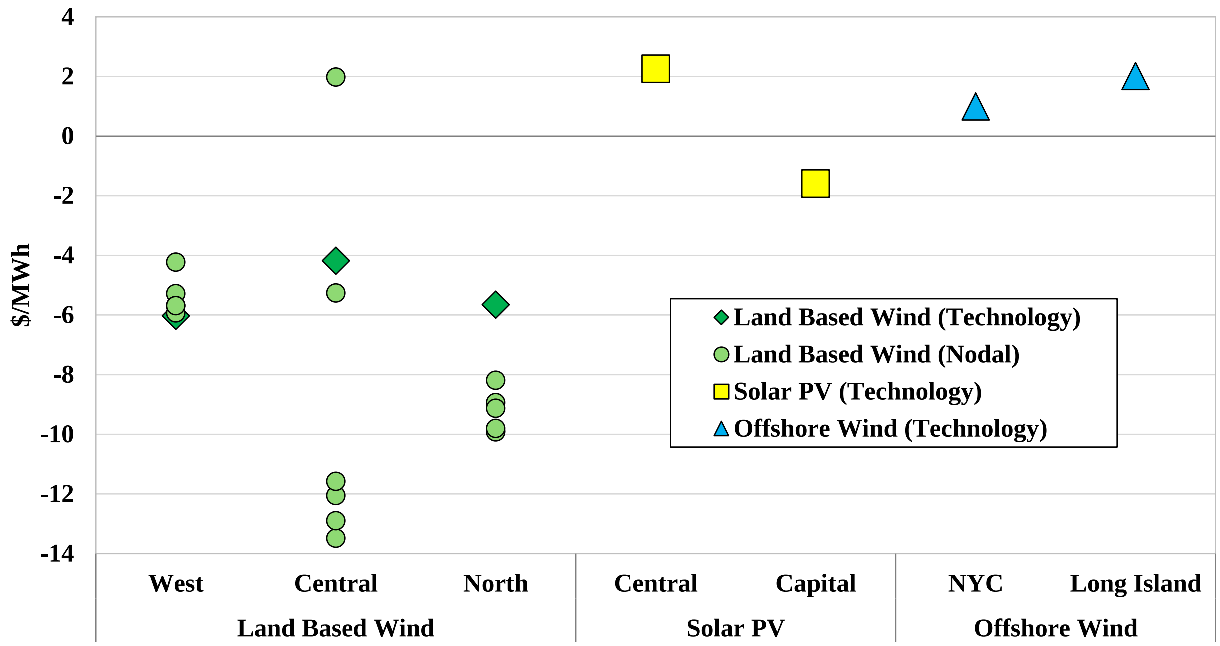
evaluation commissioned by NYSERDA lists "financial viability of the project at the bid price" as a driver of project delays and attrition. See NYSERDA August 10, 2020 Petition in NYPSC Case 15-E-0302, at p. 7. Conversion of Fixed REC contracts to Index RECs mitigates but does not eliminate projects' revenue risks.

23 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.

Figure 9: Renewable Technology and Nodal Discounts, 2021-2023



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, $14 per MWh in Zone C, and $10 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 $11 per MWh (see Figure 7 earlier in this section).

Technology discounts for solar PV and offshore wind (based on generic capacity factor profiles) were small from 2021 to 2023. However, our analysis of data from NYISO's 2021 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.[24] Our comparison of estimated renewable CONEs to strike prices of active projects in 7 suggests that current offshore wind strike prices may include a cushion against nodal and technology discounts, while current solar PV strike prices do not. This increases the financial risks to these solar 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 investors to avoid projects in oversaturated locations or technologies. This will lower the

24 See Section III.B of our 2022 NYISO State of the Market Report, available here.

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.[25] 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 simply been insufficient to justify investment until very recently at premium locations, even after accounting for state incentives.

The New York DPS and NYSERDA recently proposed annual solicitations for bulk storage projects beginning in 2024 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.[26] 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 are 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.

Figure 10 shows estimated net energy and ancillary services revenues for 4- and 6-hour battery storage in New York City using alternative bidding strategies. We model storage revenues assuming that the battery offers a portion of its capacity as 10-minute spin reserves in the day-

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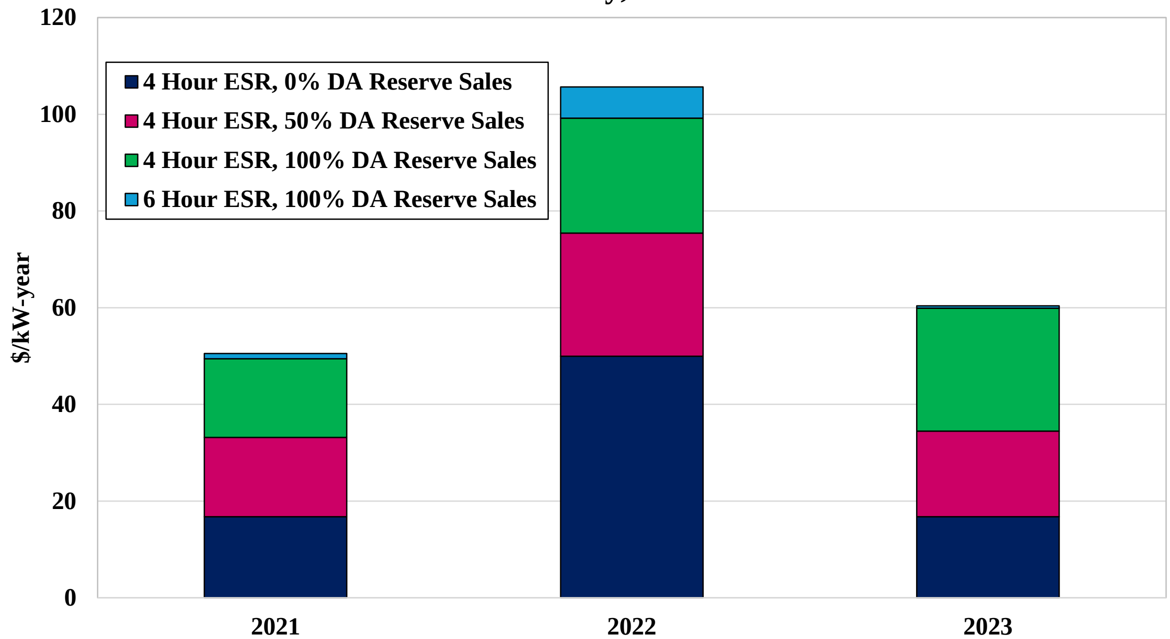
25 A related phenomenon is that future projects with higher REC payments than existing resources may profit by 'undercutting' the negative offer of the lower-REC project in NYISO's merit order dispatch, causing the new project to earn profit by "cannibalizing" the REC of the earlier project. See MMU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

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

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.[27] 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 incrementally as large shares of its capacity are offered in the day-ahead reserve market.

Figure 10: Estimated Energy Storage Energy and Ancillary Services Revenues New York City, 2021-2023



This analysis shows that revenues under all strategies were highest in 2022, which had generally higher and more volatile energy prices compared to 2021 and 2023. 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 six-hour battery would have earned only $3 per kW-year more on average compared to a four hour battery, when following the highest-revenue strategy (100 percent day-ahead reserve sales).

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

27 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.

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 wind and solar resources cause negative prices to occur frequently.[28] 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 will accredit all capacity suppliers based on their marginal impact on reliability.[29] The initial capacity accreditation factors (CAFs) for 4-hour storage resources range from 64.5 percent to 78.9 percent, depending on location.[30] 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 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 11 shows simulated marginal capacity value of 4-hour storage in New York City as storage deployment increases, based on results of Potomac Economics' Resource Adequacy Tool. We considered two scenarios based on the 2030/31 capability year load forecast from the 2023 Gold Book – a "low Winter Risk" scenario in which reliability risk is concentrated in summer, and a "High Winter Risk" scenario in which we model depletion of oil unit inventories during extreme cold weather.[31]

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 High Winter Risk scenario.

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28 See our Review of the 2021-2040 Outlook study, available here.

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

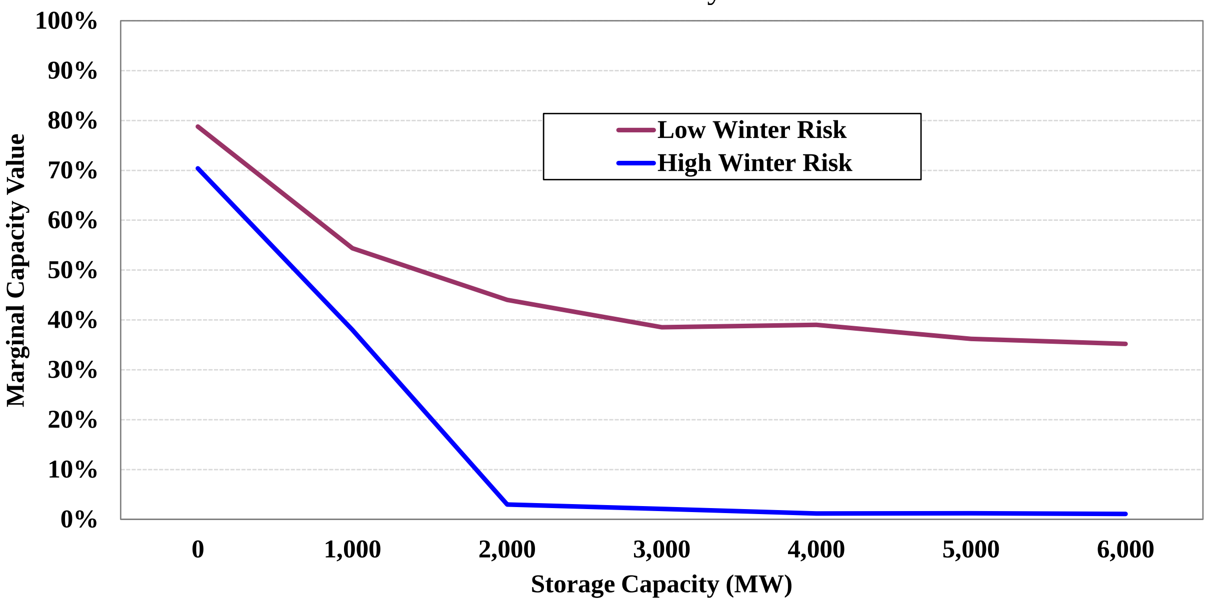
30 See NYISO's capacity accreditation webpage, available here.

31 For details, see our analysis of winter fuel security modeling in Section VIII.G and Appendix VI.E.

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 consumed in nearly all hours, causing fuel inventories to be depleted more quickly and reducing their marginal value.

Figure 11: Storage Marginal Capacity Value by Duration and Quantity

New York City



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).[32]

Conclusions on Energy Storage Incentives

The analyses in this section indicate that storage may now be profitable to develop in some locations, but this assumes that nearly 40 of revenues come from state and federal incentives. 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 far outpace efficient quantities.

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32 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.

- 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

The interconnection process consists of multiple studies.[33] After the Optional Feasibility Study (FES) and System Reliability Impact Study (SRIS), which evaluate the impacts of the individual project on system reliability and transfer capability, the project must complete the Class Year Study, which jointly evaluates the impacts of a group of projects. The Class Year Study includes:

- The System Upgrade Facilities (SUF) Study identifies network upgrades needed for the group of studied projects to comply with NYISO's Minimum Interconnection Standard

[33] This section generally applies to generators that participate in the Class Year process. Different rules apply to very small generators. For additional details on the interconnection process, see NYISO's Transmission Expansion and Interconnection Manual, available here.

(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).

- The System Deliverability Upgrade (SDU) Study identifies upgrades needed for resources to be considered 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 where they are located without violating any transmission constraints.

After the Class Year Study is completed, the developer must choose whether to pay for required upgrades to receive ERIS or CRIS rights, or to withdraw. The number of resources participating in the Class Year studies and the resulting upgrade costs have increased in recent years. Recent studies have taken approximately two years to complete. During this time, new resources seeking to interconnect that are not part of the Class Year Study must wait until it is completed and a new study begins. If the 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.

Results of Class Year 2021

The most recently completed Class Year study cycle was Class Year 2021 (CY21), which began in February 2021 and completed in January 2023.[34] Participants requested approximately 11 GW of ERIS and 10 GW of CRIS. The CY21 SUF Study initially identified over $900 million of required upgrades. Of these, $800 million were "Part 1" upgrades pertaining to direct connection of individual projects to the grid and upgrades at their own points of interconnection while $100 million were "Part 2" upgrades needed for systemwide reliability under the MIS.

Table 2 summarizes the results of the CY21 SDU Study and developers' decisions. It lists all CY21 projects that were found to be not fully deliverable in the preliminary CY21 deliverability report. Sixteen projects requesting over 4 GW of CRIS were not fully deliverable (less than 400 MW from these projects was partially deliverable). NYISO identified $1.5 billion in SDUs (preliminary estimate) for these projects. The allocation of SDUs to projects range from $468 to $2,557 per kW of UCAP. Table 2 also shows these costs when levelized over a 20-year time horizon as a percentage of the 2022/23 capacity market Net CONE in the same locality.

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34 See public NYISO notices to Class Year participants on NYISO's interconnection process page under "Notices to Market Participants", available here. See also "Class Year 2021 Facility Studies Preliminary Deliverability Analysis Draft Report", July 2022, and "Class Year 2021 Facilities Study System Upgrade Facilities (SUF) and System Deliverability Upgrade (SDU) Report", October 17, 2022. The full reports are posted in NYISO's Transmission Planning Advisory Subcommittee (TPAS) meeting materials and require a MyNYISO account with access to Critical Energy Infrastructure Information (CEII).

Table 2: Summary of CY21 Preliminary SDUs

Area	Queue #	Type	Requested CRIS MW (ICAP)	Deliverable CRIS MW (ICAP)	SDU Cost ($/kW UCAP)		Final Decision
					$ per kW UCAP	Levelized (% of Net CONE)	
Northern NY - Thousand Island	774	Solar	119	55	**1,136**	**140**	Withdraw from CY
	864	Solar	120	55	**1,125**	**139**	Accept partial CRIS (46%)
	881	Solar	100	38	**1,837**	**227**	Withdraw from CY
	882	Solar	100	55	**1,354**	**167**	Withdraw from CY
	953	Solar	125	49	**1,306**	**161**	Withdraw from CY
N.Y.C. - Staten Island	840	Storage	650	121	**795**	**50**	Accept partial CRIS (19%)
Long Island - West	958	Wind	96	0	**528**	**61**	Withdraw from CY
	959	Wind	1260	0	**528**	**61**	Withdraw from CY
Long Island - Central	925	Storage	100	0	**1,206**	**138**	Withdraw from CY
	942	Storage	60	0	**2,557**	**293**	Withdraw from CY
Long Island - East	766	Wind	880	0	**468**	**54**	Accept SDU
	987	Wind	44	0	**468**	**54**	Accept SDU
	956	Storage	110	0	**577**	**66**	Accept SDU
	965	Storage	77	0	**669**	**77**	Accept SDU
	994	Storage	90	0	**610**	**70**	Withdraw from CY
	746	Storage	150	0	**542**	**62**	Withdraw from CY

These preliminary SDUs are likely prohibitively costly for many developers. By the final round of the CY21 study, two projects accepted their partially deliverable CRIS (totaling 176 MW) without committing to further upgrades, five projects (totaling 544 MW) withdrew from the study, and the remaining projects entered the Long Island Additional SDU Study. After most of the CY21 participants dropped out, four Long Island projects totaling 1,111 MW (approximately 519 MW UCAP) accepted their final SDUs, which declined to $116 million (which is $224 per kW of UCAP and 26 percent of the Net CONE).

As Table 2 shows, deliverability upgrades affected a large portion of capacity attempting to interconnect in CY21. Even at the reduced final SDU cost of 26 percent of the Net CONE for Zone K, the SDU costs will offset a large share of the future capacity revenues for the four projects. It is unclear whether other projects that ultimately withdrew from CY21 would have accepted the SDUs at the final level. Given the scale of new capacity planned in New York, it is critical for the deliverability evaluations to be accurate and for these processes not to inefficiently inhibit new investment. We have concerns in these areas that are discussed in the remainder of this section. A more detailed assessment can be found in VI.K.

1. 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 participation 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 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, the resources in the export area may be deliverable under some conditions but not others. Load levels, generator forced outages, output levels of intermittent resources (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 system’s tightest conditions.

The findings of the deliverability study are most likely to be inaccurate when examining intermittent resources and storage, because their highly variable nature is poorly represented by the deterministic approach. These resources make up the vast majority of proposed new capacity in NYISO. Figure 12 illustrates how the deterministic study could underestimate the deliverability of renewables and storage. The blue line shows a duration curve of Long Island offshore wind output in summer peak hours, shown as a capacity factor. The black horizontal line shows the wind output that would be modeled in the deliverability test. The red vertical lines mark the critical reliability hours in Long Island in an hourly resource adequacy simulation, assuming all Long Island offshore wind projects that participated in the past two Class Year studies (3.1 GW of requested CRIS) are in service.[35]

Critical hours in Figure 12 occur more frequently when offshore wind output is low because high offshore wind output results in a capacity surplus. As a result, the deliverability study approach significantly overstates offshore wind output during critical hours. Further, over-estimating the transmission utilization by offshore wind will cause other projects to *appear* undeliverable in the hours of greatest reliability risk. This is particularly problematic for energy storage, which would be very effective in generating more during periods of low offshore wind production.

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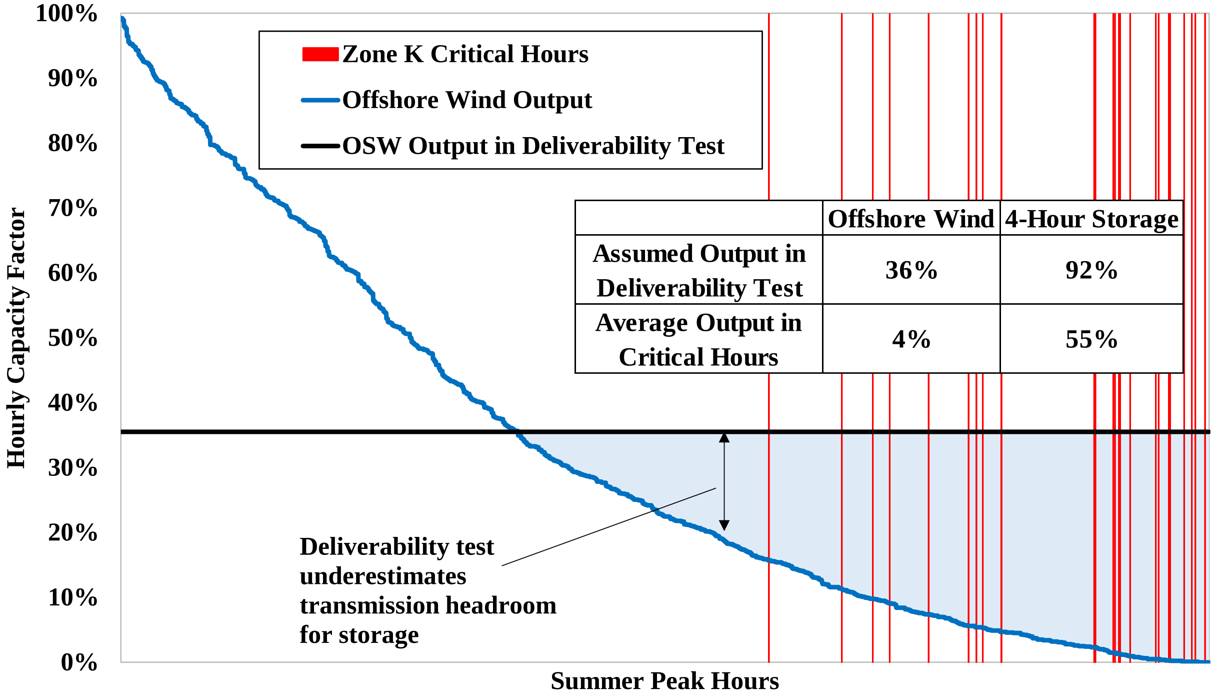
35 Critical hours are in the resource adequacy simulation are defined as hours in which load shedding occurs or hours in which storage resources were discharged prior to load shedding in the same day.

Figure 12: Long Island Offshore Wind Hourly Output and UCDF in Critical Hours



2. 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. Hence, it affected the determination of SDUs even though it subsequently exited the interconnection queue.
- *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.[36] 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 result, more capacity can be modeled in the deliverability test than can be produced in the resource adequacy model or in actual operations.

36 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.

- *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) underestimate, 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 the NYISO to increase future locational capacity requirements. Additionally, problems arise 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, which would be a substantial improvement over the deliverability framework.

3. 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.[37]

37 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

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.

4. 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.

The consequences of these problems are large and growing as recent Class Year studies have allocated large SDUs to projects seeking CRIS rights, which can be a substantial and inefficient barrier to new investment.[38] To address these concerns, we recommend:

- *Defining a comprehensive set of granular zones in the capacity market*.[39] 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 retain the economic value of those upgrades in the capacity market,[40] as will as providing a hedge against the risk of binding transmission constraints in the capacity market.[41]

Jan. 25, 2023 presentation to Management Committee "CRIS Expiration Evaluation", available here.) This may help facilitate the entry and exit but will not resolve the discriminatory nature of the deliverability rules. Holders of existing CRIS rights will value them based on their ongoing capacity profits even when it is efficient to retire, so new resources allocated costly SDUs will continue to face inefficient barriers to entry.

38 For investment in renewable resources, this effect is in addition to the other more significant economic headwinds that new investment in renewable resources have faced, which are discussed in Section III.B.1.

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

40 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.

41 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).[42] 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 has impacts 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.[43] 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.[44] In recent

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42 For more information about the CSPP, see here.

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

44 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, which concluded in 2023. Currently, NYISO is conducting a study for the New York City Offshore Wind PPTN.

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. In the most recent PPTN solicitation process, the Outlook models were also used 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.

Our reviews of recently completed planning studies provide detailed discussions of NYISO's planning models and evaluation methods.[45] NYISO's 2021 Outlook (completed in 2022) greatly improved on earlier economic planning studies. In particular, it used a capacity expansion model to develop a forecast of future resource mix changes needed to efficiently comply with state clean energy mandates. However, we have also highlighted potential areas for improvement in the planning study models.

Figure 13: Comparison of Long Island PPTN Benefits

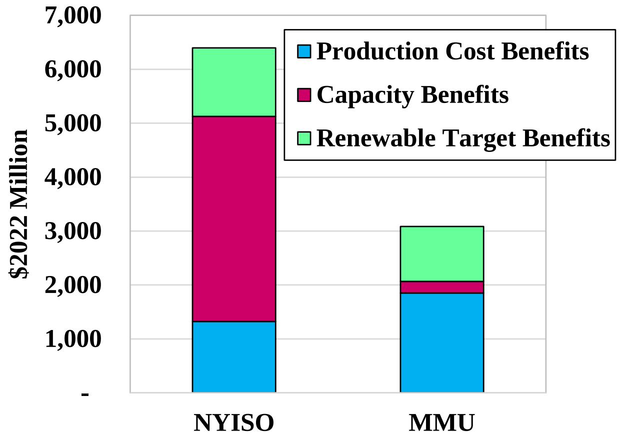

Figure 13 illustrates how improvements to modeling assumptions could have had a major impact on the evaluation of economic benefits in the recently completed Long Island PPTN solicitation.[46] It shows our calculation of the

45 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.

46 NYISO's report on the Long Island Offshore Wind Export Public Policy Transmission Plan and detailed appendices can be found in the NYISO library webpage, available here.

20-year NPV of the selected project's benefits based on: (a) several categories of annual benefit values estimated by NYISO compared to (b) assessments by the MMU of the same benefit categories as part of our review of the PPTN solicitation.[47] Economic benefits include production cost savings, avoided capacity costs due to improved transmission into Long Island, and cost savings of renewable investments needed to meet New York's public policy goals.

Our assessment found the selected project's economic benefits to be about 50 percent lower than NYISO's estimates. The largest sources of difference were:

- *Capacity investment savings*: NYISO's study found that the project would avoid the need to build approximately 2 GW of dispatchable emissions-free resource (DEFR) capacity on Long Island and allow that capacity to be built at lower cost in western New York instead. NYISO estimated the project's impact on the Long Island LCR using an incomplete approach that did not consider the potential for other constraints between western New York and Long Island to become bottlenecked. Our assessment found that constraints not addressed by the project (most notably, the UPNY-CONED constraint between zones G and H) would limit the ability to shift capacity requirements upstate, resulting in much lower capacity benefits without also upgrading those constraints.
- *Production cost savings*: NYISO estimated production cost savings from the selected project using GE MAPS. NYISO's current approach does not thoroughly consider how new transmission would affect the need to commit inflexible generation to provide reserves. It also does not model transmission outages that cause transmission capability to be limited in actual operations. As a result, NYISO's approach tends to underestimate production cost benefits of transmission projects.

The example of the Long Island PPTN demonstrates that using more realistic modeling assumptions can have a first order impact on the estimated economic benefits of a project. Improvements to modeling assumptions and techniques will help ensure that future transmission needs are assessed accurately and that solicitations select the most efficient candidate projects.

We have previously made recommendations to improve the quality of assumptions and modeling techniques used in the Outlook and other planning studies.[48] NYISO made the following enhancements in the ongoing 2023 Outlook, which will help to address our recommendations:

- Inclusion of battery storage options with multiple durations (4-hour and 8-hour);
- Modeling representative chronological days in the capacity expansion model to more realistically capture the benefits of energy storage; and
- Modeling estimated costs of a new or repowered dispatchable hydrogen-burning capacity instead of generic dispatchable emissions free resource (DEFR) costs in the "State Scenario" capacity expansion model.

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47 The NPV of benefits in this figure is larger than the discounted value reported in NYISO's Long Island PPTN report because we corrected an issue with discounting of benefits by NYISO.

48 See the Section V of our comments on the Long Island PPTN study, available here.

We have also recommended the following enhancements, which have not been addressed in the ongoing 2023 Outlook study. These issues should be considered in future planning studies:

- 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;
- 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;
- Improve the siting and dispatch pattern of storage investments in MAPS to more realistically minimize renewable curtailment based on market incentives; 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:[49]

- <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.
- <u>Implied Net REC</u> – 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

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

energy and capacity benefits, divided by the incremental reduction in annual renewable curtailment it provides ("renewable deliverability impact").[50]

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:[51]

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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50 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.

51 See Recommendation 2022-3 in Section XII.

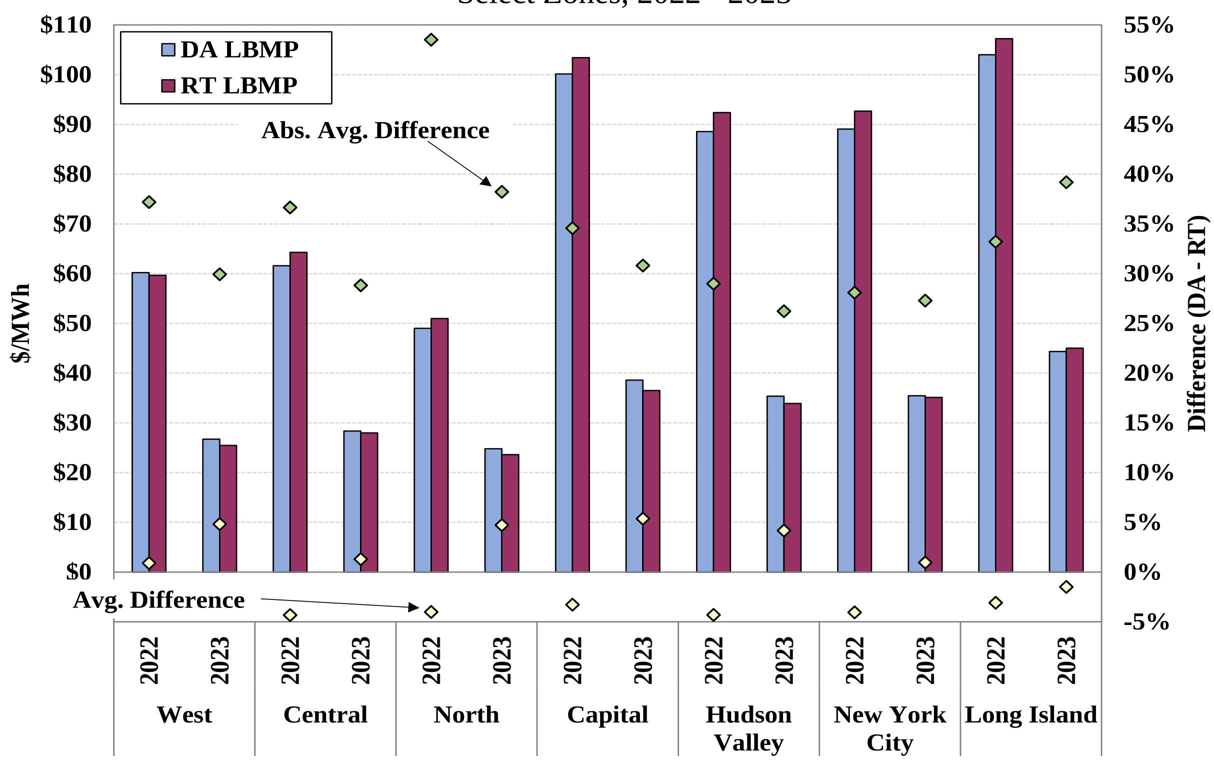
V. DAY-AHEAD MARKET PERFORMANCE

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 table also reports the average absolute value of the difference between hourly day-ahead and real-time prices.[52] These statistics are shown on an annual basis.

Figure 14: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2022 - 2023



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

Day-ahead prices in 2023 were higher than real-time prices in all regions except for Long Island. It is expected in a competitive market that day-ahead prices will maintain a small premium to real-time. Real-time prices tend to be higher than day-ahead prices during volatile periods. In 2023, we observed less real-time volatility due to mild weather conditions across the year, persistently low gas prices, and fewer transmission outages along the Central East Interface. September was the only month when real-time price premiums were widespread because of high summer loads and generator outages and deratings.

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. The combination of these factors leads to volatile congestion pricing at several transmission bottlenecks in northern New York.

B. Day-Ahead Load Scheduling

Under-scheduling load generally leads to lower day-ahead prices, while over-scheduling can raise day-ahead prices above those in real-time. Table 3 shows the average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2022 and 2024 for several regions.[53]

Overall, net scheduled load in the day-ahead market was approximately 97 percent of actual NYCA load during daily peak load hours in 2023, consistent with 2022. 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.

[53] Figure A-35 to Figure A-42 in the Appendix also show these quantities on a monthly basis.

Table 3: Day-Ahead Load Scheduling versus Actual Load
By Region, During Daily Peak Load Hours, 2022 – 2023

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2022	98.7%	0.0%	-5.7%	11.4%			104.3%
	2023	98.3%	0.1%	-12.5%	7.7%			93.7%
Central NY	2022	95.1%	0.0%	-5.6%	5.8%			95.3%
	2023	98.3%	0.0%	-6.0%	9.1%			101.4%
North	2022	88.5%	0.2%	-11.7%	10.7%			87.6%
	2023	76.9%	20.0%	-18.1%	6.9%			85.7%
Capital	2022	94.4%	0.0%	-5.3%	6.9%			96.0%
	2023	99.1%	0.0%	-9.0%	8.1%			98.2%
Lower Hudson	2022	72.7%	23.6%	-13.7%	12.6%			95.1%
	2023	73.2%	25.0%	-22.7%	15.8%			91.2%
New York City	2022	64.6%	32.9%	-1.4%	2.8%			99.0%
	2023	63.6%	35.0%	-2.2%	4.2%			100.6%
Long Island	2022	98.0%	0.0%	-1.7%	7.9%			104.2%
	2023	98.8%	0.0%	-3.2%	10.8%			106.3%
NYCA	2022	82.9%	13.6%	-4.9%	6.7%	-2.5%	0.7%	96.6%
	2023	83.3%	15.2%	-7.7%	8.3%	-3.6%	1.0%	96.5%

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 Public Policy transmission 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 fell by roughly 14 percent from 2021 to 2023.

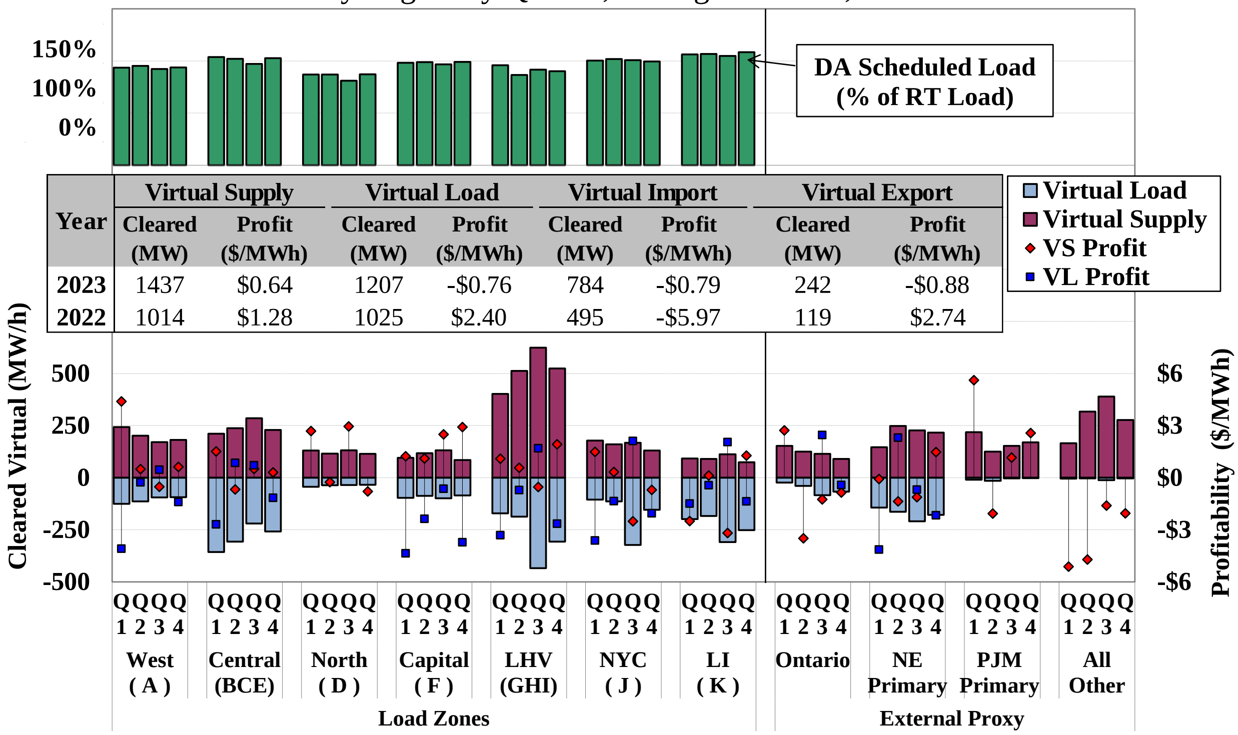
New York City and Long Island both saw increases in the percentage of net load scheduled day-ahead from 2022. Higher day-ahead net load scheduling generally helps increase commitment of resources in these areas. In Long Island, day-ahead commitments are necessary to ensure that sufficient baseload gas-fired capacity is available in the event of unexpected volatility in real-time. In New York City, day-ahead net scheduled load rose to average 101 percent in 2023, which was likely driven by expectations of increased price volatility following exit 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 15 summarizes virtual trading by location in 2023, including internal zones and external interfaces.[54]

Figure 15: Virtual Trading Activity

by Region by Quarter, During All Hours, 2023



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)
2023	1437	$0.64	1207	-$0.76	784	-$0.79	242	-$0.88
2022	1014	$1.28	1025	$2.40	495	-$5.97	119	$2.74

Virtual trading patterns were mostly consistent from 2022 to 2023 but certain locations were markedly different from years past. Virtual supply increased substantially at the NE primary and Quebec interfaces, the West Zone, and LHV. However, virtual load fell in the West Zone and increased at LHV. The changes in scheduling patterns coincide with increases in transfer capability related to the Western NY and AC Public Policy transmission projects.

The profits and losses of virtual load and supply have varied over time, reflecting the difficulty of predicting volatile real-time prices. In 2022, virtual traders netted a gross profit of approximately $20 million, but that fell to about $7 million in losses in 2023. Virtual profits at internal zones in 2023 totaled ~$100,000, while virtual trading at interfaces lost $7 million. The overall average rate of gross virtual profitability remained relatively close to zero at -$0.22 per MWh. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market, so virtual losses are unlikely to persist for a significant period of time.

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54 See Figure A-44 in the Appendix for a detailed description of the chart.

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 to meet expected conditions on the following day, and the real-time market should dispatch the available resources efficiently. Prices should be consistent with the costs of satisfying demand while maintaining reliability. Efficient real-time prices encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable. During shortages, the real-time prices should reflect the value of foregone supply and incent suppliers to help maintain reliability. System operations is also important because it can have large effects on wholesale market efficiency and costs.

We evaluate six aspects of market operations, focusing on the efficiency of scheduling and whether prices provide appropriate incentives, particularly during tight operating conditions:

- Market Performance under Shortage Conditions
- Real-Time Pricing of Gas Turbines Bidding Mult-Hour Minimum Run Time
- Operation of Duct-Firing Capacity
- Performance of Intermittent Power Resources during Curtailment Events
- Supplemental Commitment for Reliability
- Uplift from Bid Production Cost Guarantee (BPCG) payments

This section discusses several recommendations that we have made to enhance pricing and performance incentives in the day-ahead and real-time markets, while Section XII provides a comprehensive list of our recommendations.

A. Market Performance under Shortage Conditions

Prices during shortages are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the system's need for energy and ancillary services. Efficient shortage prices reward suppliers and demand response resources for responding to shortages. This ultimately improves the resource mix by shifting revenues from the capacity market into the energy market in a manner that better reflects the resources' performance. In this subsection, we evaluate the real-time market operations and prices when the system is in the following two types of shortage conditions:[55]

[55] Emergency demand response deployments are similar to shortage conditions because they generally occur when the NYISO forecasts a reserve deficiency. See Appendix Sections V.K and VIII.C for our evaluations of demand response deployments in 2023.

- *Operating reserve and regulation shortages* – These occur when the market schedules less than the required amount of ancillary services. Co-optimizing energy and ancillary services causes the foregone value of the ancillary services to be reflected in LBMPs.
- *Transmission shortages* – These occur when modeled power flows exceed the limit of a transmission constraint. LBMPs at affected locations are set by the Graduated Transmission Demand Curve (GTDC) in most cases during transmission shortages.

1. Operating Reserve and Regulation Shortages

Operating reserve and regulation shortages became less frequent from 2022 to 2023, consistent with the decline in high load periods. Regulation shortages continued to be the most frequent type of ancillary services shortage in 2023, but they occurred in just 3 percent of intervals, down from the 10 percent in 2022. Operating reserve shortages were relatively infrequent in 2023, occurring in 0.6 percent of intervals. Shortages of regulation and operating reserves collectively increased average LBMPs by 4 to 5 percent in 2023.[56] Thus, ancillary services shortages have a significant impact on investment signals, shifting incentives toward flexible generation.

During operating reserve shortages, real-time prices should reflect the foregone value of reserves and provide 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 New England.[57] Figure 16 examines the shortage pricing incentives provided by NYISO compared to its neighbors, which both have shortage pricing in the energy market that is supplemented by "pay-for-performance" settlements that are additive to the shortage pricing in the energy market.[58] It 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 reach near $1,000 per MWh, compared to more than $4500 per MWh in ISO-NE. ISO-NE's shortage pricing will rise to roughly $6500 in June 2024 when it raises its Performance Payment Rate from $3,500 to $5,455 per MWh.[59]

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56 See Section V.J in the Appendix for this analysis.

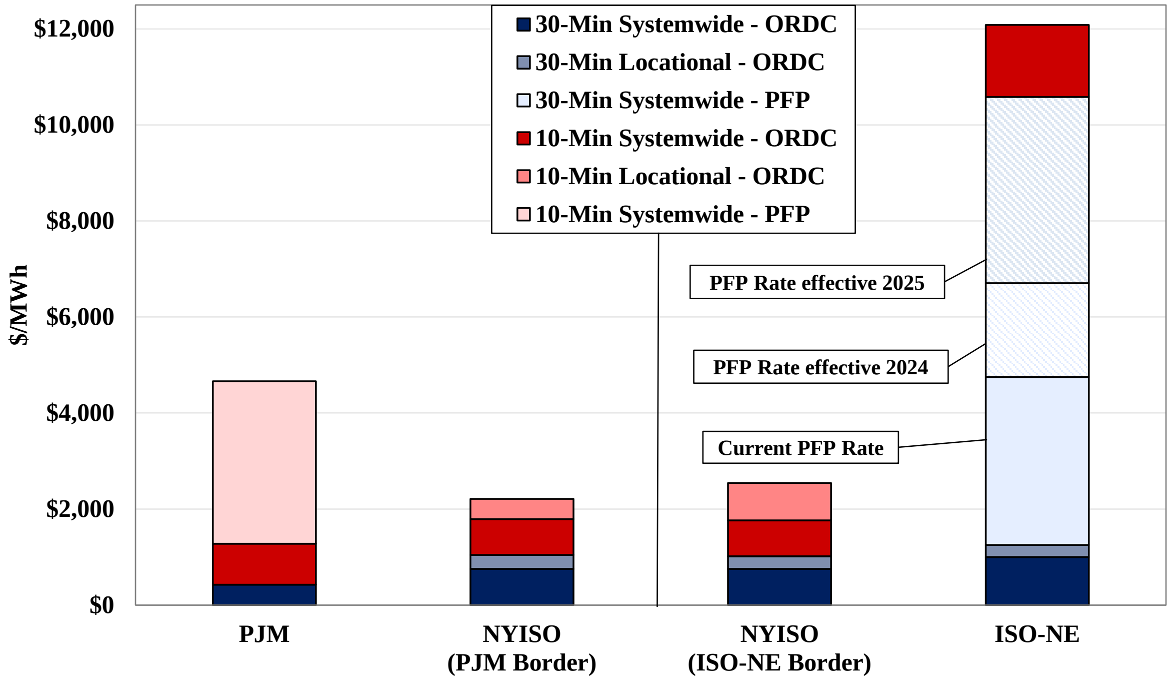
57 ISO New England has Pay For Performance ("PFP") rules, and PJM has Capacity Performance ("CP") rules. These rules provide incentives similar to shortage pricing through adjustments to capacity payments.

58 See Figure A-96 in the Appendix for description of this chart.

59 See ISO New England Tariff Section III.13.7.2.

- During deep shortages of multiple 30-minute and 10-minute reserve requirements, NYISO invokes statewide shortage pricing levels that can exceed $2,000/MWh under very severe conditions. This is much lower than the current total shortage pricing in PJM of almost $4700 per MWh and roughly $7500 per MWh in ISO-NE by June 2024.

Figure 16: Shortage Pricing in NYISO vs. Neighboring Markets



Hence, 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 disparity will likely undermine reliability in New York or require NYISO operators to engage in out-of-market actions to maintain reliability.

ORDC Price Levels Compared to the Reliability Value of Reserves

In addition to comparing NYISO's shortage pricing to its neighbors, we also evaluate how well its shortage pricing reflect the reliability risks that arise when the system is short of reserves. Shortage pricing is determined by an RTO's ORDC for each class of reserves, which ideally should indicate the marginal reliability value of the reserves. This value is based on the value being able to serve the load, referred to as the Value of Lost Load (VOLL). As reserve levels fall the risk of load shedding increases, so the marginal value of reserves can be estimated as:

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

Based on studies of the value of reliability, an estimated VOLL of $30,000 per MWh is reasonable for NYISO loads.[60] The slope of an efficient ORDC depends on the rate at which the

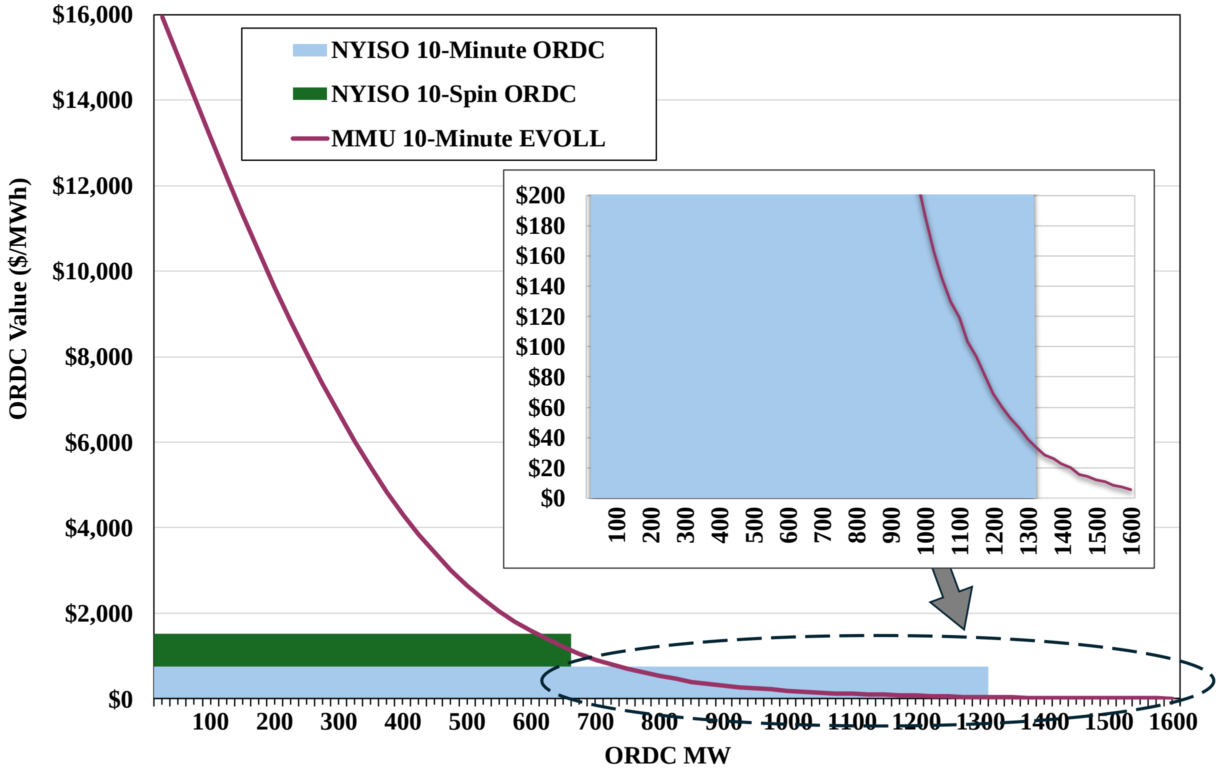
[60] See Section V.I in the Appendix for the mentioned studies.

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 estimate the relationship between the availability of 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 (or collectively "unexpected losses of net supply").[61]

Figure 17 illustrates our estimates of the EVOLL curve for NYCA-wide 10-minute reserve requirements compared 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 10-minute reserves.

Figure 17: Comparison of MMU Economic ORDC to the Current 10-Minute ORDCs

NYCA Wide 10-Minute Reserves



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

61 See Section V.I in the Appendix for the simulation methodology in more details.

A comparable analysis of the 30-minute ORDC is discussed in Section V.I. of the Appendix. 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 of 30-minute reserves when they are exhausted stands at roughly $2,800 per MWh, nearly four times of the $750 per MWh set by the current ORDC.

Finally, the MMU-estimated curves extend beyond the existing requirements of 1310 MW for 10-minute reserves and 2620 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.[62]

ORDC Price Levels – Conclusions

We recommend the NYISO revise the current ORDC curves to accomplish two objectives, to:

- Schedule resources as necessary to satisfy reliability criteria without resorting to OOM actions – The current ORDCs may prove inadequate since PJM and ISO New England have adopted unreasonably strong shortage pricing incentives.
- Achieve better alignment with the estimated reliability value of reserves – The ORDCs for statewide requirements are inadequate during deep shortages of 10-minute and 30-minute operating reserves when reliability risks are relatively high.

This recommendation is high priority because the demand for resources to respond to emergency conditions in real-time will become increasingly important.[63] Large-scale entry of intermittent renewables is expected to increase net load forecast uncertainty and, consequently, the estimated reliability value of reserves. Implementing this recommendation will improve incentives for generation and load flexibility. The costs associated with increasing the operating reserve demand curves would be offset by a corresponding reduction in capacity market demand curves.

2. Transmission Shortages

It is crucial for the market to establish efficient prices during transmission shortages that accurately reflect the severity of shortages and properly value the effects of transmission bottlenecks across the system. In 2023, transmission shortages occurred in 5 percent of all 5-minute market intervals, although this was down significantly from 13 percent in 2022 because of milder system conditions. Transmission shortages play a significant role in setting prices that reflect the effects of transmission bottlenecks across the system.

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62 Recommendation 2021-1. Also see the presentation at ICAPWG/MIWG, "*Balancing Intermittency: Percentiles and Shortage Pricing Curves"*, March 4, 2024.

63 Recommendation 2017-2.

Most transmission shortages are minor and short-lived, posing no significant threat to security or reliability. This is because the NYISO uses a Constraint Reliability Margin (CRM) of 10 to 100 MW that builds in a buffer between modeled flows and the applicable transfer limit for each facility to ensure that transient differences between schedules and actual output do not lead to violations of transmission security criteria.[64] The NYISO uses a Graduated Transmission Demand Curve (GTDC) to set prices that reflect the severity of system conditions, setting moderately high prices during slight shortages that escalate with the magnitude of the shortage.[65]

In mid-November, the NYISO implemented *Constraint Specific Transmission Shortage Pricing*, which aligns the MW steps on the GTDC with the CRM for each facility.[66] This should lead to a better correspondence between shadow prices and the severity of transmission congestion. Additionally, the majority of internal facilities previously assigned a zero-value CRM are now equipped with a new 2-step GTDC with a 5-MW CRM. This adjustment aims to further reduce the occurrences of constraint relaxation, which occurred in 4 to 5 percent of all transmission shortages over the past two years. Given its recent implementation, we have not included an evaluation of the new pricing logic in this report, but plan to do so in future reports.

However, we have identified an issue that undermines pricing by causing the market software to not recognize real-time transmission shortages. This is caused by NYISO's "offline GT pricing," which treats an offline GT being dispatchable in five minutes even though it is offline and cannot start in 5 minutes. This inefficiently depresses constraint shadow prices and associated congestion when constraints are violated. It also leads to large differences between modeled flows and actual flows, limiting the ability of the real-time market models to maintain transmission security in areas that rely more on peaking units such as Long Island. To account for these differences, NYISO employs relatively large CRMs on key constraints affected by offline GT pricing, such as the 345 kV lines from upstate New York to Long Island.

Figure 18 shows our analysis of the 345 kV and 138 kV facilities on Long Island.[67] The blue points indicate the size of the transmission constraint violation calculated by the market software, which assumes that offline GTs can produce output, while the red points indicate what the constraint violation is recognizing that the offline GTs do not produce output.

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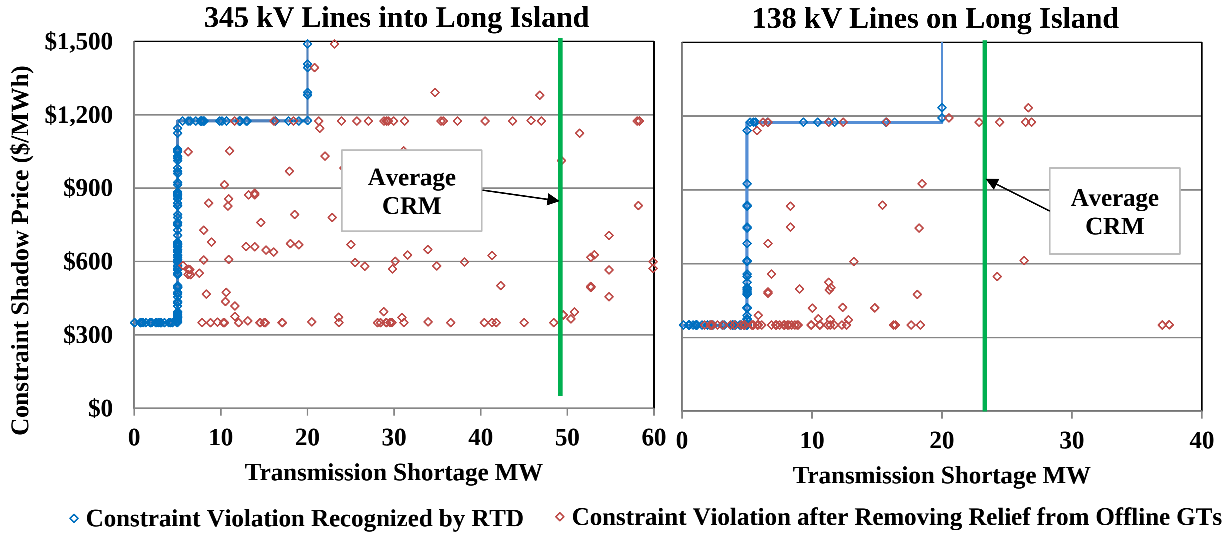
[64] A default CRM value of 10 MW is used for 69 kV and 115 kV constraints, while a default CRM value of 20 MW is used for most facilities at higher voltage levels. NYISO may adjust the CRM for an individual facility based on operating experience as necessary to maintain security.

[65] 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 18.

[66] 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.

[67] See Figure A-101 in the Appendix for description of the chart.

Figure 18: Transmission Constraint Shadow Prices and Violations
With and Without "Relief" from Offline GTs, 2023



Long Island has most GTs that are treated as capable of responding to a 5-minute dispatch instruction while offline. The use of offline GT pricing compels NYISO to use high CRMs that constrain transmission flows at artificially low levels in areas that rely more on peaking units such as Long Island. This leads to unnecessary generation dispatch and inflated production costs during most periods of congestion. Given these inefficient effects and the fact that it serves no useful purpose, we recommend the NYISO eliminate offline fast-start pricing.[68]

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

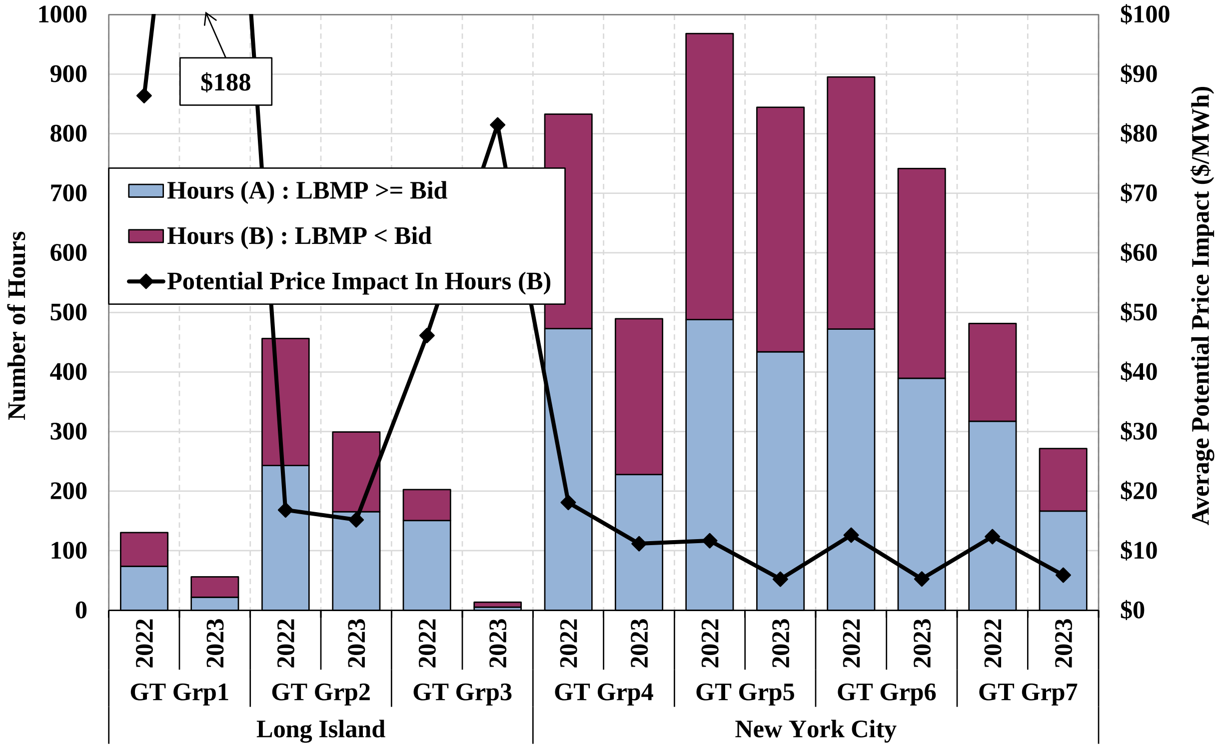
Gas turbines run more frequently under tight conditions when it is particularly important to establish efficient real-time prices that incentivize flexible resources. The existing fast-start pricing rules include the as-offered deployment costs of fast-start units in real-time prices, including start-up,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

However, fast-start units with minimum run time offers exceeding one hour are not included in fast-start pricing. Currently, the real-time market software (including RTC and RTD) and settlement rules ignore the minimum run time offers of these units, deeming them to have a one-hour minimum run time when they submit economic real-time offers. Even though these units treated the same as a unit that submitted a one-hour minimum run time, they are not eligible to set prices. This prevents LBMPs from accurately reflecting the cost of maintaining reliability when these gas turbines are needed.

68 See Recommendation 2020-2.

Figure 19 evaluates prices during economic commitments of gas turbines offering multi-hour minimum run times in the real-time market in 2022 and 2023.[69] Gas turbines in New York City and Long Island are combined into seven groups based on their electric connection to the grid.

Figure 19: Prices During Commitments of GTs Offering Multi-Hour Min Run Times
2022 - 2023



Economic starts were more frequent among the four GT groups in New York City, ranging from approximately 300 to 1000 hours each year over the past two years. However, in 46 percent of these hours, LBMPs fell below GT costs. This disparity was largely due to these GTs not being eligible to set prices when they offered multi-hour minimum run times. We estimate that if these GTs were allowed to set prices, the average LBMP during these hours would have been up to $5-$18 per MWh higher at locations in New York City.

Although the three GT groups on Long Island had fewer economic starts annually, the GTs' costs exceeded LBMPs in 43 percent of start hours. The estimated average potential price impact was considerably higher at these locations on Long Island, with potential increases ranging from $15 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 prices would have been affected in broader areas depending on congestion patterns.

69 Economic GT commitments include GT start-ups made economically by RTC, RTD, and RTD-CAM, excluding self-schedules. See Figure A-79 in the Appendix for more details of this analysis.

Given these inconsistencies between real-time prices and scheduling, we recommend the 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 the value of the 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.[70]

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.[71] However, some duct-firing capacity is not always capable of following a five-minute dispatch signal.

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.[72] 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 offering a service they are frequently not physically capable of providing.

Offers to Sell Duct-Firing Capacity that Cannot Perform Reliably

We estimate that, in 2023, on average:

- 100 MW was offered but not capable of following 5-minute ramping instructions;
- 142 MW was scheduled for but not capable of providing 10-minute reserves; and
- 12 MW was scheduled for but not capable of providing regulation.

These offers may present challenges in real-time operations especially when the duct-firing capacity becomes more valuable 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:

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70 See Recommendation 2023-2.

71 See Table A-9 in the Appendix.

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

- Reduced energy offers – 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 way. We estimate that an average of 49 MW of duct-firing capacity was unavailable for this reason in 2023.
- 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.[73]
- 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 93 MW of available 10 and 30-minute reserves in non-duct ranges were not offered for this reason in 2023.

We recommend NYISO consider alternative ways to schedule this capacity that takes into account the physical limitations of duct burners.[74] 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

The NYISO proposed several changes in the *Improve Duct-Firing Modeling Project* to address the issues discussed above.[75] 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 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

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73 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.

74 See Recommendation 2020-1.

75 See *"Improve Duct-Firing Modeling: Market Design Update",* ICAPWG/MIWG, February 29, 2024

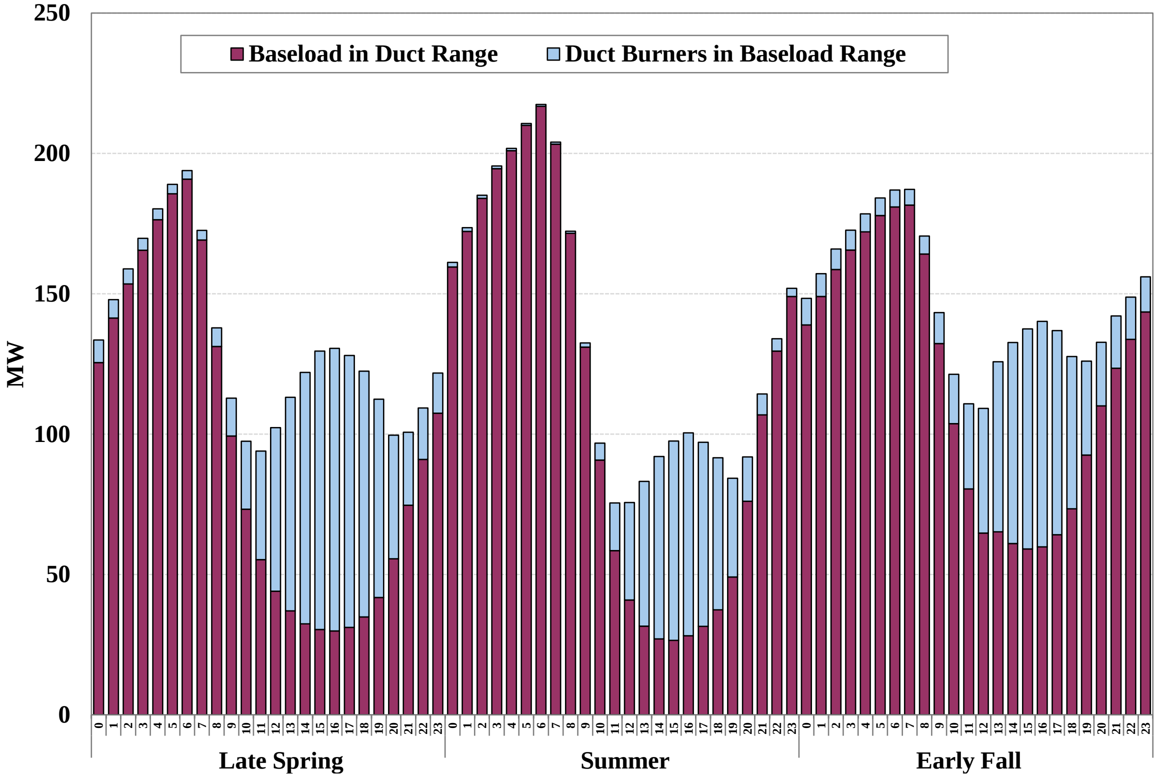
administrative parameters that can only be modified after consultation with the NYISO even though the physical capabilities of these units fluctuate with ambient conditions.[76]

Although we support the core modeling changes proposed by the 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.[77] Since duct firing ranges are generally the last block of output, the output level where duct burners need to fire varies daily and hourly.

Figure 20 analyzes 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.[78] 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.

Figure 20: Incorrect Designation of Duct-Fired CCs from Administrative Ramp Rates

Ambient-adjusted Capability, Summer Capability Period



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

[77] See Figure A-82.

[78] See Section V.B in the Appendix for the methodology of this analysis.

Baseload capacity would be incorrectly designated as duct burner if the forecasted conditions used to set the administrative ramp rates were warmer than actual conditions, while duct burner capacity would be incorrectly designated as 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 the 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).[79] 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.

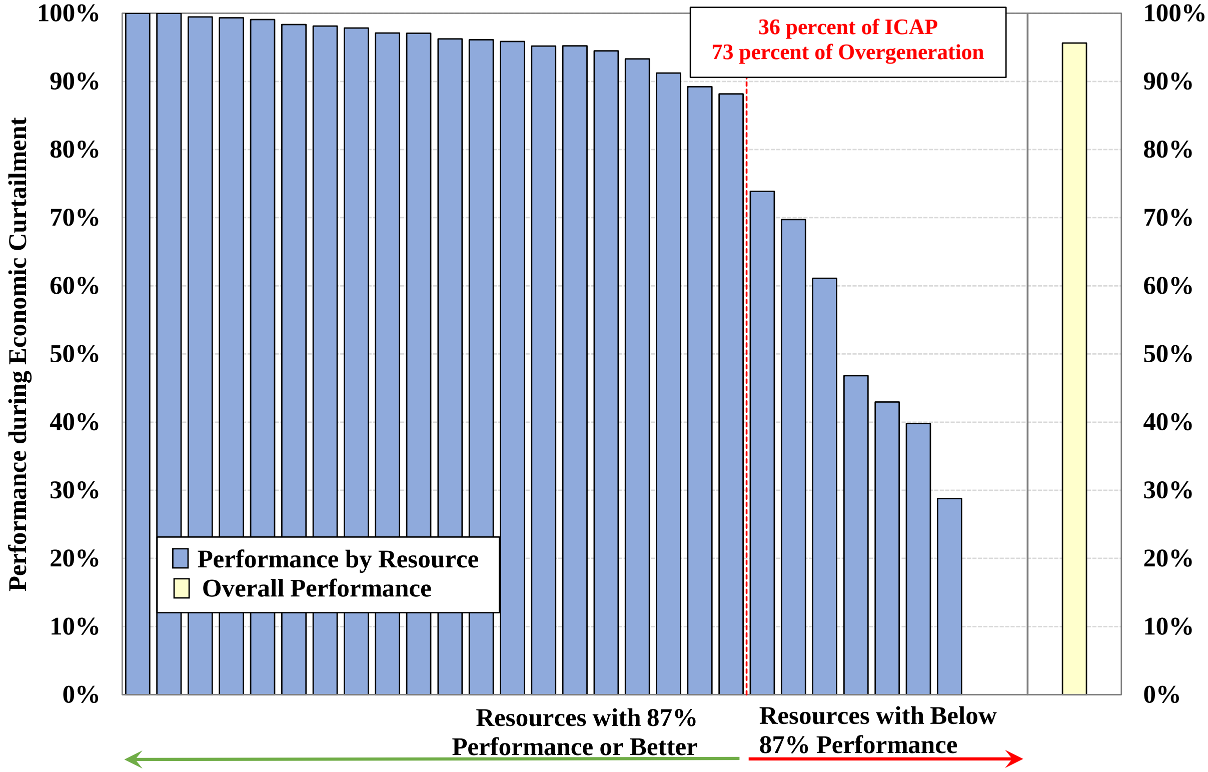
Figure 21 displays the average performance of each IPR facility in 2023 in adhering to Output Limits (excluding facilities with fewer than 10 intervals of curtailment), while the aggregate performance of all IPRs is indicated by the yellow column.[80] Average performance is calculated for each resource 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.

Overall performance during economic curtailments averaged 96 percent. Most IPRs (including 64 percent of total capacity) respond at 88 percent performance or better to Output Limits from the NYISO. However, a minority of IPRs (36 percent) exhibited poor performance, which accounted for 73 percent of all overgeneration during economic curtailments in 2023. 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.

[79] 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.

[80] For a detailed description of this figure, see Appendix Section V.C.

Figure 21: Performance of IPRs during Economic Curtailment

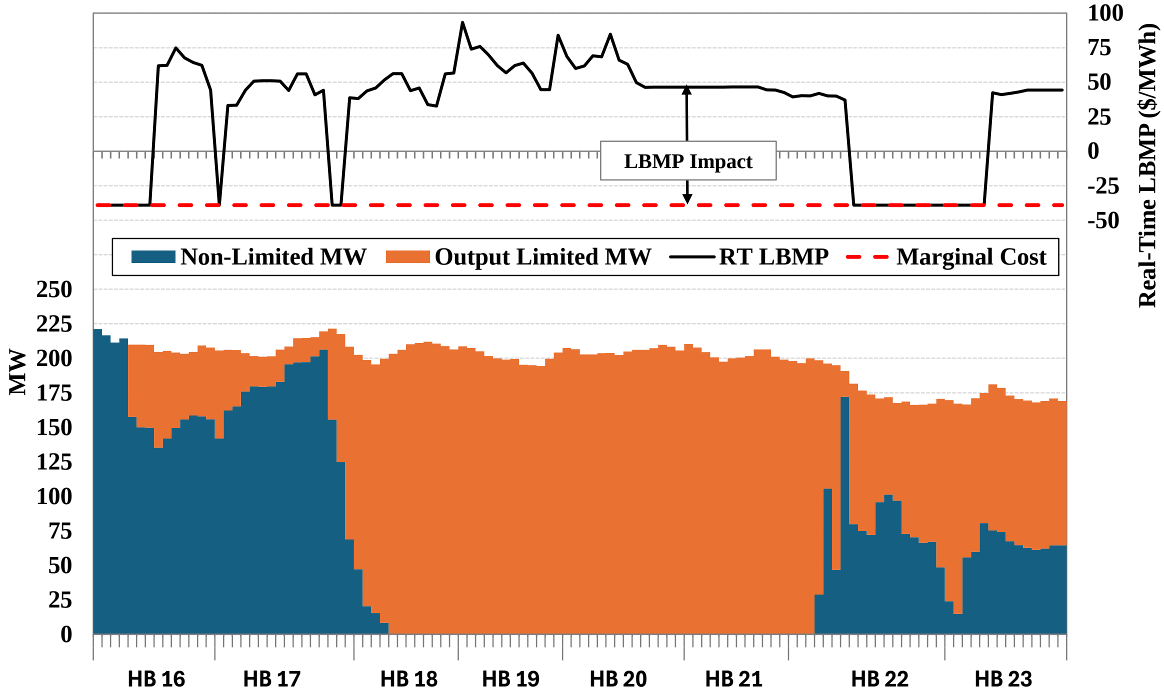


When an IPR does not follow curtailment instructions, it is frequently caused by connectivity issues between the generating facility and automated and/or remote operating systems. During these events, the market model will first issue an Output Limit, but it becomes apparent that the IPR is not following 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 recent 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.[81] To address these concerns, we recommend changes to the overgeneration charge to incent IPRs to follow dispatch instructions.[82]

81 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 ERT = 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.

82 See Recommendation 2023-3.

E. Supplemental Commitment for Reliability

Supplemental commitment occurs when a unit is not committed economically but is needed for local or systemwide reliability. There are several types of supplemental commitment:

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

Similarly, the NYISO and local transmission owners sometimes dispatch generators out-of-merit (OOM) to: (a) manage constraints of high voltage transmission facilities that are not fully represented in the market model; or (b) maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the supply available in real-time, while OOM dispatch increases production from capacity that is normally uneconomic and displaces output from economic capacity. These OOM actions highlight a gap in the market that necessitates the OOM action to obtain a reliability service that is not provided by the market. The OOM actions also 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 commitment and OOM dispatch 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 the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2022 and 2023.[83] In 2023, approximately 440 MW of capacity was committed on average for reliability, marking a 26 percent decrease from 2022. The decline was largely attributable to a 37 percent reduction in New York City. LRR commitments in New York City plummeted by 91 percent from the previous year primarily because "NOx bubble" commitments were eliminated in New York City load pockets following the retirement of associated oil-fired peaking units.[84]

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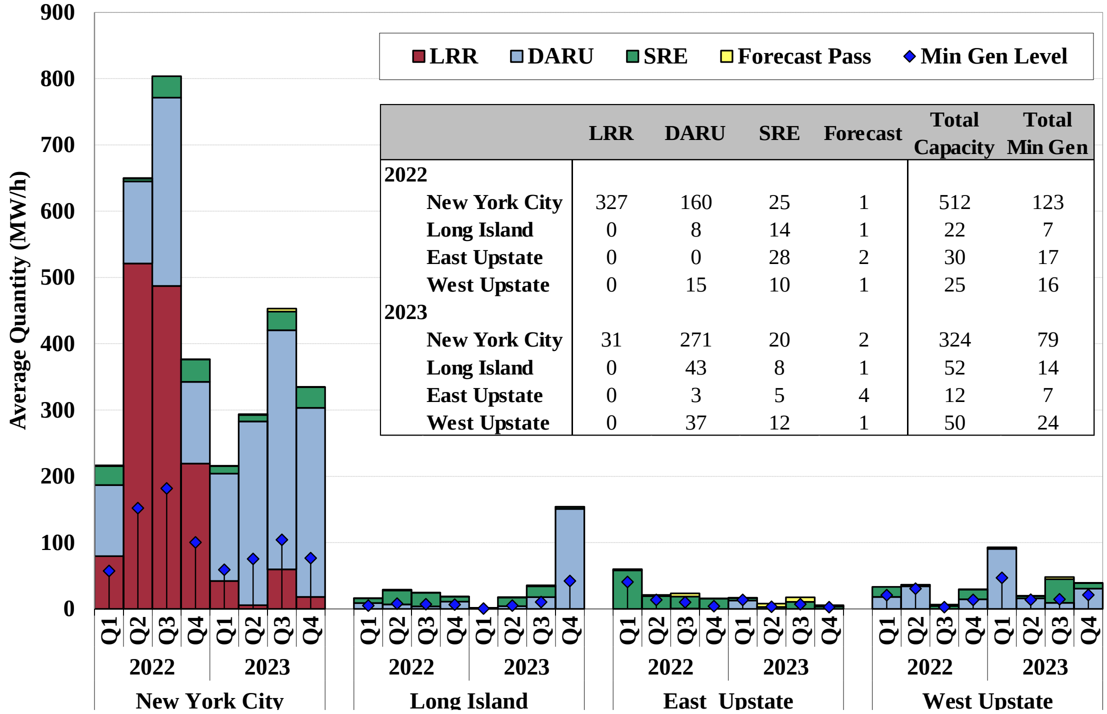
83 See Section V.L in the Appendix for a description of the figure.

84 In New York City, the NY DEC NOx Bubble program mandates that the plants within a single portfolio meet overall emission standards collectively, rather than individually. This approach allows some generators to

Figure 23: Supplemental Commitment for Reliability in New York
By Category and Region, 2022-2023



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2022						
New York City	327	160	25	1	512	123
Long Island	0	8	14	1	22	7
East Upstate	0	0	28	2	30	17
West Upstate	0	15	10	1	25	16
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

Additionally, lower gas prices, decreased NOx allowance prices, and retirements of 800 MW of peaking capacity led to more frequent economic commitments of New York City generators that also helped satisfy local reliability needs. The local TO made more frequent DARU commitments in 2023, which increased nearly 70 percent from 2022, further reducing the need for LRR commitments. These DARU commitments are evaluated further below.

In Long Island, reliability commitments occurred more frequently in 2023, mainly in the fourth quarter when steam turbines were needed to manage 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 two days in 2023 versus 27 such days in 2022. These commitments highlight that the current 30-minute reserve requirement for Long Island is inadequate to maintain reliability. 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 incentives for suppliers. 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.[85]

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emit NOx above specified levels, provided that the average emissions from all generators within the "bubble" remain below the limit. For example, if high-emitting oil-fired GTs are running, one or more low-emitting STs within the same "bubble" must be running to ensure compliance with the average emission limit.

85 See Recommendation 2021-2.

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.[86] The NYISO plans to implement this recommendation along with the Dynamic Reserves project.[87]

In upstate regions, OOM commitments became more frequent in 2023 primarily to satisfy N-1-1 criteria in the North Country load pockets on 143 days (compared to 67 such days in 2022). As in New York City and Long Island, modeling these local reserve requirements would improve market efficiency and establish proper market signals for future investments.

2. DARU Commitment in New York City

Figure 24 further examines the reasons for DARU commitments made by the local TO in New York City, which accounted for most reliability commitments in 2023.[88] For capacity that was not otherwise "Economic" in day-ahead market, the figure summarizes the quantities of DARU commitments that we "Verified" were needed to satisfy known N-1-1-0 constraints based on day-ahead forecasted conditions versus commitments that were "Unverified" in our assessment. It is important to evaluate OOM commitments to ensure that they are necessary for reliability and cost-effective and to identify potential gaps in the NYISO market design.[89]

In 2023, DARU commitments to satisfy N-1-1-0 reliability needs in load pockets of New York City rose significantly from the prior year. An average of 405 MW were DARU-committed for New York City load pockets on 225 days. Our evaluation of these commitments reveals that:

- 32 percent of these commitments were deemed economic in the day-ahead market scheduling software – These are excluded from the "DARU" category in Figure 23.
- 45 percent was verified to be needed to satisfy specific reliability requirements by the MMU based on information on system conditions available in the day-ahead market related to forecasted load, the status of generation and transmission, and contingencies.
- 23 percent could not be verified by the MMU. Several factors may account for some of these commitments: (a) DARU requests are typically made at least two days in advance for consecutive days, and forecasts are often less accurate when the DARUs were requested; and (b) the local TO may have requirements that are not known by the MMU.

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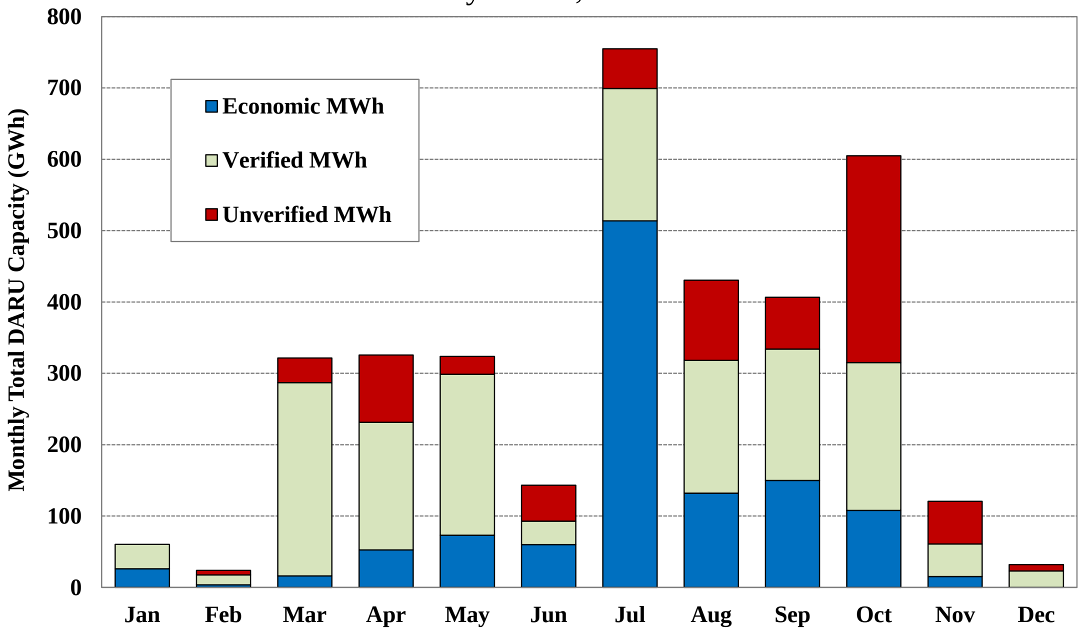
[86] See Recommendation 2019-1.

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

[88] See Figure A-109 in the Appendix for a description of the figure.

[89] 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.

Figure 24: DARU Commitment by the Local TO in New York City
By Month, 2023



Despite the surge in DARU requests from the local TO, the overall amount of capacity committed in the day-ahead market for New York City reliability, which was not otherwise economic, actually *fell* from the previous year, as shown in Figure 23. This decline can be attributed to various factors. First, the increased DARU commitments were partially offset by reduced LRR commitments, which are made in the day-ahead market to address the same underlying needs. Second, factors such as gas price patterns, lower NOx allowance prices, and the elimination of NOx bubble commitments reduced the need for supplemental commitments. Nonetheless, it is important to recognize that out-of-market reliability commitments significantly influence resource scheduling and pricing. Therefore, it would be beneficial to reflect the underlying N-1-1-0 requirements as local reserve requirements.[90]

3. Forecast Pass Commitment

Forecast pass commitments were infrequent, and the amount of committed capacity was small. Nonetheless, we identified two issues in this process. First, we found that some 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 recognized as quick-start by the software.[91] 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 significantly lower than the forecasted load and reserve needs on most days.[92]

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90 See Recommendation 2017-1.

91 See Section V.E in the Appendix for more information about this analysis.

92 See Figure A-107 in the Appendix for more information about this analysis.

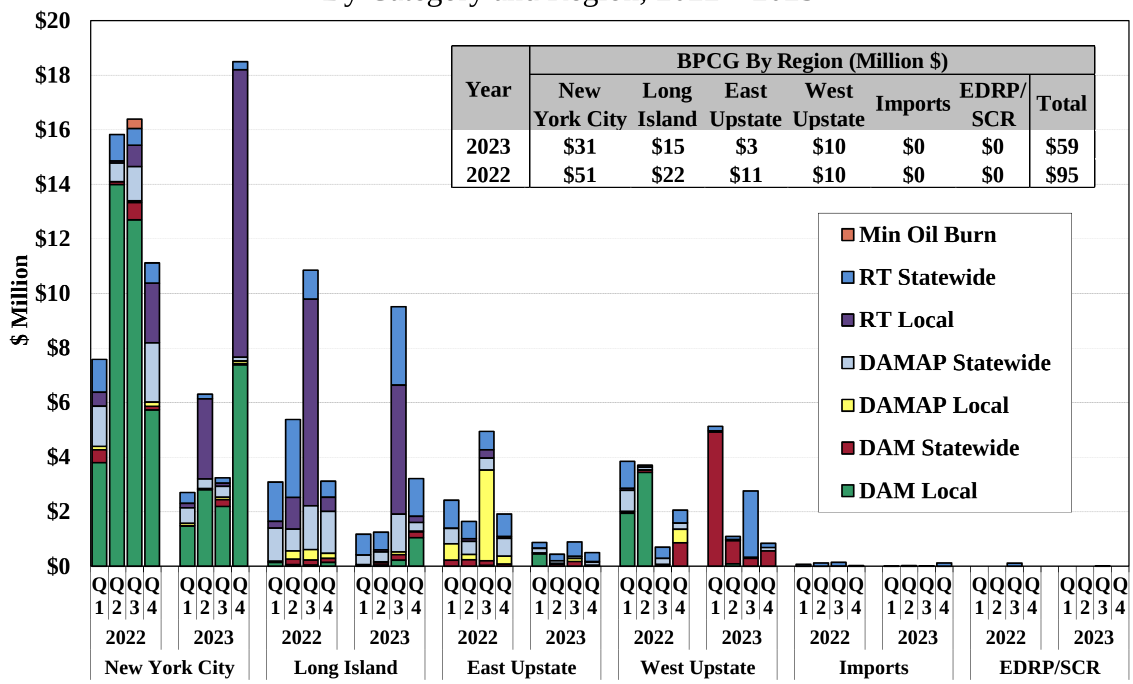
Thus, the NYISO holds substantial reserves on resources not scheduled (or compensated) in the day-ahead market. It would be beneficial to model this reliability need as a reserve requirement, and procure and price such reserves in the market by setting dynamic reserve requirements.[93] In some cases, reserve requirements could be satisfied by resources with longer lead times than the current 10 and 30-minute reserve providers. Hence, we recommended that NYISO evaluate the need for longer lead-time reserve products.[94] 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. The NYISO should consider these tradeoffs in its evaluation of dynamic reserves.

F. Guarantee Payment Uplift Charges

When suppliers scheduled by NYISO do not receive their as-offered costs from the sale of energy and ancillary services, they receive supplemental guarantee payments. NYISO recovers these payments through guarantee payment uplift charges. These uplift charges are difficult to hedge and do not provide transparent economic signals to market participants and potential 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 25 shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2022 and 2023 on a quarterly basis.[95]

Figure 25: Uplift Costs from Guarantee Payments in New York

By Category and Region, 2022 – 2023



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2023	$31	$15	$3	$10	$0	$0	$59
2022	$51	$22	$11	$10	$0	$0	$95

93 See Recommendation 2015-16.

94 See Recommendation 2021-1.

95 See Figure A-110 and Figure A-111 in the Appendix for a more detailed description of this analysis.

Guarantee payment uplift totaled $59 million in 2023, marking a 38 percent decrease from 2022. The reduction was driven primarily by lower natural gas prices, which decreased the commitment cost of gas-fired units. Moreover, decreased supplemental commitments in New York City and fewer OOM actions on Long Island were also important contributors.

In 2023, BPCG uplift in New York City fell 40 percent from 2022 because of lower natural gas prices, reduced NOx emission costs, and a decrease in supplemental commitments. 45 percent of this BPCG uplift was paid to generators that were committed for N-1-1-0 local requirements.

We have recommended the NYISO 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.[96] Roughly 40 percent of this BPCG uplift accrued on several days in June and October, which we attributed to supplemental commitments in real-time during local gas pipeline outages. BPCG for these commitments was increased because certain dual fuel steam turbines require natural gas to ramp up incremental output. This required the units to operate at a higher output level on oil for extended periods to provide local reserves. Since these reserve requirements are satisfied using OOM commitments and costs are recovered through guarantee payments, there are relatively weak market incentives to satisfy these requirements in a more cost-effective manner.

BPCG uplift on Long Island fell 32 percent in 2023. Approximately $5 million was paid in the category of real-time local BPCG uplift, with 73 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 the NYISO consider modeling local TVR requirements on Long Island in the day-ahead and real-time markets.[97] 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.[98]

Most of the $13 million in BPCG uplift payments paid in upstate regions in 2023 went to units that were either supplementally committed or dispatched out-of-merit to manage non-market-secured transmission constraints or local reserve needs. For example, more than $6 million was paid to units that were supplementally committed to manage local reserve needs in the North Country load pockets (143 days in 2023). It would be beneficial to incorporate more of these requirements into the day-ahead and real-time markets.

[96] See Recommendation 2017-1.

[97] See Recommendation 2021-3.

[98] See Section VII.B for this analysis.

VII. TRANSMISSION CONGESTION AND TCC CONTRACTS

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy 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 LBMPs reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

Congestion charges are applied to purchases and sales (including bilateral transactions) in the day-ahead and real-time markets based on the congestion components of day-ahead and real-time LBMPs.[99] 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 day-ahead congestion charges between two locations. However, no TCCs are sold for real-time congestion since most power is scheduled through the day-ahead market.

Transmission owners collect revenue from the sale of TCCs and from day-ahead congestion charges to recoup a portion of the embedded cost of building and maintaining the transmission network. To the extent transmission capability is sold in the TCC auctions, day-ahead congestion revenue is used to pay TCC holders, while any remaining portion is paid to transmission owners. Finally, any remaining embedded cost is recouped by Transmission Owners through a flat Transmission Service Charge (TSC) per MWh of real-time withdrawals.

This section discusses four aspects of congestion management in 2023:

- Day-ahead and real-time transmission congestion revenues (Subsection A),
- Transmission constraints managed using out-of-market actions rather than in the day-ahead and real-time markets (Subsection B),
- Transmission congestion contract 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 appendix evaluate elements of congestion management.[100]

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.

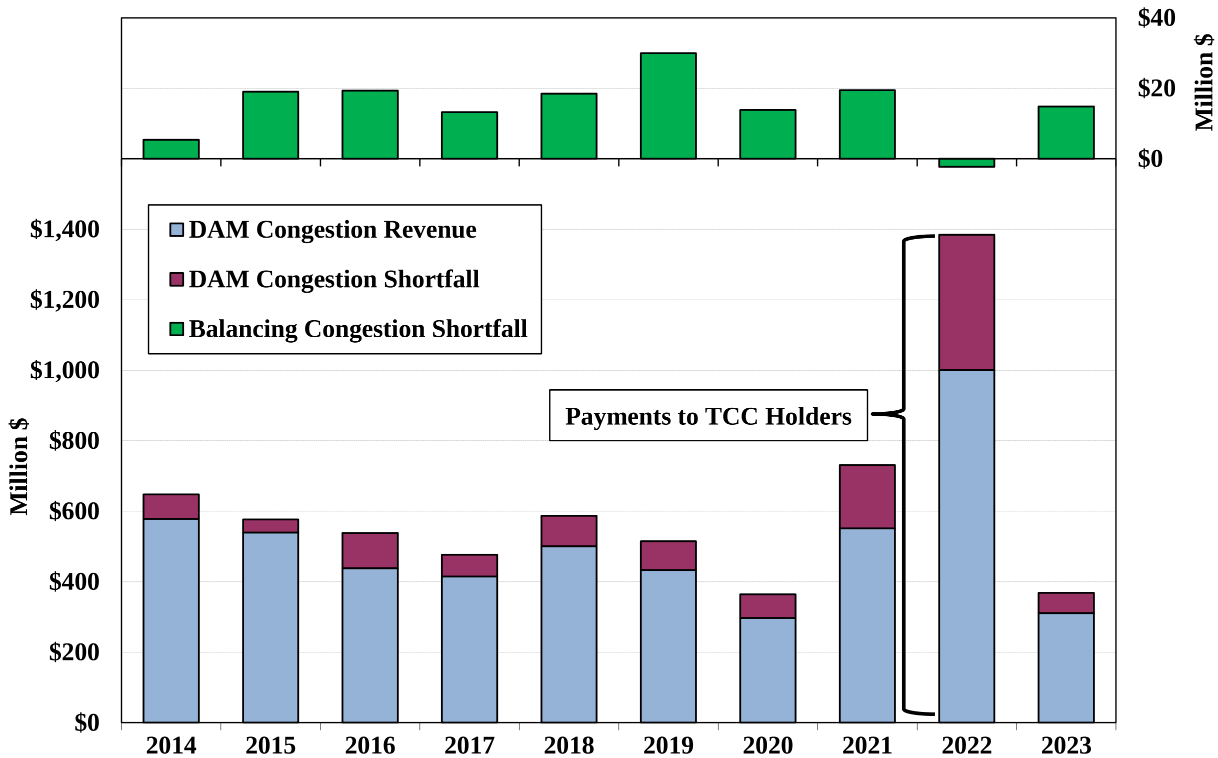
99 Congestion charges to bilateral transactions scheduled through the NYISO are based on the difference in congestion component of the LBMP between the two locations (i.e., the sink minus the source).

100 See evaluations of pricing during transmission shortages (VIVI.A), use of reserves to manage NYC congestion (Appendix VV.D), and coordinated congestion management with PJM (Appendix V.E).

Figure 26 evaluates overall congestion revenues and shortfalls in the past ten years, showing annual summaries of:

- *Day-ahead Congestion Revenues* – These are collected by the 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 results when the amount of TCCs sold by the NYISO exceeds the transmission capability of the power system as modeled in the day-ahead market. Shortfalls highlight outages and other factors that reduce transmission capability over constrained interfaces. Surpluses occur when day-ahead schedules utilize transmission capability not sold in the TCC auctions.
- *Balancing Congestion Shortfalls (and Surpluses)* – Shortfalls arise when day-ahead scheduled flows over a constraint exceed real time scheduled flows. Shortfalls highlight outages, loop flows, modeling inefficiencies, and other operational factors that reduce transmission capability from levels expected in the day-ahead market. Surpluses occur when real-time schedules utilize transmission capability not sold in the day-ahead market.

Figure 26: Congestion Revenues and Shortfalls
2014 – 2023



The figure shows a dramatic decrease in both day-ahead congestion revenues and day-ahead congestion shortfalls in 2023 from 2022, while balancing congestion shortfalls rose to levels typically seen in the past. We discuss these changes further in the subsections below.

1. Day-Ahead Congestion Revenues

Day-ahead congestion revenues fell to $311 million in 2023, marking a 69 percent decrease from 2022 and nearing the lowest level observed ($297 million) over the past decade. The sharp reduction in congestion was primarily attributable to lower natural gas prices and narrower gas price spreads between regions, which led to lower redispatch costs. Average gas prices fell by 60 to 70 percent across the state from 2022 to 2023. Forty-six percent of day-ahead congestion revenues were generated in the first quarter when gas prices spiked on cold days, leading to increased congestion from Central to East New York.[101]

Congestion was also reduced by less frequent planned transmission outages in 2023 than during the construction of major transmission projects over the past two years. As major transmission upgrades have been completed, congestion in the affected regions has been greatly reduced. The completion of the Smart Path project in June 2023 alleviated congestion from North to Central New York. The AC Transmission Segment A and Segment B projects completed at the end of 2023 significantly reduced congestion across the Central-East interface and from Capital to Hudson Valley. However, congestion across the Central-East interface still accounted for 53 percent of day-ahead congestion in 2023.

In contrast, Long Island congestion did not decrease in 2023 because of lengthy forced outages of lines into Long Island and sub load pockets. One of the two 345 kV lines from upstate to Long Island was out of service for nearly 200 days. Additionally, the Cross Sound Cable (which imports power from Connecticut) was out of service from early-August to early-December, leading to increased west-to-east flows and congestion on Long Island.

Unlike other regions, transmission paths from West to Central New York saw modestly increased congestion. This increase was primarily attributable to the new entry of wind resources in the Finger Lakes area. Most of this congestion accrued on bottlenecks limiting west-to-east flows along the Southern Tier of Central New York.

2. Day-Ahead Congestion Shortfalls

Day-ahead congestion shortfalls occur when day-ahead network capability is exceeded by the combination of TCCs issued, while day-ahead congestion surpluses (i.e., negative shortfalls) occur when day-ahead schedules across constrained interfaces exceeds the amount of TCCs sold. Table 4 shows total day-ahead congestion shortfalls for selected transmission facility groups.[102]

Day-ahead congestion shortfalls fell from $384 million in 2022 to $59 million in 2023 primarily because of fewer planned transmission outages (that are not accounted for in the TCC market).

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[101] See Appendix Section III.B for congestion revenues by transmission facility group.

[102] Appendix Section III.F provides descriptions and detailed results for each transmission facility group.

Table 4: Day-Ahead Congestion Shortfalls in 2023

Facility Group	Annual Shortfalls ($ Million)
Central to East	$59
North to Central	$6
Long Island Lines	$2
All Other Facilities	-$8

Day-ahead congestion shortfalls were elevated in 2021 ($180 million) and 2022 ($384 million) because of transmission outages needed to facilitate Public Policy Transmission projects. Notably, day-ahead congestion shortfalls in 2023 were below the ten-year average from 2011 to 2020, which was $70 million. We discuss shortfalls by transmission path below.

Central to East – Shortfalls on this path fell from $335 million in 2022 to $59 million in 2023, accounting for nearly all shortfalls in both years. Shortfalls in 2022 were driven by outages to support construction work for the Central East Energy Connect project. Nonetheless, some notable transmission outages in 2023 that incurred substantial costs include:

- The Edic-Fraser 345 kV circuit (“EF24-40 line”) was out of service from February 13 to 18, and from March 1 to April 11, resulting in a reduction of the interface transfer limit by approximately 310 MW.
- The Gordon Road-Prince Town 345 kV circuit (“371 line”) and the Princetown-New Scotland 345 kV circuit (“55 line”) were out of service from March 20 to April 19, leading to a decrease in the interface limit by approximately 540 MW.
- The Frasannx-Coopers 345 kV circuit (“UCC2-41 line”) was out of service from October 16 to 27, which reduced the interface limit by approximately 445 MW.
- The Massena-Marcy 765 kV circuit (“MSU1 line”) was out of service from November 15 to 27, causing a reduction in the interface limit by approximately 1000 MW.

North to Central New York lines – This path also experienced significant shortfalls, accounting for $6 million in 2023. The primary driver was transmission outages taken throughout the year for the Smart Path Connect Project in the North and Mohawk Valley load zones.

Long Island – Long Island lines accounted for a net of $2 million of shortfalls in 2023, but this arose from a combination of large shortfalls and surpluses. The shortfalls were driven by the following outages of tie lines between upstate and Long Island:

- The Sprainbrook-East Garden City 345 kV circuit (“Y49 line”) was out of service for a total of 158 days in the first half of 2023.
- The Dunwoodie-Shore Road 345 kV circuit (“Y50 line”) was out of service for a combined 40 days in the last three months of 2023.

The resulting shortfalls were largely offset by two categories of congestion surpluses. First, the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) contributed $4 million of congestion surpluses. These lines consistently caused congestion surpluses because the assumed flows from Long Island to New York City across the two lines was typically 300 MW in the TCC auctions and just 206 MW in the day-ahead market in 2023. Since these flows are generally 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 underscores that scheduling the 901 and 903 lines in an efficient manner would substantially reduce production costs.[103] Second, another $4 million of surpluses accrued in July when TCCs into Long Island were not fully sold following the expiration of two long-term TCC contracts. The full amount of TCCs resumed in the August auction.

The NYISO allocates most of the day-ahead congestion shortfalls that result from transmission outages to the specific responsible transmission owners.[104] Allocating congestion shortfalls to the responsible transmission owners provides incentives to minimize the overall costs of transmission outages. The allocation of day-ahead shortfalls and surpluses is discussed further in Subsection D.

3. Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in transmission capability from the day-ahead market to the real-time market, while surpluses (i.e., negative shortfalls) occur when real-time flows on a binding constraint are higher than those in the day-ahead market. Unlike day-ahead shortfalls, balancing congestion shortfalls are generally socialized to all NYCA load through Rate Schedule 1 charges.[105] Table 5 shows balancing congestion shortfalls by transmission facility group.[106] [107]

Table 5: Balancing Congestion Shortfalls in 2023

Facility Group	Annual Shortfalls ($ Million)
Central to East	
Ramapo, A & JK PARs	**-$8.2**
Other Factors	**$7.1**
Long Island Lines	**$5.1**
New York City Lines	**$4.5**
North to Central	**$4.0**
All Other Facilities	**$0.5**

103 See Recommendation 2012-8.

104 The allocation method is described in NYISO Open Access Transmission Tariff, Section 20.

105 The only exception is that some balancing congestion shortfalls from TSA events are allocated to ConEd.

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

107 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.

Congestion shortfalls are modest on most days but can escalate significantly on a limited number of days due to unexpected events. For example:

- The Massena-Marcy 765kV circuit ("MSU1 line") experienced a forced outage from August 17 to 19, resulting over $6 million in congestion shortfalls on transmission paths from North to Central and across the Central-East interface.
- Operational issues with the A PAR towards the end of the year led to nearly $4 million in shortfalls accumulated on nearby facilities in New York City.
- The Y49 and Y50 lines into Long Island experienced multiple trips throughout the year, contributing to a significant portion of the $5 million shortfalls accrued on Long Island.

However, these shortfalls were offset by surpluses generated by the NJ-NY PARs (Ramapo, A, & JK PARs) during their real-time operations under the PJM-NY M2M process. In 2023, these PARs contributed more than $8 million in surpluses on transmission paths across the Central-East interface. This has provided significant benefits to customers in New York.

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

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

- More efficient scheduling of resources that optimally balance the costs of satisfying demand, ancillary services, and transmission security requirements; and
- More efficient price 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, some transmission constraints, particularly 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 an internal interface/constraint transfer limit that functions as a proxy for the limiting transmission facility; and
- Adjusting PAR-controlled line flows on the higher voltage network.

The NYISO started to incorporate most 115 kV constraints in the day-ahead and real-time markets in December 2018.[108] Furthermore, the NYISO has incorporated five 69 kV constraints

108 In addition, the NYISO improved modeling of the Niagara plant to better recognize the different congestion impact from its 115 kV and 230 kV units in December 2018. The plant consists of seven generating units on the 115 kV network and 18 generating units on the 230 kV network, and output can be shifted among these generators to manage congestion on both networks and make more of the plant's output deliverable.

on Long Island in the day-ahead and real-time markets since mid-April 2021.[109] These developments have allowed resources that were 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 in Upstate New York and Long Island.

Notwithstanding these improvements, out-of-market actions to manage constraints are still frequent in some areas. Table 6 shows the frequency of such actions in several areas. The table shows the number of days from 2022 to 2023 when OOM actions were used in each area.[110]

Table 6: Constraints on the Low Voltage Network in New York

Summary of OOM Days for Managing Constraints, 2022-2023

Area	# of Days with OOM Actions	
	2022	2023
North Zone	73	188
New York City	320	265
Long Island	135	172
All Other Regions	154	68

New York City experienced the most frequent OOM actions of any region in the past two years. Most of these actions were commitments to satisfy N-1-1 requirements in New York City load pockets. OOM commitments fell in 2023 primarily because of the elimination of NOx system-averaging requirements after the retirement of gas turbines at the Astoria and Gowanus facilities.

In the North Zone, OOM actions rose from 2022 to 2023, primarily to commit generation to satisfy N-1-1 requirements in the North Country load pocket, which are not currently modeled in the day-ahead and real-time markets. Such OOM commitments occurred on 143 days in 2023, compared to 67 days in 2022. Large OOM commitments occurred on many days when reserve needs were small (< 10 MW), leading to sizable uplift given the reliability benefits. In addition, wind curtailments occurred on 86 of the 143 days partly because of increased production from the OOM committed units. Although the North Zone usually exports power, when the NYISO determines whether to commit generation out-of-market to satisfy local N-1-1 requirements, wind generators are heavily discounted relative to their day-ahead schedules. Hence, reliability commitments increase supply in the area, leading to increased wind curtailment.

In Long Island, supplemental commitments were made for reserve needs typically under tight system conditions driven by severe weather, constrained gas supplies, emergency outages of

109 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.

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

inter-ties, or generator tripping. Long Island had such OOM commitments on 27 days in 2022 and 2 days in 2023 because of milder system conditions. We have recommended the NYISO model the full reserve requirements for Long Island in the day-ahead and real-time markets.[111] It would be beneficial to model full reserve requirements in other applicable local areas such as the North Country load pocket. Modeling these local N-1-1 requirements in the market software would improve scheduling efficiency, send efficient investment signals, and help integrate renewable and storage resources.

OOM actions to manage low-voltage network constraints are still most frequent on Long Island. Table 7 evaluates the frequency of OOM actions (including the total number of hours and days) to manage 69 kV constraints and Transient Voltage Recovery (TVR) constraints in four areas of Long Island in 2022 and 2023. The table also shows the average estimated LBMP in each pocket based on the marginal costs of resources used to manage the constraint(s).

Table 7: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2022-2023

Year	Long Island Load Pockets	69kV OOM		TVR OOM		Avg. LBMP	Est. LBMP w/ Modeling Local Constraints
		#Hours	#Days	#Hours	#Days		
2022	Valley Stream	604	65			$98.08	$99.50
	Brentwood	38	8			$98.31	$98.34
	East of Northport	148	25			$97.30	$98.37
	East End	84	7	814	68	$99.40	$127.95
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

OOM actions to secure 69 kV facilities on Long Island have become less frequent since April 2021, when NYISO began to incorporate 69 kV constraints in the market software. This has allowed resources that were frequently dispatched OOM to manage these constraints to be scheduled economically on 133 days in 2022 and 112 days in 2023. OOM actions to manage 69 kV constraints have declined more than 50 percent from the levels typically seen prior to 2021.

The NYISO has a process to periodically evaluate and incorporate additional 69 kV constraints into the market models as needed, which should help further reduce such OOM needs on Long Island and improve scheduling and pricing efficiency. Continuing to set LBMPs on Long Island more efficiently to recognize the marginal cost of satisfying local transmission constraints will provide better signals for future investment. However, this process does not address the TVR

111 See Recommendation 2021-2.

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.[112] 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 2022/23 and Summer 2023 Capability Periods (i.e., November 2022 to October 2023). Table 8 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[113]

- 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 8: TCC Cost and Profit

Winter 2022/23 and Summer 2023 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
Central Zone	$39	-$8	-20%
Mohawk VL	-$76	$44	-59%
Capital Zone	$76	-$18	-24%
Long Island	$15	-$1	-7%
New York City	$15	-$7	-44%
All Other	$1	$4	498%
Total	**$70**	**$14**	**20%**
Inter-Zonal TCC			
Other to Central New York	$74	-$36	-49%
Other to Southeast New York	$433	-$345	-80%
New York to New England	$178	-$132	-74%
All Other	$21	-$10	-50%
Total	**$706**	**-$523**	**-74%**

112 See Recommendation 2021-3.

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

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2022 to October 2023 netted a total *loss* of $508 million. Overall, the net profitability for TCC holders in this period was *negative* 66 percent (as a weighted percentage of the original TCC prices), compared to *positive* 28 percent in the previous 12-month period. TCC holders experienced average *losses* of 74 percent on inter-zonal transmission paths, while realizing an average *gain* of 20 percent on intra-zonal paths. The significant reduction in natural gas prices coupled with fewer costly transmission outages were the main factors contributing to the lower-than-anticipated congestion across the state. This resulted in participants incurring net losses on the majority of intra-zonal and inter-zonal transmission paths within these regions.

The most substantial losses, totaling $345 million, occurred across the Central-East interface and the paths into Southeast New York. This coincided with a 73 percent reduction in day-ahead congestion along these transmission paths from 2022 to 2023. Decreased natural gas spreads between regions, lower net imports from Ontario and Quebec, and fewer transmission outages reduced the west-to-east transmission bottlenecks from levels experienced in 2022. Conversely, participants realized a profit of $44 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.

The 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.

Given that 100 percent of the transmission system's capability is available for sale in the form of TCCs of six-months or longer, very little revenue is collected from the monthly Balance-of-Period Auctions. Hence, selling more of the capability of the transmission system in the monthly Auctions (by holding back a portion of the capability from the six-month auctions) would likely raise the overall amount of revenue collected from the sale of TCCs.

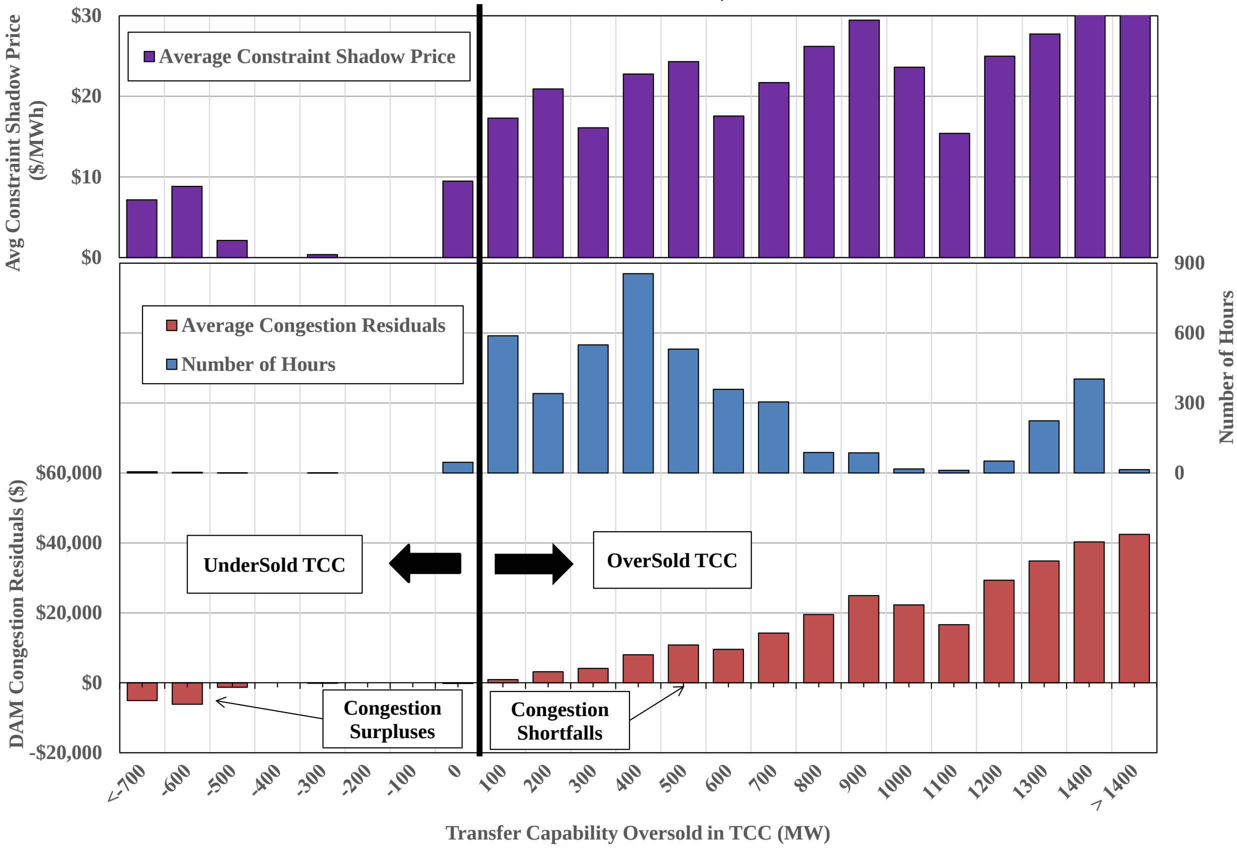
D. Allocation of Day-Ahead Congestion Shortfalls and Surpluses

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 section evaluates various categories of residuals and the extent to which they are allocated efficiently.

Figure 27 shows the amount of oversold or undersold TCCs relative to day-ahead scheduled flows in hours when the Central-East interface was binding in 2023. Hours are grouped on the horizontal axis based on the net quantity oversold (i.e., the amount of transfer capability used by TCCs minus the available transfer capability in the day-ahead market). For each group of hours, the figure shows the number of hours, the average constraint shadow price, and the average congestion shortfall or surplus.[114]

Figure 27: Oversold TCC vs. DAM Congestion

Central-East Interface, 2023



This figure illustrates how day-ahead congestion shortfalls and surpluses fluctuate based on outages modeled in the day-ahead market and the TCC sold in forward auctions. The transfer capability over the Central-East interface fluctuated significantly throughout the year because of construction work on the Segment A and Segment B Public Policy transmission projects. Large deratings (relative to modeled capability in the TCC auctions) occurred in the first half of the year when prolonged transmission outages were frequently taken to facilitate construction work.

114 See Figure A-57 in the Appendix for more detailed chart description.

As transmission upgrades were gradually completed and put into service leading into the summer months, deratings became smaller. By the end of 2023, transfer capability modeled in the day-ahead market usually exceeded obligations to TCC holders. Hence, TCCs were oversold for most of the year and undersold TCCs towards the end of year.

The figure illustrates how overselling TCCs leads to congestion shortfalls and underselling results in surpluses. The Central-East interface was binding in the day-ahead market in more than 50 percent of hours. TCCs were oversold in the vast majority of these hours, while TCCs were undersold in fewer than 60 hours. As a result, the majority of associated congestion residuals were shortfalls, amounting to a net of $59 million in 2023.

The figure shows a positive correlation between average constraint shadow prices and the amount of oversold TCCs. Modeled transfer capability in the TCC auctions is generally fixed for six months at a time, so we can infer that shadow prices rise when transfer capability over the constraint is lower in the day-ahead market. Although constraint shadow prices are affected by other factors such as gas prices, generation availability, and load patterns, the amount of modeled transfer capability in the day-ahead market is a key driver of shadow prices. This reflects that when day-ahead transfer capability increases, allowing more supply in low-cost areas to be delivered to high-cost areas, the difference in marginal cost of supply between upstream and downstream areas tends to shrink.

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.[115] 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.[116]

The following example illustrates how the allocation of surpluses is not consistent with cost causation in some cases. Suppose a constraint binds in the day-ahead market with a scheduled flow of 300 MW while TCCs have been sold that utilize 260 MW of transfer capability (i.e., the constraint is undersold by 40 MW). If the additional 40 MW was made available by an uprate of the facility after the TCC auction, the TO receives 40 MW worth of congestion surpluses from the day-ahead market. However, if the additional 40 MW arises because the TCC auctions sold less than the full transfer capability of the line, then the responsible TO receives only a small

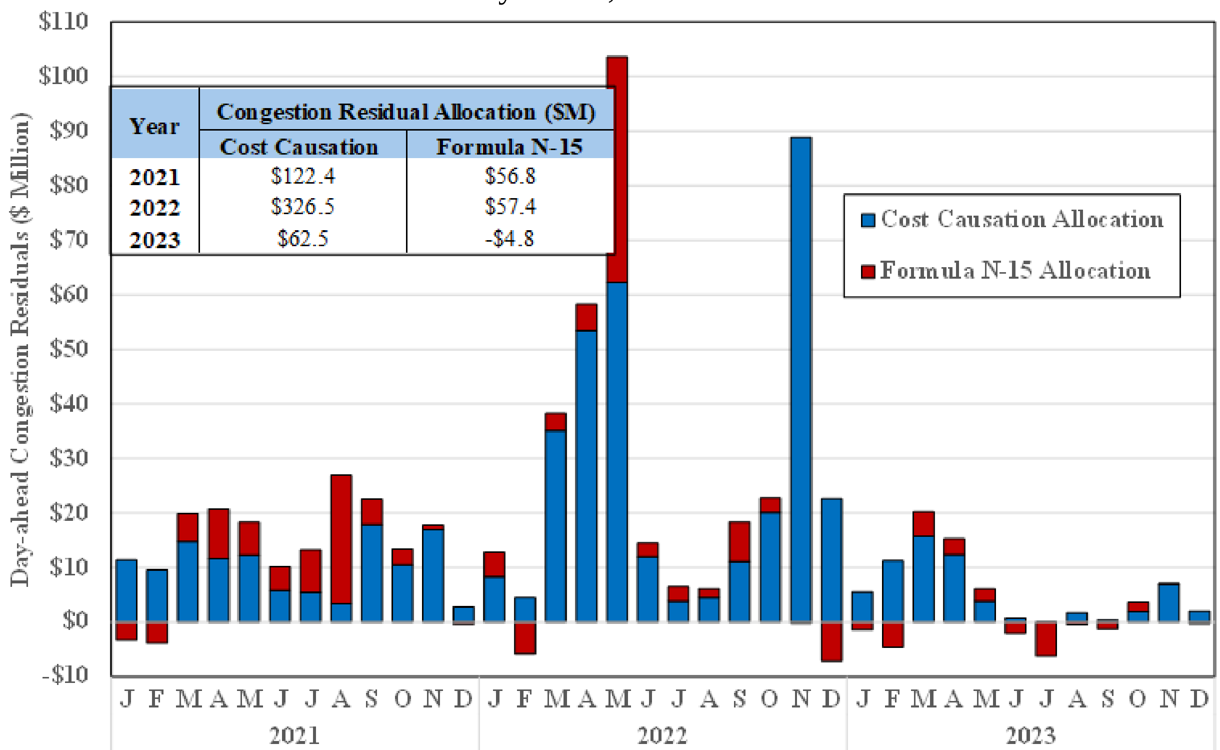
115 See OATT, Attachment N, Formula N-6 through N-14 for the calculation of these allocations.

116 See OATT, Attachment N, Formula N-15 for the calculation of this allocation.

portion of the resulting congestion surpluses. This allocation is inefficient and penalizes TOs that own equipment on interfaces that bind under multiple transmission flow patterns.[117]

Figure 28 shows actual allocations of day-ahead congestion residuals for each month over the past three years. The blue bars represent the portion allocated based on a cost causation principle (which include Formulas N-6 through N-14), while the red bars represent the portion allocated based on TCC revenues using Formula N-15 in the OATT Attachment N.

Figure 28: Allocation of DAM Congestion Residuals
By Month, 2021-2023



The vast majority of N-15 shortfalls resulted from reductions in the Central-East interface limit due to changes in the operation of 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

117 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.

of TOs. This allocation does not provide incentives to operate this transmission equipment efficiently.

Most of the N-15 surpluses arose when interfaces were binding in the day-ahead market that had been undersold in the TCC auction. Such congestion tends to result from changes in the pattern of generation and load, shifting the pattern of congestion across the transmission network. This type of congestion 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 value of their transmission assets when they are undersold in the TCC auctions. This creates incentives to oversell the capability of the transmission system in the TCC auction.[118]

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.[119]

118 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.

119 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 for transmission investments (Subsection F), and
  - Reflecting seasonal capacity value in Subsection G.

A. Capacity Market Results in 2023

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices. Table 9 shows average spot auction prices for each locality for the 2023/24 Capability Year and year-over-year changes in key factors from the prior Capability Year. Table 9 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 as a result of the NYDEC Peaker Rule regulations. Additionally, a higher load forecast and LCR contributed to higher New York City prices, which increased by an average of $13 per kW-month from the previous year. Notably, summer prices in New York City exceeded the Net Cost of New Entry in the 2023/24 Capability Year.

Table 9: Capacity Spot Prices and Key Drivers by Capacity Zone[120]
2023/24 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2023 Margin (% of Requirement)	4.3%	8.5%	2.6%	13.1%
Net Change from Previous Yr	-4.0%	-3.4%	-12.8%	1.3%
Average Spot Price (Full Year)				
2023/24 Price ($/kW-month)	$4.11	$4.17	$15.97	$4.11
Percent Change Yr-Yr	51%	46%	437%	-7%
Change in Demand				
Load Forecast (MW)	282	268	333	-56
IRM/LCR	0.4%	-3.8%	0.5%	5.7%
ICAP Requirement (MW)	338	-346	327	234
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-521	-796	-629	245
SCR (MW)	104	12	8	4
Import Capacity (MW)	-666			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	-5%	-16%	-2%	-12%
Net Change in Derating Factor Yr-Yr	0.4%	-0.1%	-1.6%	1.0%

Supply margins in the NYCA and G-J Locality regions also tightened due to the peaker retirements in New York City. These regions also had higher load forecasts than in the previous year, while imports from external areas to NYCA fell significantly. As a result, the annual average NYCA price increased by $1.39 per kW-year to $4.11. Prices in the G-J Locality were set at the NYCA price in most months of 2023/24 because of decline in the G-J Locality LCR. In Long Island, a higher LCR was offset by increased UDR supply and a slightly lower load forecast. As a result, the Long Island price was set by the NYCA price in all months of 2023/24.

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.

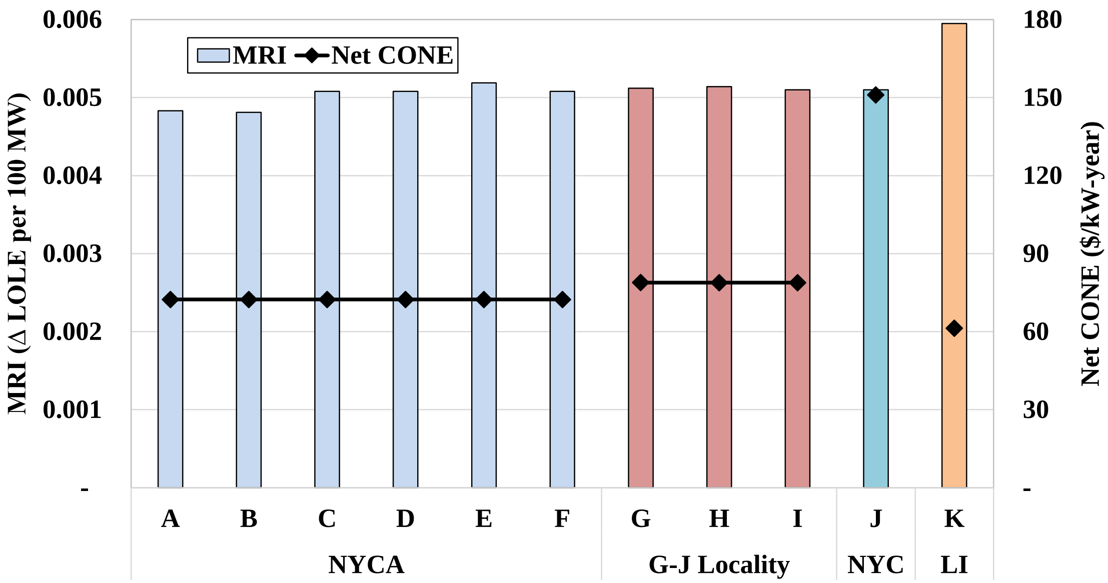
120 See Section VI.D in the Appendix for more details.

In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the upcoming 2024/25 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 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.[121]
- 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 29 and Figure 30 show the estimated MRI, Net CONE, and CRI for each locality and zone based on the 2024/25 Final LCR Case.[122]

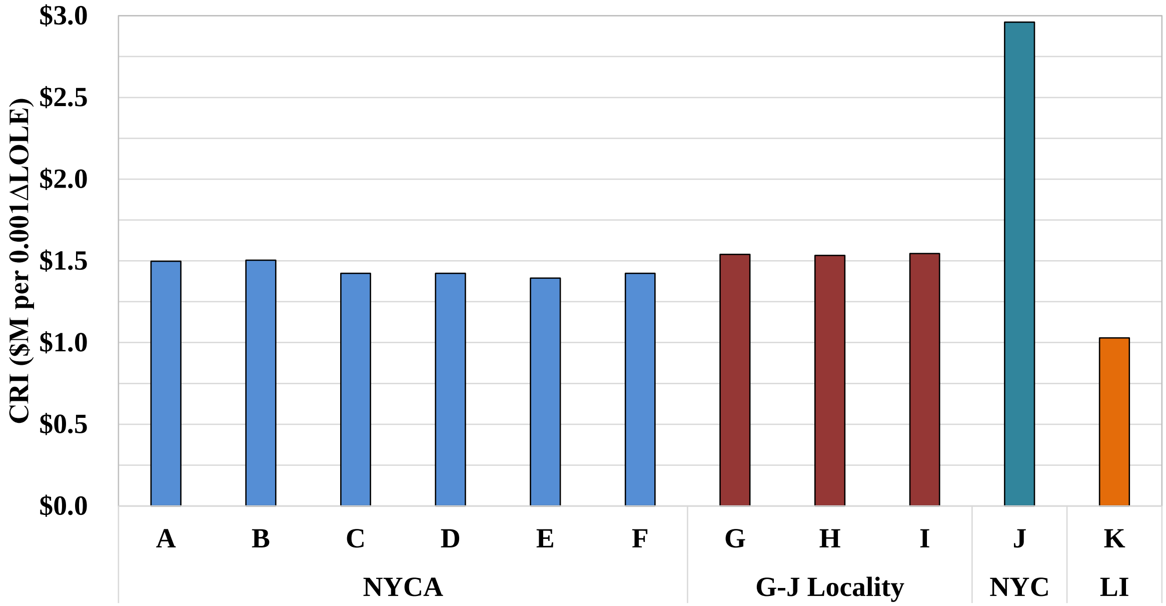
Figure 29: Marginal Reliability Impact (MRI) and Net CONE by Locality and Zone
2024/2025 Capability Year at Level-of-Excess Conditions



121 The MRI is similar to marginal Electric Load Carrying Capability ("ELCC"). These two approaches are compared in Appendix Section VI.I

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

Figure 30: Cost of Reliability Improvement (CRI) by Locality
2024/2025 Capability Year at Level-of-Excess Conditions



It is apparent from Figure 30 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 $1.0 million per 0.001 events) and the maximum CRI location of Zone J (at $3.0 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 2024/25 Capability Year (105.3 percent) is below the efficient level. The TSL-based floor does not prevent the Optimizer from selecting a higher LCR value for a locality.

Issues with LCR Optimizer: The LCR Optimizer uses an 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.[123] In 2023, the NYISO proposed changes in the objective function to minimize investment costs, planned to be deployed in the 2025/26 capability year.[124] We support the NYISO's proposal, which is needed to produce efficient LCRs using the Optimizer. It will also be needed to implement more granular capacity zones as discussed in this section.

The LCR Optimizer may also fail to set efficient LCRs due to misalignment with the IRM process. The LCR values are strongly affected by the IRM, which acts as a constraint in the

123 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.

124 See NYISO presentation to December 13, 2023 Business Issues Committee, available here.

LCR Optimizer that limits the range of possible LCR outcomes. However, the IRM itself embeds estimated LCRs determined using a different method from the Optimizer.[125] As a result, changes to the IRM can cause volatility in the LCRs.

Impact of Transmission Security Limits: The LCRs for the NYC, Long Island, and 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. The impacts of the TSLs is discussed further in Subsection E.

Overly Broad Pricing Zones: Figure 30 shows that the CRI values for zones A and B are higher than for other zones in the Rest of State region. In recent LCR studies we have also frequently seen a lower MRI and higher CRI in Zone G compared to zones H and I, driven by bottlenecks on the UPNY/CONED interface, as well as a lower MRI for resources in Staten Island compared to the rest of New York City. Subsection C discusses improving locational capacity prices by defining more granular capacity zones to account for intrazonal transmission bottlenecks.

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 regions roughly capture the locations of historical transmission bottlenecks that limit capacity deliverability during summer peak periods.[126] 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

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125 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.

126 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.

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.
- *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 a large portion of proposed new resources 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.

Overview of Proposal

We recommend that NYISO establish a dynamic process to update capacity zones used to set prices (Recommendation 2022-4).[127] 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.[128] Its primary effect would be to: (1) discount capacity payments to export-

127 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).

128 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

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.[129] In reality, there are also internal bottlenecks within the load zones that limit deliverability of capacity. For example, recent deliverability studies indicate that binding export constraints exist in Staten Island, eastern and central Long Island, northern New York (including northern parts of Zone E), and part of Queens. 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

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 XII 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.

129 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.

outcomes of MARS will differ from a deterministic power flow assessment.[130] 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.

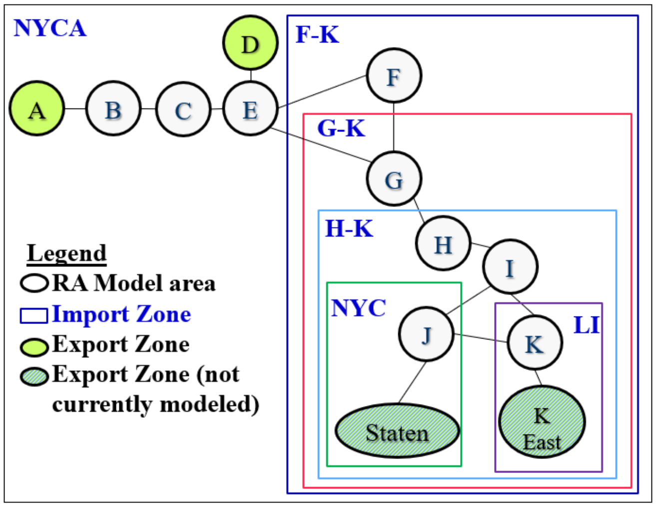
2. Designate capacity zones as import or export-constrained based on configuration of binding constraints in the resource adequacy model

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 31 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 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 31: Illustration of Import and Export Zones After LI PPTN Projects In Service



[130] 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.

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 the 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.[131] 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.[132] 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.[133] The requirements of export zones would be included in the requirements of the parent import zone.

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

131 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.

132 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.

133 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.

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 32: Export Zone Demand Curve

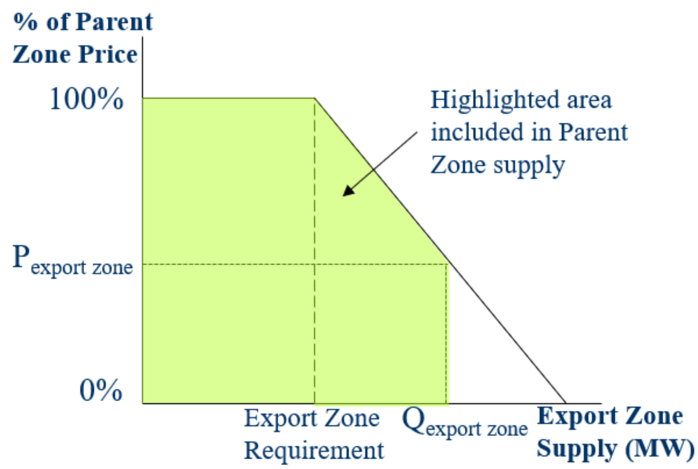


Figure 32 illustrates this concept. When capacity in the export zone is less than or equal to the export zone requirement, payments are equal to the parent zone price because all of the export zone's capacity is deliverable. Surplus beyond the export zone's requirement causes the price paid to fall as 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.[134]

[134] 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.

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 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 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.[135]

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 modeling the following types of resources:

- *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 amounts of stored fuel inventory. Winter fuel limitations of gas-only and dual fuel resources have not been modeled in MARS. NYISO has proposed improvements to the modeling and accreditation of these resources that would become effective in May 2025. However, major improvements are still needed to account for oil inventory limitations, which we discuss in Subsection G.
- *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 plans to consider this issue in 2026.[136]

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135 See https://www.nyiso.com/accreditation for capacity accreditation factors for the 2024/25 capability year.

136 See *NYISO Resource Adequacy Model Strategic Plan (2024-2028)*, presented by NYISO to NYSRC Executive Committee on September 8, 2023, available here, at slide 13.

- *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.[137] 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.[138]

  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.[139]
- *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 that NYISO consider improvements to more accurately evaluate marginal reliability contributions for: (a) gas-only generators with limited/no backup fuel, (b) inventory-limited resources, (c) energy 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 similar to the 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 currently over-estimates 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.[140] Operators may not commit this capacity in practice because of concerns that the emergency capacity

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

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

[139] See *NYISO Resource Adequacy Model Strategic Plan (2024-2028)*, presented by NYISO to NYSRC Executive Committee on September 8, 2023, available here, at slide 5.

[140] See NYISO Emergency Operations Manual.

cannot operate in a reliable manner, thereby increasing the risk of outage to the normal range of the generator's capacity.[141]

- *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.
- *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.
- *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 the NYISO without accounting for the full contractual obligations to their host steam demand.

NYISO has begun to address the issues with cogeneration capacity through improved DMNC test and approval procedures. In addition, NYISO plans to file soon to address some issues outlined above starting in May 2025.[142] 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.[143]

NYISO proposes to eliminate the Capacity Limited Resource (CLR) designation and requiring such units to offer the ICAP equivalent of the UCAP sold at the normal upper operating limit (UOL_N), which should reduce the sale of emergency capacity.[144] We will evaluate the effects of

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141 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.

142 See Management Committee presentation from March 27, 2024.

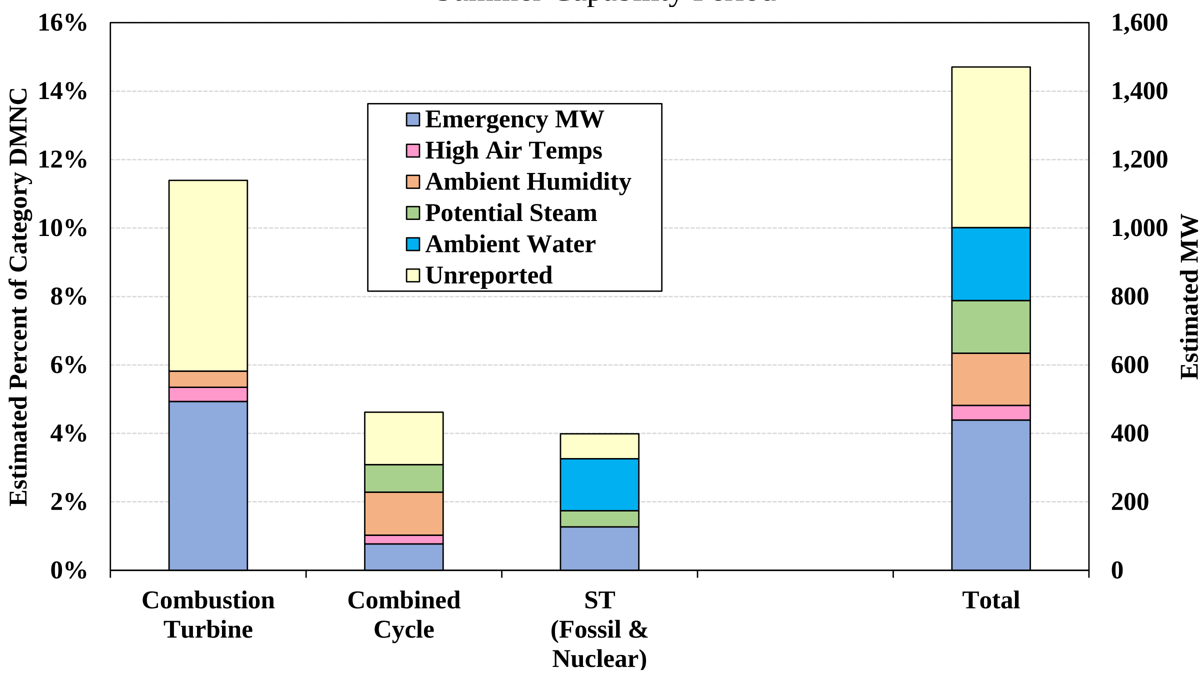
143 The NYISO's proposal for addressing water temperature dependent resources simply requires these generators to test in July or August between the hours of 10 AM and 10 PM. However, these timing restrictions do not address: (i) tidal effects, or (ii) the effect of multiple units at a station operating 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.

144 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.

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.[145]

Figure 33 shows the estimated ICAP that was functionally unavailable to the market during peak conditions last summer on fossil-fuel and nuclear units by category.[146] Approximately 1,470 MW of ICAP was functionally unavailable on the hottest days (including 440 MW that was "unreported" but which is likely to be from ambient humidity and water temperature effects).

Figure 33: Functionally Unavailable Capacity from Fossil and Nuclear Generators
Summer Capability Period



While the NYISO's filed changes will address much of this capacity, we recommend (see 2021-4) the following additional changes to DMNC testing and ICAP qualification processes:

- 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.

145 See Appendix Section VI.C.

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

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.[147] 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 the NYISO's planning studies, some resource types are assumed to contribute less towards transmission security requirements than resource adequacy requirements.[148] 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.
- 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.[149]

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.[150] 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.

147 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.

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

149 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.

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

Figure 34 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 2024/25 capability years, along with estimated TSL-floors for the 2025/26 and 2026/27 capability years. 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.[151] 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.[152] We also show the projected 2025/26 LCR if set by the LCR Optimizer based on a study by NYISO in 2022 that assumed a lower TSL-floor that was not binding.[153]

Figure 34: Historical and Projected New York City LCRs and TSLs

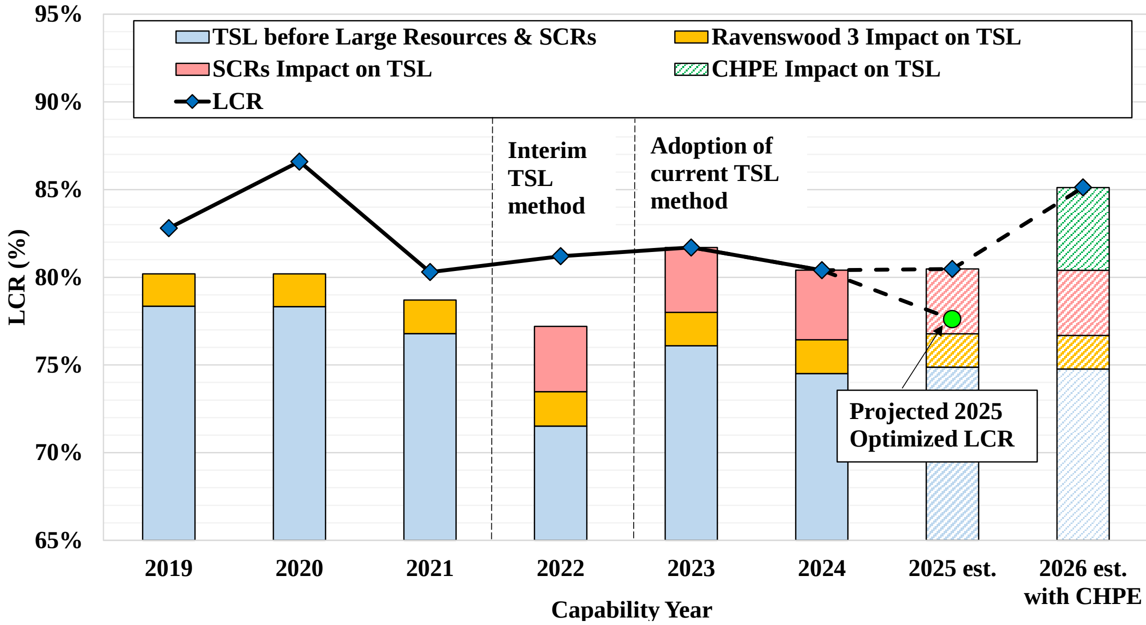


Figure 34 illustrates that the TSL-floor is increasingly likely to determine the New York City LCR. After adoption of the current methodology in 2022, the NYC LCR was set at its TSL-floor for 2023/24 and 2024/25 capability years. Our projected 2025/26 TSL-floor of 81.8 percent significantly exceeds NYISO's Optimizer-based projected LCR of 77.6 percent. After the CHPE line enters service, our projected 2026/27 TSL-floor further increases to 86.4 percent. TSL-floors lead to higher costs by requiring a larger amount of capacity to be held in higher-priced zones.

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151 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.

152 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.

153 See March 25, 2022 NYISO presentation to ICAPWG "AC Transmission and Peaker Retirements in IRM Study", available here. This study was not primarily intended to examine the impacts of TSLs and used a constant 77.2 percent TSL-floor in New York City, based on the 2022/23 TSL. The projected future LCRs from this study were based on information available at the time and are certain to change.

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 could be overcompensated by up to $47 million.[154]

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.[155]
- 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

154 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 442 MW summer and 243 MW winter SCR ICAP times the final four hour ELR CAF of 68.8 percent for the 2024/25 capability year and 215 MW of capacity from Ravenswood 3 that causes an increase in the TSL-floor.

155 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). NYISO has recently proposed improvements to SCR modeling and CAFs as part of the Modeling Improvements for Capacity Accreditation project (see here).

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.[156]

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.[157] Hence, the probability of load shedding due to insufficient capacity in a locality is vanishingly low when the locality satisfies transmission security requirements that significantly exceed resource adequacy-based requirements. For example, Figure 29 in Subsection B shows that the 2024/25 LCR case, which set all LCRs at TSL-floors, additional capacity in New York City provides no more reliability than capacity upstate at the tariff-prescribed level of excess.

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

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156 For more detail, see our comments on the 2023 Comprehensive Reliability Plan (CRP), available here.

157 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 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.

values defined by NYSRC, NPCC, or NERC reliability criteria.[158] 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 35 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 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 35: Expected Load Shed at Transmission Security Requirement

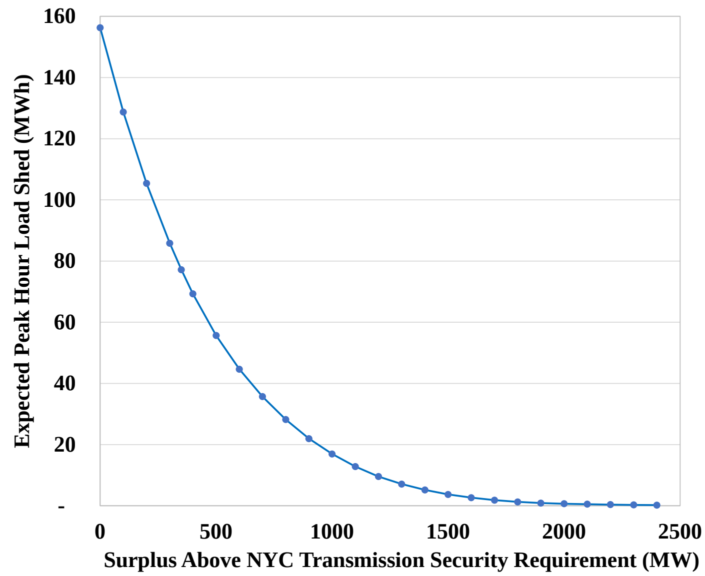


Figure 36 illustrates how the incremental value of surplus capacity for transmission security can be operationalized as a demand curve. It includes the following elements:

- The ‘Status Quo Demand Curve’ is the current sloped demand curve based on an ICAP requirement equal to the 2023-24 TSL-based requirement for New York City. It is designed to provide compensation equal to the demand curve unit’s Net CONE at the tariff-prescribed level of excess (LOE) and has a zero-crossing point at 118 percent of the TSL-based requirement.
- The ‘RA Demand Curve’ is the sloped demand curve that would prevail if the LCR was set by the LCR Optimizer instead of the TSL-floor. We assume an Optimizer-based LCR of 80.0 percent for this example, but the actual value of the 2023/24 LCR but for the TSL-floor is unknown.
- The ‘TS Demand Curve’ is set to provide revenues equal to Net CONE at the TSL-based requirement plus the LOE. It has a sloped shape based on the amount of incremental EUE at each level of surplus in Figure 35 relative to the EUE at the LOE.
- The ‘Effective Demand Curve’ is the price paid to New York City resources. It is the maximum of the RA Demand Curve or TS Demand Curve price at each surplus level. At larger surplus levels, the price is set by the nested NYCA (or G-J Locality) price.

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

Figure 36: Illustration of Transmission Security Demand Curve Concept

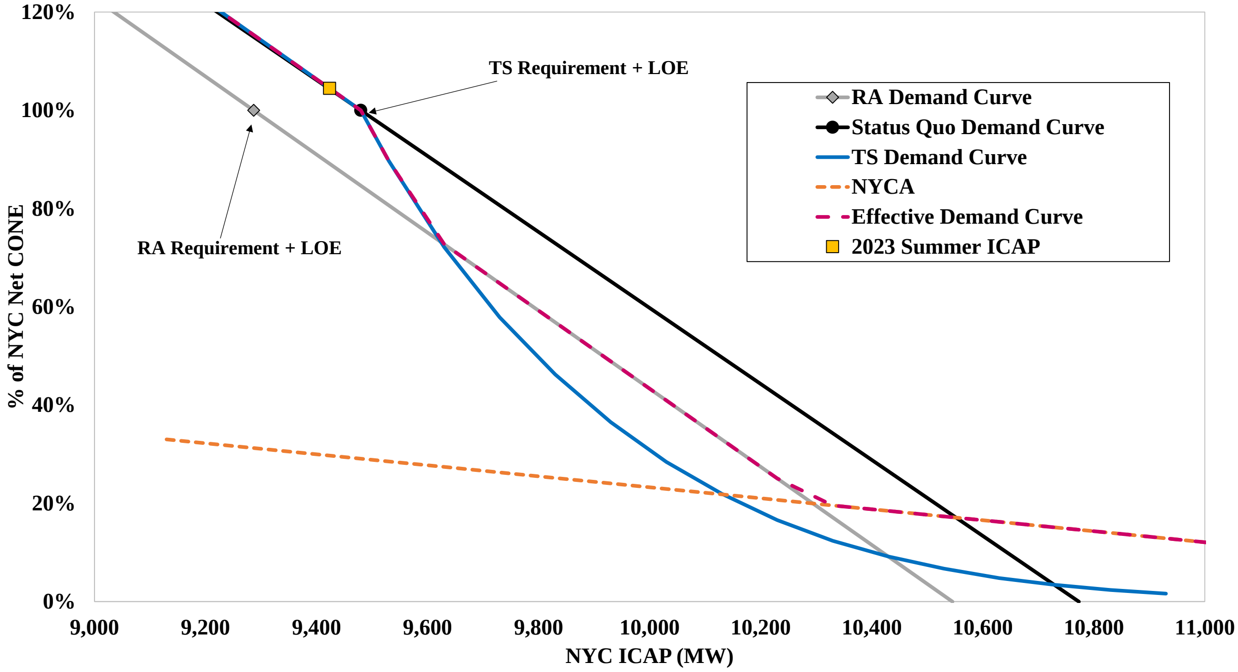
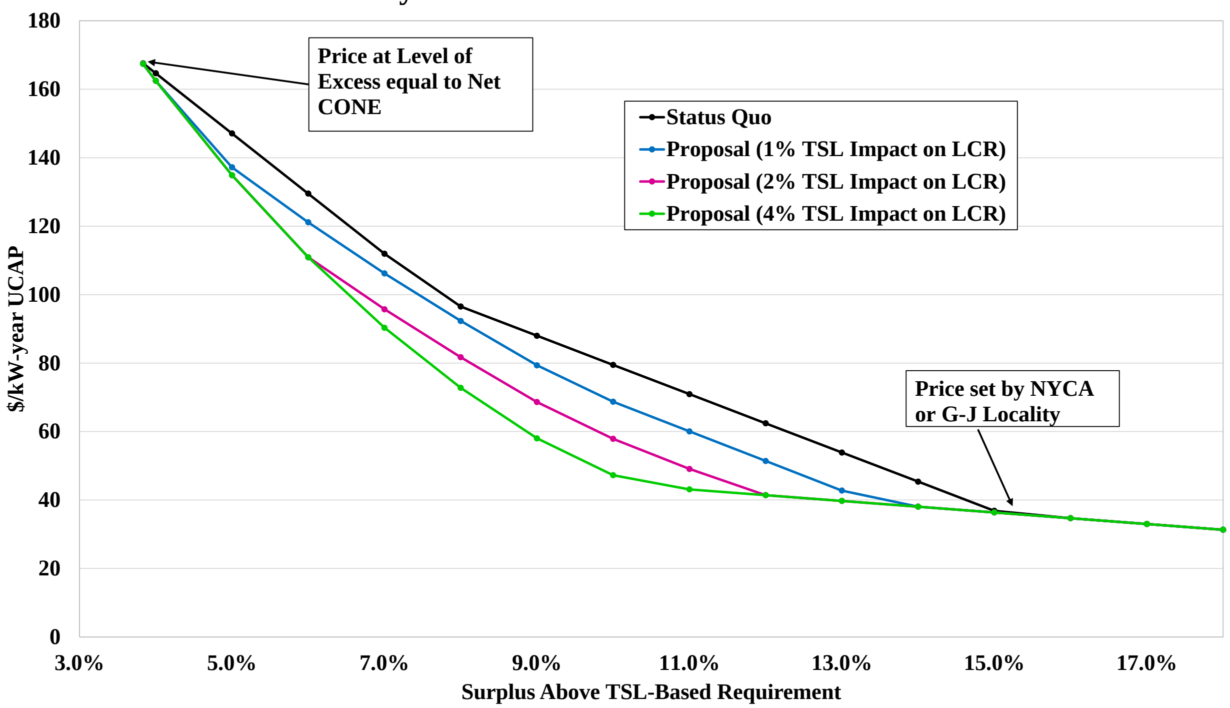


Figure 37 estimates the impact of our proposal on annual New York City capacity prices. We calculated summer and winter capacity demand curves based on the Status Quo, Resource Adequacy and Transmission Security demand curves described above.

Figure 37: Impact of Transmission Security Demand Curve Proposal on Capacity Price New York City 2023/24 TSL and Demand Curve Parameters



For the results shown in Figure 37, we calculate the annual price based on the surplus level indicated on the X-axis in summer and the surplus level times the winter-summer ratio in winter. The magnitude of impact depends on the difference in transmission security and resource adequacy based LCRs. Hence, we compared a Status Quo case (with a sloped demand curve beginning at New York City's current 81.7 percent TSL-based LCR) to a "Proposal" case assuming the RA-based LCR would be 1, 2 or 4 percent lower than the TSL-based LCR.

Figure 37 shows when the Transmission Security requirement is much higher than the Resource Adequacy requirement, surplus capacity is overvalued by the Status Quo demand curve. If the Transmission Security requirement is higher than the RA requirement by 1 to 4 percent, our proposal to price surplus capacity based on its incremental reliability value would lower costs by up to $110 to $311 million per year in New York City, depending on the level of surplus.

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.[159]

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.

159 See Appendix Section VI.H for additional details.

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:

- *Natural gas limitations* – Approximately 7 GW of generation capacity in eastern NYISO can operate only on natural gas and lacks backup fuel capability.[160] 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 2024 Gold Book forecasts that the gap between summer and winter peak load will shrink from 8 GW in the near term to 5.5 GW by 2030. Winter peak load is projected to exceed summer peak load by the mid-2030s.[161]
- *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

160 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.

161 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.

risk in the coming years and have proposed capacity market reforms to encourage generators to secure firm gas supply.[162] 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.[163] 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 modeling and markets that are needed to quantify and value winter reliability.

Improvements Needed to Winter Resource Adequacy Modeling

NYISO's resource adequacy model is a probabilistic simulation of load shedding risk across all hours of the year. It is used to determine key market parameters including the IRM, LCRs and capacity accreditation factors (CAFs). It will also determine the relative summer and winter reference prices of the capacity market demand curves under NYISO's recently filed seasonal reference point proposal.[164] Hence, accurate resource adequacy modeling is critical for the capacity market to correctly signal the amount and type of resources needed for reliability.

In 2023, NYISO and NYSRC developed a white paper proposing an approach to model fuel constraints of gas-only and dual fuel generators during tight winter conditions in the IRM study.[165] NYSRC's five-year work plan also includes efforts to consider realistic modeling of winter load and seasonal emergency assistance from neighboring regions. We support these efforts, which are essential to accurately model winter reliability. However, we highlight the

[162] 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.

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

[164] See NYISO's September 2023, Management Committee presentation, available here. See FERC docket ER24-701-000.

[165] See NYSRC April 3, 2024 Installed Capacity Subcommittee materials, available here.

following areas of improvement which are needed to accurately measure winter reliability risk and synchronize the resource adequacy process with NYISO's capacity market:

- *Firm gas contracts:* Under the proposed modeling approach, gas availability is estimated based on the historical relationship between winter load and gas-fired generation, which doesn't consider generators' firm gas transportation status for the upcoming capability year. Hence, a generator's firm gas transportation choices will not affect modeled winter risk. As a result, capacity market requirements, prices and accreditation factors will not respond to these choices.[166] In order for markets to operate efficiently, prices should reflect suppliers' decisions to sell more or less of the relevant product.[167]
- *Stored fuel inventories:* When gas is scarce in winter, NYISO relies on generation by oil-fired and dual-fuel units. In a period of severe and prolonged cold weather, there is a risk that these units will not have adequate on-site fuel supplies and will be unable to obtain replacement fuel quickly enough. Recent studies by NYISO and the Analysis Group suggest that the amount and replenishment timeframe of stored oil are pivotal to winter reliability during a prolonged severe cold event.[168] The currently proposed modeling framework would discount the capacity of oil-capable units with inventory arrangements allowing for less than 96 hours of operation over six days. A more realistic approach would explicitly model the capacity, consumption, and replenishment of oil inventories.
- *Over-reliance on non-firm LNG:* Imports of liquefied natural gas (LNG) into New England affect the availability of gas to generators in both New York and New England by offsetting demand from gas utilities. The New England gas utilities contract for more LNG supply than they need to serve their customers in a typical winter. As a result, NYISO and ISO-NE generators have historically benefitted from spare LNG that becomes available in a typical winter but for which generators have no contractual rights. The currently proposed modeling approach, which relies on historical levels of gas availability, does not consider the possibility of this uncontracted fuel source being unavailable during weather conditions when reliability risks are greatest.[169]

Figure 38 and Figure 39 show how these modeling issues could affect key market parameters. We used Potomac Economics' resource adequacy tool[170] to simulate the NYISO system for two

166 The individual generator that acquires firm gas may earn higher capacity payments by joining the firm gas capacity accreditation resource class, but overall capacity market prices and CAFs will not be affected.

167 In the long term, NYISO must develop a framework that does not rely on accurate assumptions in the IRM study of generators' fuel arrangements – see discussion of capacity market design later in this subsection.

168 See Analysis Group, "Fuel and Energy Security In New York State", November 2023, available here, and slides 26-33 of NYISO November 29, 2023 presentation "2023-24 Winter Assessment & Winter Preparedness", available here.

169 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.

170 Potomac Economics' resource adequacy tool simulates load shedding and market parameters using an hourly zonal chronological model framework. See Appendix Section VI.E for a description of Potomac Economics' resource adequacy tool and detail in modeling assumptions used in this analysis.

cases (the 2026-27 and 2030-31 capability years using the 2024 Gold Book load forecast) for the following three modeling approaches:

- "Fixed Derate" modeling approach: similar to the current NYISO/NYSRC proposal, oil and dual fuel units are modeled with a reduction in their installed capacity if their initial inventory and replenishment timeframe allows for less than 96 hours of generation, based on responses to NYISO's winter fuel surveys.[171] Historical LNG imports are included.
- "Survey Oil" modeling approach: oil and dual fuel units are modeled at their installed capacity but with limited fuel supplies which are depleted by usage. Plant-specific starting inventory levels and replenishment timeframes are based on generator responses to NYISO's winter fuel surveys.[172] The non-firm gas supply is limited to pipeline imports rather than gas available to the region because of LNG imports to New England and New Brunswick.
- "24-Hour Delay" modeling approach: similar to the "Survey Oil" approach, but it is assumed that oil inventory replenishments in cold weather are delayed by 24 hours to account for winter storm-related delays.

Figure 38 compares the capacity surplus and winter reliability risk under each modeling approach. The capacity surplus is the amount of capacity that can be removed from each case before violating reliability criteria. The winter risk share is the proportion of unserved energy occurring in winter when the system meets reliability criteria. In the 2026-27 case, the capacity surplus is similar across modeling approaches. Notably, winter risk is slightly higher in the Fixed Derate modeling approach than in the oil inventory tracking approaches. This suggests that when there is relatively little risk of fuel shortages, the Fixed Derate modeling approach may actually overestimate winter risk by discounting the capacity of some oil units.

In the 2030-31 case, the modeling approaches yield very different results. The capacity surplus is lower by approximately 700 to 1,900 MW in the Survey Oil and 24-Hour Delay modeling approaches, compared to the Fixed Derate approach.[173] This is because, as winter load increases,

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171 For example, a generator whose fuel survey responses indicates sufficient inventory at the beginning of cold weather to operate for 96 hours across 6 days or a generator whose survey response indicates that replenishment can occur before inventory is depleted would be modeled with no reduction in capacity in our analysis. A generator whose survey indicates that there is not sufficient fuel to operate for 16 hours per day until replenishment can occur is modeled at a derated capacity level proportionate to its ability to operate for 96 hours across 6 days.

172 For example, a generator whose fuel survey indicates 48 hours of fuel at the start of cold weather and a 72 hour lead time for fuel replenishment would be modeled with an initial inventory of 48 hours. Each hour of operation depletes the unit's inventory, and any spent inventory is replenished after 72 model hours. Our model dispatches inventory-limited oil units to meet load using a heuristic approach designed to deploy resources with larger remaining inventories and/or faster replenishment timeframes first.

173 The capacity surplus is higher in the 2030 case because of assumed new resource entry pursuant to state policy goals. In practice we would expect much of this surplus to retire due to the impact on market prices. These results are intended to illustrate the impact of modeling choices and should be considered comparatively, rather than as an assessment of future system reliability.

the demand that must be served by stored oil grows while existing tank sizes do not, leading to lower winter reliability in the cases that consider oil inventory depletion. Winter risk makes up 80 to 97 percent of total risk in the oil inventory modeling approaches, but only 38 percent in the Fixed Oil Derate approach. These results suggest that as winter load grows due to electrification, the Fixed Derate modeling approach may materially underestimate the amount of capacity needed for reliability and the portion of risk occurring in winter.

Figure 38: Capacity Surplus and Seasonal Risk Under Alternate Modeling Approaches

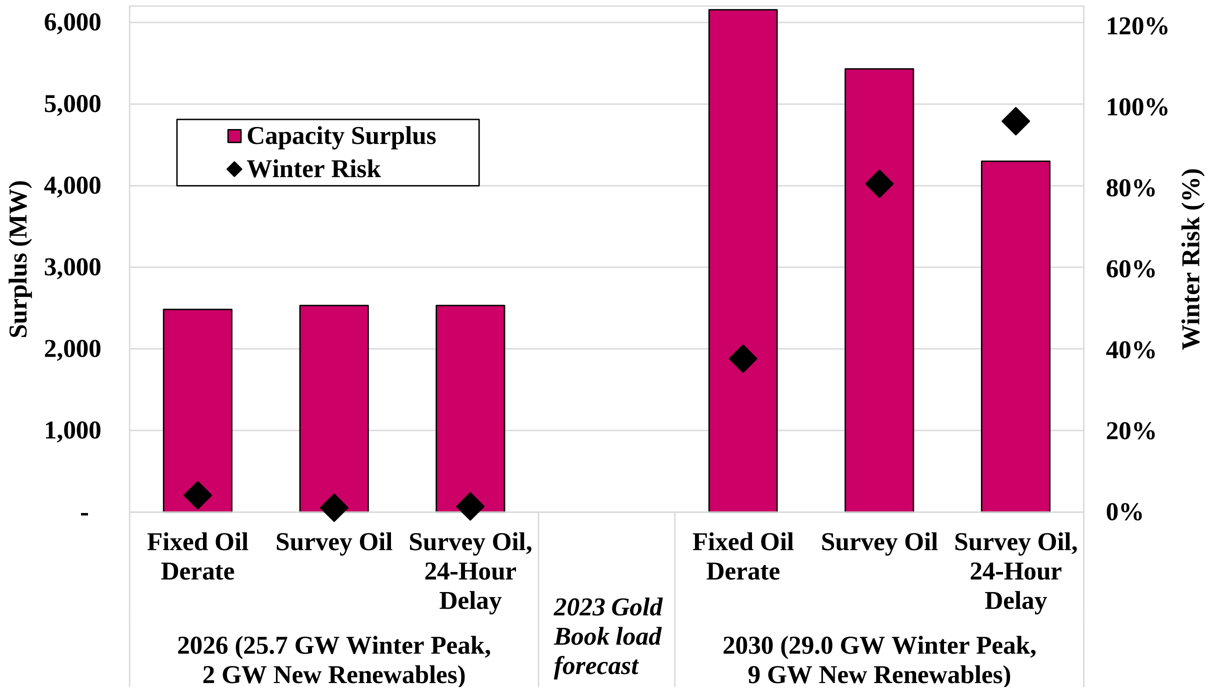
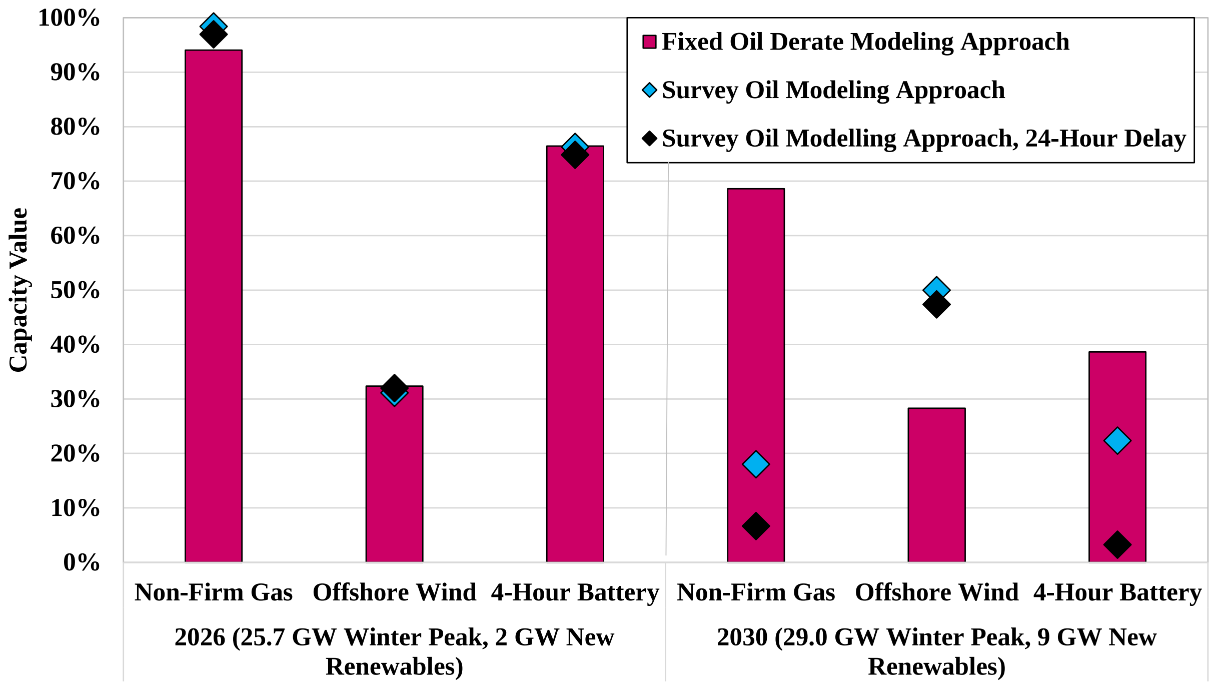


Figure 39 shows the marginal capacity value of non-firm gas generators, offshore wind and 4-hour batteries under each modeling approach. Marginal capacity value measures a resource's effectiveness at improving reliability across all hours of the year, relative to capacity that is always available. This analysis shows that the capacity value for land-based wind and batteries diverges significantly by 2030-31 between the Fixed Derate and inventory tracking modeling approaches. This is because the inventory tracking approaches capture each resource's contribution to winter reliability needs driven by fuel scarcity:

- Non-Firm Gas: The marginal capacity value of non-firm gas is closely related to the amount of winter risk, since non-firm gas generators provide much less marginal benefit in winter. By 2030-31, the Fixed Derate modeling approach significantly overestimates the marginal capacity value of non-firm gas because it underestimates winter risk. As a result, gas-only generators have weak incentives to acquire contracts for firm fuel in the Fixed Derate approach and strong incentives in the inventory tracking approaches.
- Offshore Wind: Wind resources have much higher marginal value under the inventory tracking approach because their output helps to defer consumption of stored fuels across the entire cold period, even if their output during the net peak load hour is low.

- 4-Hour Storage: Battery storage has lower marginal value in winter under the inventory-tracking approaches because the battery cannot be recharged without additional depletion of stored fuel from oil units.

Figure 39: Annual Capacity Value Under Alternate Modeling Approaches



These results indicate that as the risk of winter fuel shortages grows, the Fixed Derate modeling approach will inaccurately model winter reliability risk. This will result in requirements, prices, and CAFs that undervalue winter fuel security. As a result, the Fixed Derate approach will send inaccurate signals to resource owners, developers, and state agencies regarding the value of decisions such as whether to obtain firm gas transportation, whether to maintain or retire gas-only or dual fuel generators, and which clean energy resources provide the most reliability benefit. Hence, we recommend NYISO develop realistic resource adequacy modeling approaches for inventory-limited resources in winter (Recommendation 2021-4a).

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 (the "Annual Study Approach"):

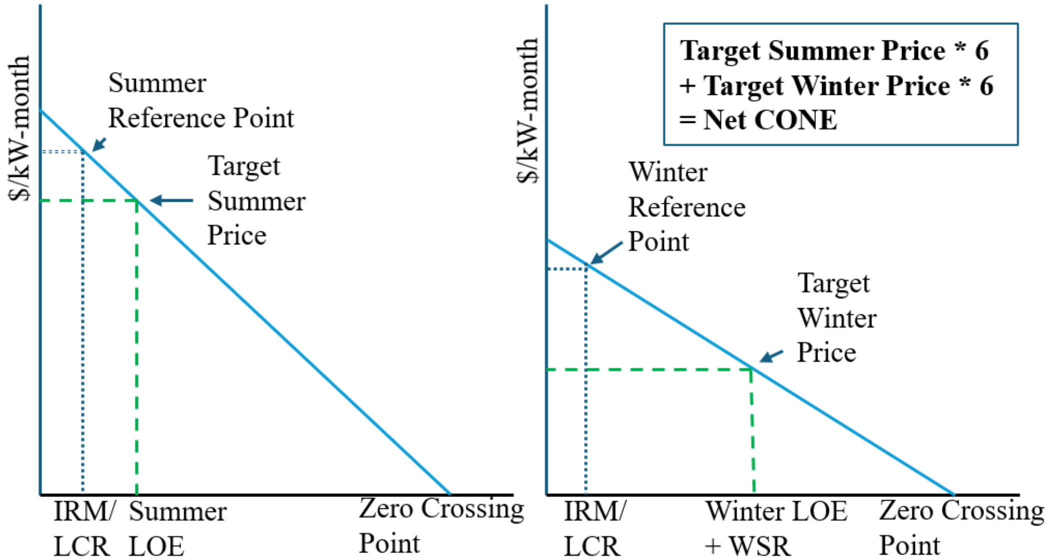
- *ICAP Requirements* – A single annual set of ICAP requirements based on the Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) apply to all months of the year. These are determined by resource adequacy model studies conducted in the year prior to the corresponding capability 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* – Under recently filed changes, separate summer and winter demand curve reference prices will be 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 40 illustrates how summer and winter reference points are determined under the NYISO's seasonal reference point proposal. Reference points are chosen so that the demand curve reference unit 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").

NYISO recently developed changes to the accreditation of gas and oil units in eastern New York based on their winter fuel arrangements.[174] 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 demonstrate firm gas pipeline transportation contracts or sufficient stored inventory to operate for 96 hours across a six-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.

174 See NYISO March 27, 2024 Management Committee presentation "Modeling Improvements for Capacity Accreditation", available here.

Figure 40: NYISO Seasonal Reference Point Proposal
Assuming Higher Summer Risk in IRM/LCR Study



2. Analysis of Current Design Shortcomings

The seasonal capacity market framework (including the seasonal reference point and winter fuel accreditation provisions discussed above which will be implemented in the 2025-26 Capability Year) has already improved over the historic design, in which winter prices bore no relationship to winter reliability risk. However, the capacity market will still rely on an annual approach to setting key market parameters that lacks the flexibility to respond to seasonal variations in available capacity. Without additional market reforms to reflect seasonality as winter risk grows in the coming years, the capacity market is likely to produce prices and CAFs that are excessively volatile and misaligned with the system's needs.

The current framework will produce prices and CAFs that accurately reflect seasonal reliability only if the seasonal resource mix assumptions of the IRM/LCR study are accurate. Historically, the IRM/LCR study has only needed to predict summer installed capacity in practice and has had a high degree of accuracy. This is because new generator construction and retirements are usually signaled far enough in advance to be considered in the IRM/LCR study. To the extent that the actual resource mix differed from the study assumptions due to factors such as changes in import levels or unplanned generator outages, the capacity market could respond to such changes by moving along the capacity market demand curves. For example, if a generator unexpectedly does not sell capacity due to an outage, prices would increase (because less UCAP is sold) but there would not be a large impact on the accuracy of the requirements and CAFs.

As winter reliability needs grow, key supply factors that affect winter risk will be much more difficult to predict because they are driven by short-term market conditions that could change significantly after the IRM/LCR study is finalized, including:

- *Firm fuel* – generators' firm fuel arrangements may differ from the assumptions used in the IRM/LCR study by the corresponding winter capability period. This may occur because generators failed to obtain the firm fuel arrangements they originally elected, or because generators chose to acquire firm fuel beyond their original election.[175] Currently proposed rules require generators to make fuel elections approximately 16 months before the corresponding peak winter months, but gas transportation contracts are often arranged much closer to the associated winter.
- *Net Imports* – Capacity imports and exports vary seasonally and are not known in advance. For example, NYISO had net capacity *imports* of almost 800 MW in July and August of 2023 and net *exports* of 900 MW in January and February of 2024, a seasonal difference of almost 1,700 MW. The IRM study does not model the seasonal net import patterns observed in the capacity market, which are not necessarily associated with long-term capacity commitments. The 2024/25 IRM study assumed net capacity *purchases* of 1,938 MW in all months of the year (compared with the 900 MW of net *sales* observed in January and February of 2024).

Firm fuel arrangements and net imports are challenging to predict in advance because they are price-sensitive and likely to change in response to market parameters. High winter prices and high firm CAF premiums (i.e. the incremental value of the firm CAF over the non-firm CAF) will tend to attract more seasonally variable winter resources. Low winter prices and low firm CAF premiums will tend to attract less of these resources. Hence, setting reference point prices and CAFs based on seasonal assumptions of the IRM/LCR study may cause market participants to respond in ways that render those assumptions inaccurate.

Additionally, the inflexibility of the current framework sends poor incentives for gas and dual fuel resources to respond appropriately to market signals through fuel procurement decisions. Elections to the firm or non-firm CARC cannot be changed after their initial selection 16 months in advance. As a result, if the IRM/LCR study finds elevated winter reliability risk, non-firm resources cannot subsequently increase their capacity payments by acquiring firm fuel to alleviate that risk. Since generators will not know the capacity price, CAFs, or gas transportation costs by the election deadline, they may be risk-averse and procure less than the optimal amount of firm fuel. Finally, when the firm CAF premium is low or zero, generators that elected to be firm may have incentives to renege on their commitments (since the incremental benefit of firm fuel supply would not justify the cost), but market parameters would not recognize the resulting increase in winter risk.[176]

175 As discussed earlier in this subsection, NYISO's current IRM modeling proposal would not represent firm gas transport elections at all but would instead model historical gas availability from generators with both firm and non-firm gas. Firm gas availability modeled in MARS is likely to differ from *actual* firm gas procurements under either this approach or an approach of modeling generators' elections.

176 Under the NYISO's proposal, the penalty for failing to demonstrate firm fuel by the start of the winter capability period is based on the difference between the firm and non-firm CAFs. If the firm and non-firm CAFs are close in value, the value of this penalty will be very small or zero.

Figure 41 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. But under the current design, generators would lack incentives to acquire firm gas (because they cannot move from the non-firm to firm CAF) and any acquisition of firm gas 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.

Figure 41: Potential Market Outcomes Under Current Seasonal Framework

	Example 1	**Example 2**
IRM/LCR Study Result	High winter risk in IRM/LCR study	Winter risk underestimated in IRM/LCR study
Market parameters	High/steep winter demand curve, high firm CAF premium	Low/flat winter demand curve, low firm CAF premium
Market participant response	Generators acquire more firm fuel	Winter imports fall and/or exports rise
Market Impact: Ideal Impact	Winter price and firm premium fall due to lower winter risk	Winter price rises to prevent excessive loss of net imports
Market Impact: Impact in current design	No impact; winter price and firm CAF premium remain high	Small increase in price, firm CAF premium remains low

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.
- *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. 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.[177]

  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.[178]

Figure 42 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.

The proposed approach has the following advantages:

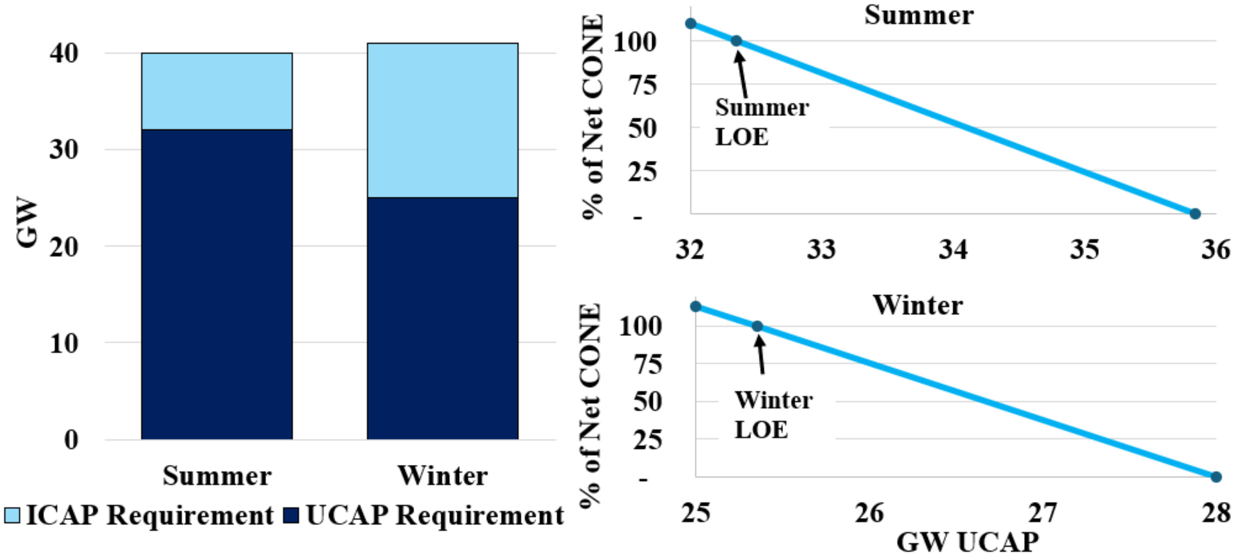
- It does not rely on accurate assumptions regarding relative summer and winter risk in the IRM/LCR study;
- It does not rely on ICAP Winter-Summer Ratio to set demand curves;

[177] 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. 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.

[178] 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.

- 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.

Figure 42: Illustration of Requirements and Demand Curves Under Seasonal Proposal



4. Near-term enhancement to avoid extreme market outcomes caused by winter summer ratio calculation

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) 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.

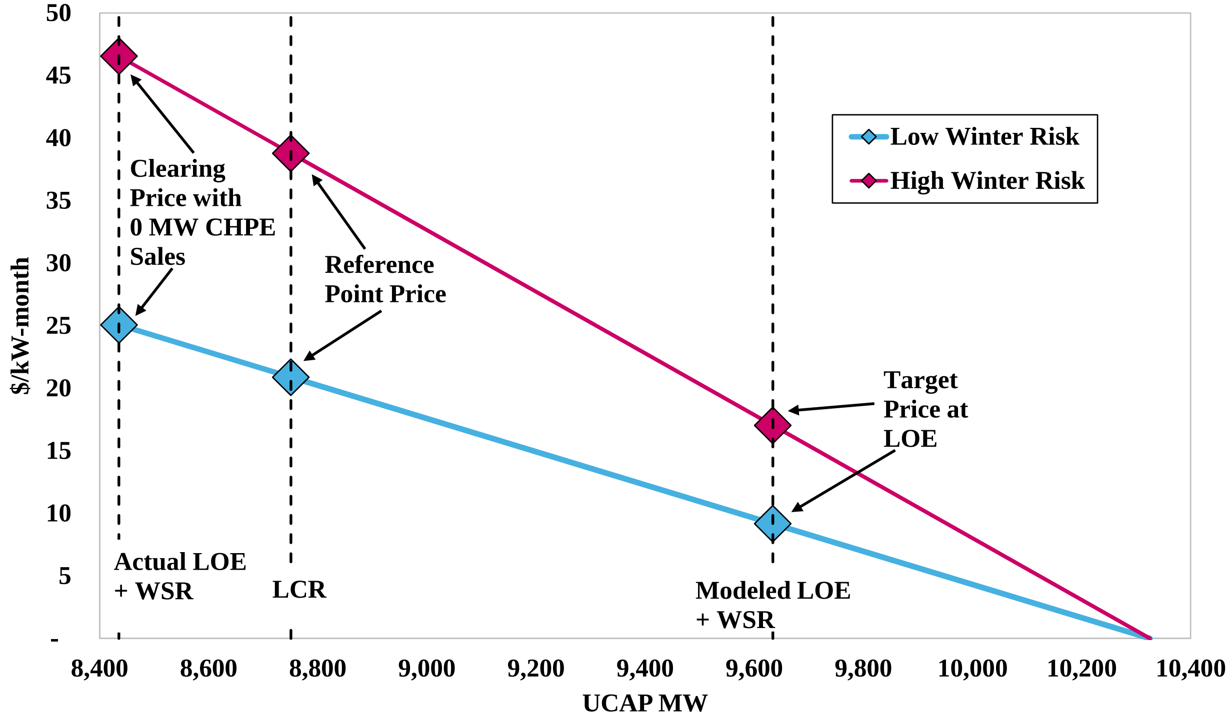
Many thermal generators have higher capability in winter than in summer. Hence, since the ICAP requirements are the same in all months, there is typically more surplus ICAP in winter than in summer. When the NYISO sets the demand curve reference points, it takes into account that the auction will clear 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.[179] 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 43 shows estimated winter demand curves for New York City with CHPE in service, using 2024/25 parameters and NYISO's seasonal reference point proposal.[180]

Figure 43: Illustration of Extreme Pricing Risk Due to WSR Calculation



For the analysis shown in Figure 43, 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

179 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).

180 The risk highlighted in this subsection would be present in the absence of NYISO's recently field seasonal reference point proposal, because the historic process for setting reference points also relies on the WSR.

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 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 43 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) and not reliability fundamentals.

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. 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.

5. 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);
- 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; and
- Develop realistic resource adequacy modeling approaches for inventory-limited resources in winter (Recommendation 2021-4a)

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 who would otherwise be limited to higher-cost resources in another area; and
- NYISO to draw on neighboring systems for emergency power, reserves, and capacity, which help lower the costs of meeting reliability standards in each control area.

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 connect directly to PJM and New England across six controllable lines that are collectively able to import up to roughly 2.7 GW directly to downstate areas.[181] Hence, NYISO's total import capability is large relative to its load, making it important to schedule the interfaces efficiently.

This section provides a summary of interchange patterns between New York and neighboring control areas in recent years in subsection A, and the performance of Coordinated Transaction Scheduling with ISO New England and PJM in subsection B.

A. Interchange between New York and Adjacent Areas

Table 10 summarizes the net scheduled imports from neighboring control areas from 2018 through 2023 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[182]

Table 10: Average Net Imports from Neighboring Areas
Peak Hours, 2018 – 2023

Year	Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2018	1,372	733	442	-564	164	561	30	201	253	3,192
2019	1,327	686	492	-810	155	610	37	224	179	2,900
2020	1,258	750	367	-965	89	509	52	179	164	2,403
2021	1,317	585	699	-586	228	313	90	256	332	3,236
2022	1,137	471	459	-392	217	483	62	275	376	3,088
2023	440	377	735	-485	171	630	68	264	413	2,613

181 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.

182 Figure A-60 to Figure A-63 in the Appendix provide additional details.

In 2023, average total net imports from neighboring areas was approximately 2.6 GW in peak hours, which was a decrease of 15 percent from the previous year. However, imports still served a significant portion (14 percent) of NYISO load during peak hours in 2023.

Controllable Interfaces to New York City and Long Island

On Long Island, net imports from neighboring control areas satisfied over 36 percent of demand in peak hours of 2023, which was 3 percent higher than the 2022 level. The increase was driven primarily by the status of the Neptune Line which had been partially unavailable for the much of the first half of 2022 but experienced no lengthy periods of unavailability in 2023.

In New York City, net imports over the HTP and Linden VFT lines contributed a total of 680 MW during peak hours in 2023, satisfying 11 percent of the peak hours demand. Imports over the HTP line increased for a third year in a row with the highest levels observed in both the peak winter and summer months. Natural gas prices in northern New Jersey exhibited a persistent discount relative to pricing hubs on other pipelines serving the northeast, providing incentives to flow more low-cost imports from PJM to New York City.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces fell 36 percent from 2022 to 1,066 MW in 2023 in peak hours, the lowest level observed for several years. This decrease was largely due to reductions in imports from both Canadian control areas, especially along the Quebec interface. Increased net exports to New England (which was also affected by the reduction in imports from Canada) further contributed to the decline, but a 276 MW increase in imports from PJM helped offset these reductions.

Among the primary interfaces, the Quebec interface historically accounted for the largest share of net imports. Net imports averaged just 440 MW in peak hours from Quebec, down more than 60 percent from 2022 levels. Extensive wildfires across many Canadian provinces began in March 2023, affecting generation and transmission in Quebec. Consequently, net import levels fell each month from March (1.3 GW) to August (0.1 GW) and overall net flows shifted to the export direction by November.

Although the Ontario province may have been less directly impacted by the wildfires, net imports along the interface fell by 20 percent from 2022 levels. This was the third consecutive year of declining imports to New York from Ontario, which accounted for 700 MW or more of average imports prior to 2021. Net imports to Ontario from other areas were down almost 50 percent, which required increased utilization of gas-fired generation.[183] The resulting increase in prices led to reduced flows into Western New York.

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[183] See IESO Year End Data report at https://www.ieso.ca/Corporate-IESO/Media/Year-End-Data.

Net imports across the primary interfaces with PJM and New England largely followed the changes in gas price spreads between these regions. For example, in the winter, New York normally imports from PJM and exports to New England, consistent with the gas price spreads between markets during this season (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.

B. Coordinated Transaction Scheduling with ISO-NE and PJM

Coordinated Transaction Scheduling (CTS) allows two neighboring RTOs to exchange and use real-time market information to clear market participants' intra-hour external transactions more efficiently. CTS has at least two advantages over the hourly LBMP-based scheduling system that is used at the interfaces with Ontario and Quebec and between Long Island and Connecticut.

- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.
- CTS schedules transactions much closer to the operating time. Hourly LBMP-based schedules are established up to 105 minutes in advance, while CTS schedules are determined less than 30 minutes ahead when better information is available.

It is important to evaluate the performance of CTS on an on-going basis to ensure that the process is working as efficiently as possible. In this subsection, we discuss several factors that have affected CTS performance at the PJM and ISO New England interfaces, particularly the effects of transaction fees and short-term price forecasting. We also provide a detailed analysis of factors that contribute to poor short-term price forecasting.

1. Evaluation of CTS Bids and Profits

Under CTS, traders submit bids that are scheduled if the RTOs' forecasted price spread is greater than the bid price, so the process requires a sufficient quantity of price-sensitive bids. Figure 44 evaluates the price-sensitivity of bids at the primary PJM and ISO-NE interfaces, showing the average amount of bids at each interface in peak hours (i.e., HB 7 to 22) from 2020 to 2023.[184] 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.[185]

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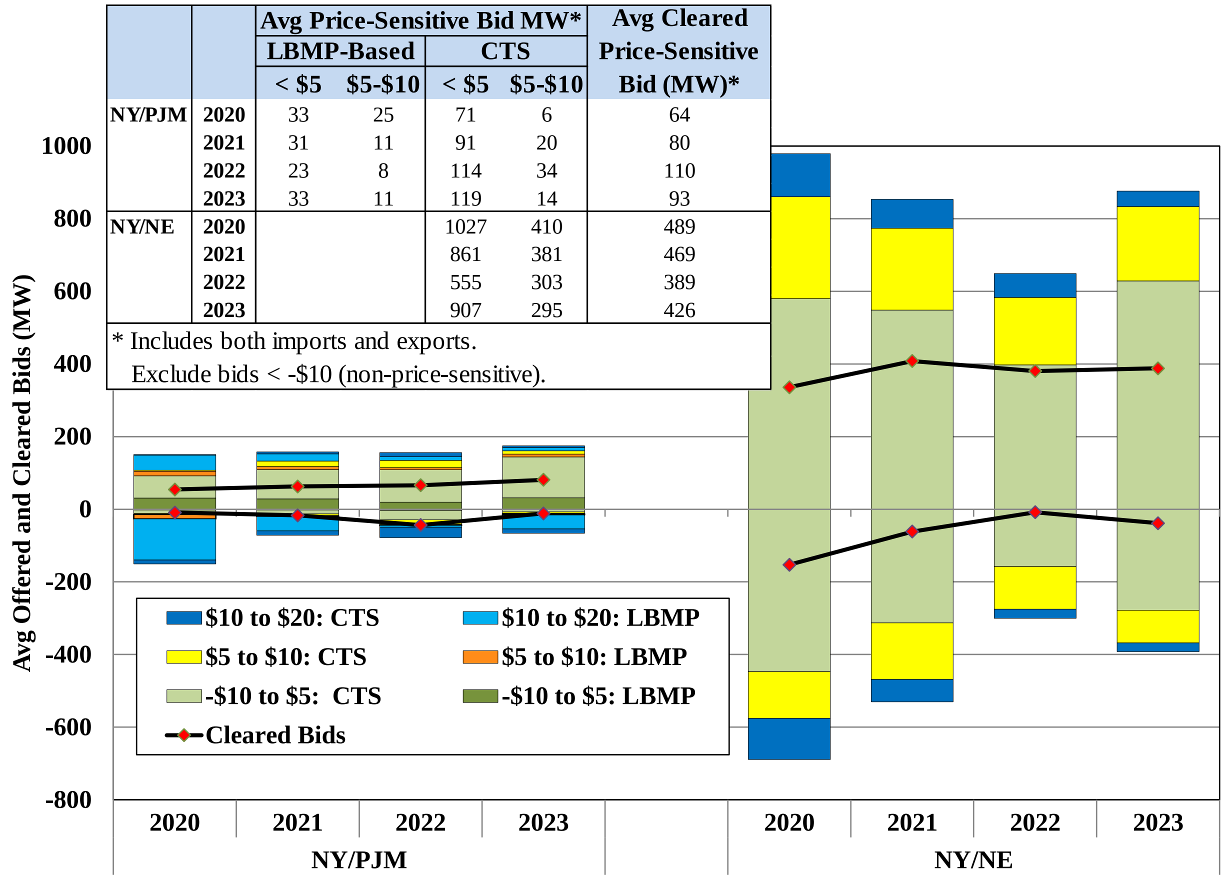
184 Figure A-65 in the Appendix shows the same information by month for 2022.

185 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.

Figure 44: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2020-2023



		Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
		LBMP-Based		CTS		
		< $5	$5-$10	< $5	$5-$10	
NY/PJM	2020	33	25	71	6	64
	2021	31	11	91	20	80
	2022	23	8	114	34	110
	2023	33	11	119	14	93
NY/NE	2020			1027	410	489
	2021			861	381	469
	2022			555	303	389
	2023			907	295	426

* Includes both imports and exports.
Exclude bids < -$10 (non-price-sensitive).

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 2023. An average of roughly 1185 MW (including both imports and exports) was offered between -$10 and $5 per MWh at the New England interface over this four-year period, substantially higher than the 160 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 five-times the average amount cleared at the PJM interface over this four-year period.

The differences between the two CTS processes are largely attributable to the large fees that are imposed at the PJM interface, while there are no substantial transmission charges or uplift charges on transactions between New York and New England. NYISO typically charges physical exports to PJM at a transmission rate ranging from $5 to $8 per MWh, so very few CTS export bids were offered at less than $5 per MWh at the PJM border. On the other side, PJM charges physical imports and exports a transmission rate that averages less than $2 per MWh.[186]

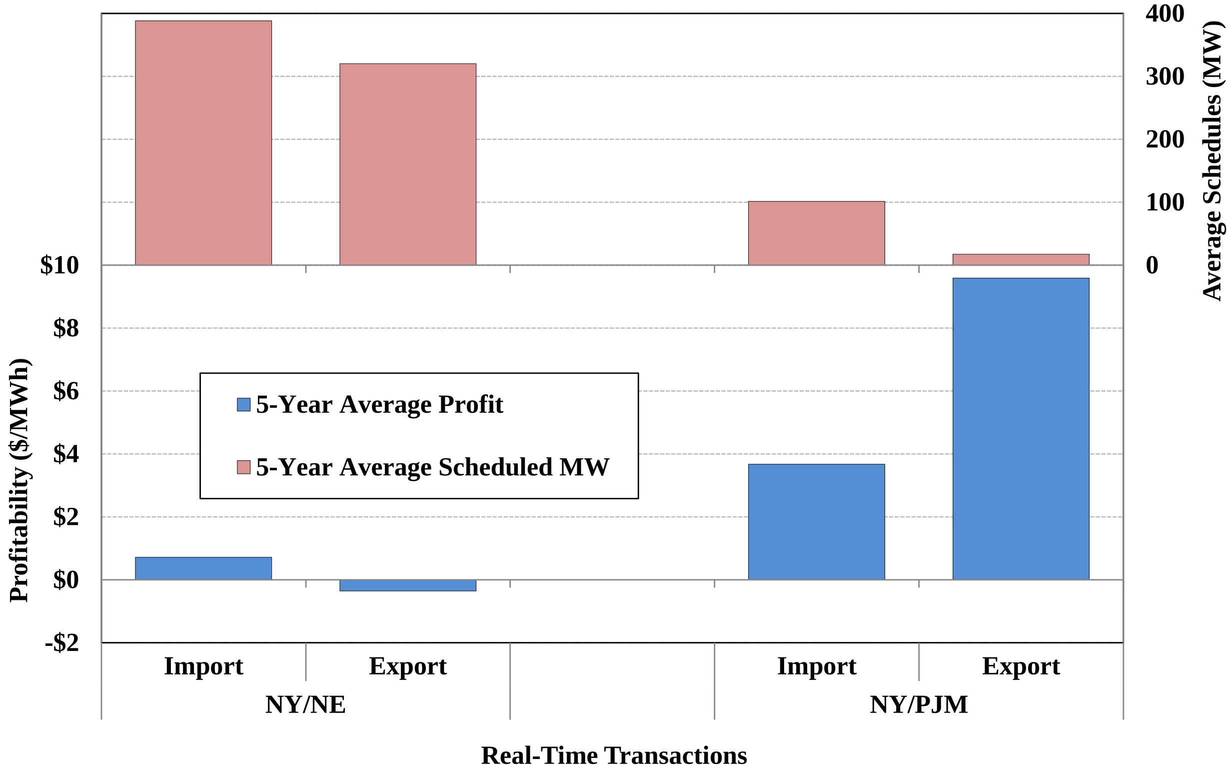
186 Although PJM increased its Transmission Service Charge substantially to firm imports/exports to $6.34/MWh in 2020, it kept the charge to non-firm transactions (including CTS transactions) at a low level of

These charges are a significant economic barrier to achieving the potential benefits from the CTS process at the PJM border.

Figure 45 examines the average gross profitability of scheduled real-time transactions (not including fees mentioned above) and average scheduled quantity at the two CTS interfaces from 2019 to 2023.[187] The gross profitability of scheduled real-time transactions (including both imports and exports) averaged roughly $0.61 per MWh over the five-year period at the primary New England interface, indicating this is generally a low-margin trading activity because firms are willing to schedule when they expect even a small price differential.

Figure 45: Gross Profitability and Quantity of Scheduled Real-Time External Transactions

PJM and NE Primary Interfaces, 2019-2023



At the PJM border, scheduled imports had a significantly higher average gross profitability, while scheduled exports had an even higher profitability. This reflects that market participants only schedule transactions when they expect the price spread between markets to be large enough to recoup the fees that they will have to 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

$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.

187 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).

trading provides a strong disincentive to schedule transactions, dramatically reducing trading volumes, liquidity, and even revenue collected from the fees.

We recommend eliminating (or at least reducing) these charges at the interfaces with PJM for several reasons.[188] First, as the resource mix in New York changes to include more intermittent renewable resources, it will be important to schedule exports to neighboring regions when excess renewable generation cannot be delivered to consumers in New York. A better-performing CTS will facilitate more efficient scheduling between markets, which is important for successful integration of these resources. High fees will lead to more frequent periods when renewable generation will be curtailed because it cannot be delivered to consumers.

Second, it is unreasonable to assign the same transmission charges to price-sensitive exports as are assigned to network load customers. These transmission charges recoup the embedded cost of the transmission system which is planned for the projected growth of network load, but price-sensitive exports likely contribute nothing to the cost of the transmission system.

Third, we estimate that NYISO collected roughly $0.70. million in export fees from real-time exports to PJM in 2023, while PJM collected $2.9 million in export fees from real-time exports to NYISO. Thus, it is possible that a lower export fee would lead to higher overall collection of fees because it would allow CTS transactions to be profitable under a wider range of conditions.

2. Evaluation of CTS Production Cost Savings

We also performed a more general assessment of the savings produced by the CTS processes at both interfaces, which depend primarily on the accuracy of the RTOs' price forecasts and the charges assessed to the CTS transactions.[189] The potential savings in production costs were generally higher at the New England interface because the higher liquidity of bids at that interface contributed to larger and more frequent intra-hour interchange adjustments. In 2023, this adjustment (from our estimated hourly schedule) occurred in 87 percent of intervals at the New England interface, compared to 49 percent at the PJM interface. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that in 2023,[190]

- $6.6 million of savings were realized at the New England interface; and
- Around $10 thousand were realized at the PJM interface.

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188 See Recommendation 2015-9.

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

190 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.

In 2023, actual production cost savings at the New England interface decreased from 2022 because of smaller disparities in energy prices between the markets, which were partly driven by lower gas price spreads. This is true of the actual production cost savings at the PJM interface, however, the savings in general tend to be low there making annual changes small in magnitude. Production cost savings at the PJM interface were significantly lower than at the New England interface, which has been a persistent trend in recent years, partly attributable to relatively large price forecast errors. At the two CTS interfaces, the price forecasts produced by PJM were far less accurate than those produced by NYISO and ISO New England in recent years.

The efficient performance of CTS depends on the accuracy of price forecasting, so it is important to evaluate market outcomes to identify sources of forecast errors. The remainder of this subsection summarizes our analysis of factors that contributed to forecast errors by the NYISO.

3. Evaluation of RTC Forecasting Error

RTC schedules resources (including external transactions and fast-start units) with lead times of 15 minutes to one hour. Inconsistency between RTC and RTD prices is an indicator that some scheduling decisions of RTC may be inefficient. We have performed a systematic evaluation of factors that led to inconsistencies between RTC and RTD prices in 2023. This evaluation measures the contributions of individual factors in each pricing interval to differences between RTC and RTD, and this allows us to compare the relative significance of factors that contribute to forecast errors over time. We expect that this evaluation will be useful as the NYISO and stakeholders prioritize different projects to improve market performance.

Figure 46 summarizes the RTC/RTD divergence metric results for “detrimental” factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2023. Our evaluation found that the factors that contributed most to RTC price forecast errors in 2023 were mostly consistent with prior years.[191] We discuss each of these factors in more detail below.

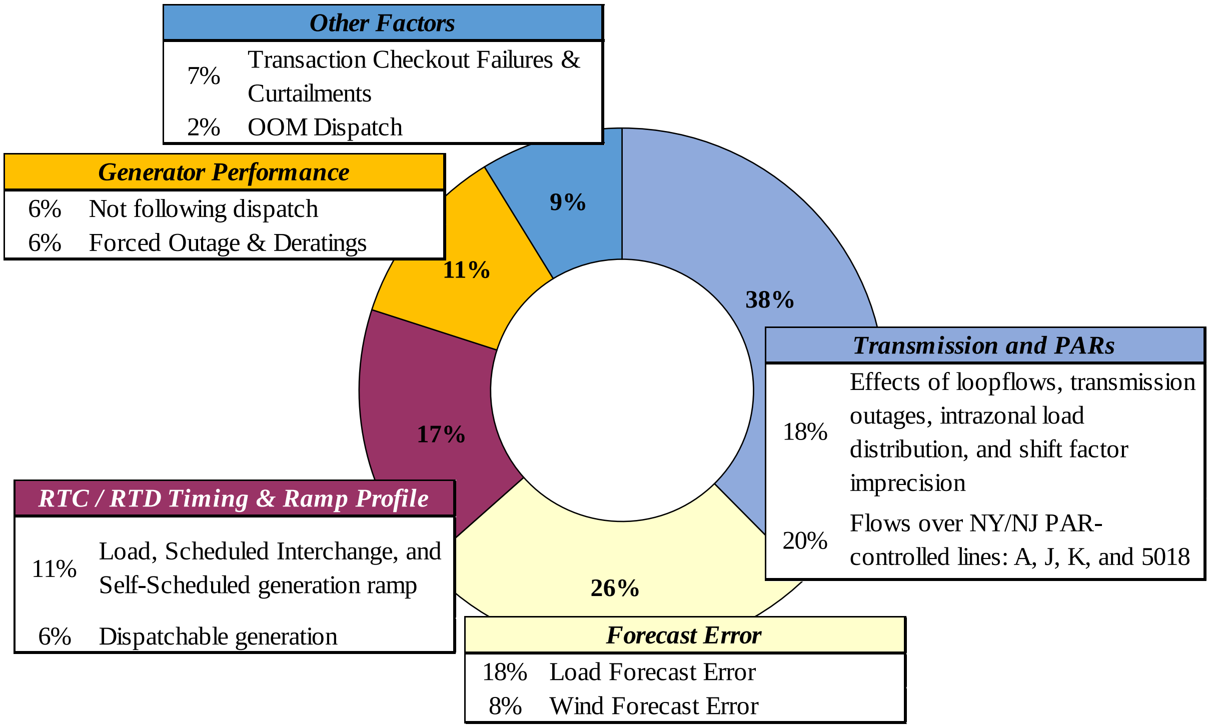
First, transmission network modeling issues were the most significant category, accounting for 38 percent of divergences between RTC and RTD in 2023. In this category, key drivers include:

- Variations in the transfer capability available to NYISO-scheduled resources that result primarily from: (a) transmission outages; (b) changes in loop flows around Lake Erie and from New England; (c) inaccuracies in the calculation of shift factors of NYISO units, which are caused by the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch; and (d) variations in the distribution of load within a zone.
- Errors in the forecasted flows over PAR-controlled lines between the NYISO and PJM (i.e., the 5018, A, and JK lines), which occur primarily because the RTC forecast: (a) does not have a module that predicts variations in loop flows from PJM across these

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

lines, (b) assumes that no PAR tap adjustments are made to adjust the flows across these lines, and (c) assumes that NYISO generation re-dispatch does not affect the flows across these lines although it does.

Figure 46: Detrimental Factors Causing Divergence Between RTC and RTD
2023



Second, errors in load forecasting and wind forecasting were also large contributors to price differences between RTC and RTD, accounting for 26 percent of the overall divergence between RTC and RTD in 2023.[192] Although the contribution of the load forecast error fell modestly from the level recorded in 2022, it remained high compared to previous years. During the period from hour 10 to hour 18, the average RTC forecasted load was approximately 85 MW higher than average RTD load, contributing to a $1.5 per MWh difference between average RTC LBMPs and RTD LBMPs during the same period.[193] The operator's adjustments to the RTC load forecast were a significant driver of the load difference between RTC and RTD

Third, the next largest category, which accounted for 17 percent of the divergence between RTC and RTD prices in 2023, was related to inconsistencies in 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

192 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.

193 See Figure A-76 in the Appendix for more details.

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 (five minutes later than RTC).[194] We have recommended improving the consistency between the ramp assumptions used in RTC and RTD.[195]

Fourth, external transaction curtailments and checkout failures accounted for 7 percent of detrimental factors to RTC/RTD price convergence in 2023, lower than the 14 percent in 2022 yet still much higher than the 2 to 4 percent observed in prior years.

In 2023, substantial quantities of external transactions were scheduled by RTC but subsequently cut or curtailed. This includes roughly:

- 269 hours when an average of 203 MW of imports were cut from Ontario, primarily because imports to NYISO are often submitted as price-sensitive export bids on the Ontario side and cut in Ontario's economic evaluation. This includes direct imports from Ontario to NYISO and wheels through Quebec to NYISO.
- 49 hours when an average of 180 MW of imports were cut from Quebec, primarily because TransEnergie did not identify transmission bottlenecks within its footprint until after the transactions were scheduled by RTC.
- 97 hours when an average of 276 MW of imports were cut from PJM, mainly for its internal system security.
- 44 hours when an average of 281 MW of imports were cut from New England, primarily because ISO-NE identified potential capacity deficiencies after the transactions were scheduled by RTC.

For its part, NYISO cut or curtailed an average of 230 MW of imports and/or exports in a total of 137 hours, primarily to manage internal transmission security constraints on facilities not secured in the day-ahead and real-time market models.

In many cases, curtailments simply lead RTD to increase production from internal generation at a modest additional cost. However, in tight conditions, RTC may schedule low-cost imports and consequently pass on the opportunity to commit peakers.[196] The mild winter and summer weather conditions across the year muted the frequency and impact of such situations in 2023.

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

195 See Recommendation 2012-13.

196 Ordinarily, firms schedule power flow between control areas by submitting an import offer to NYISO up to 75 minutes ahead of the scheduling hour and an export bid in the source area in accordance with its bidding timeline. RTC determines hourly imports 45 minutes before the hour begins, while 15-minute imports are determined 15 minutes before each 15-minute period begins. Additionally, RTC determines start-up and shut-down instructions for 10-minute and 30-minute peaking units 15 and 30 minutes before each 15-minute period begins. RTC routinely schedules low-cost imports rather than more-expensive internal peaking units.

However, this was a prominent problem that contributed to volatile pricing and tight conditions during the cold spell of December 2022.[197]

If the import is subsequently curtailed by the neighboring control area, it sometimes requires NYISO to deploy more expensive peakers that are available on short notice and/or go short of contingency reserves if resources are not available on short notice. It would be useful to consider ways to ensure that NYISO does not rely on imports that are likely to be curtailed after the RTC evaluation. Relying on such curtailable imports might be reasonably economic when NYISO has the operating reserves to cover a curtailed import, but not when the curtailment would lead to NYISO reserve shortages.

Addressing 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, the resource mix of New York is changing away from traditional fossil-fuel generation towards: (a) intermittent renewable generation that will increase uncertainty of resource availability in real time, and (b) new types of peaking generators and energy storage resources that must be deployed based on a short-term forecast 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.

197 For more on that event, see our 2022 State of the Market Report.

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 2023 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;
- 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

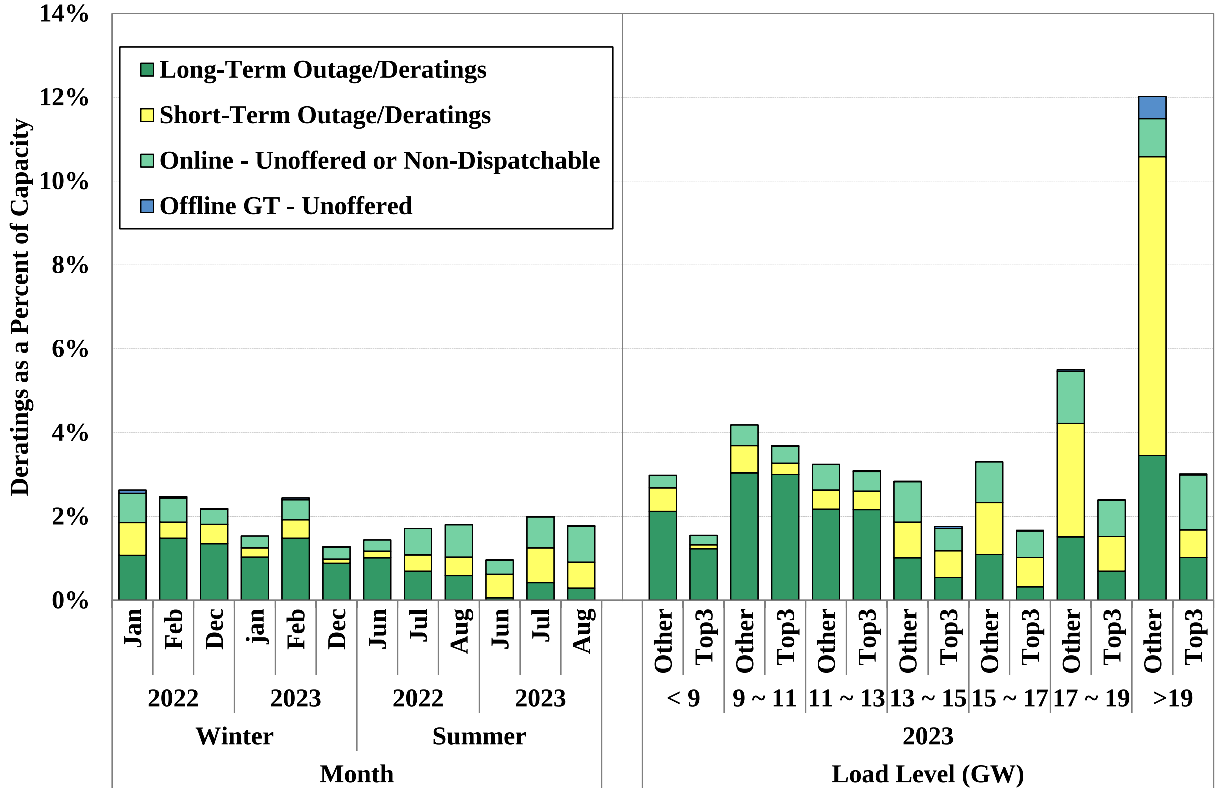
In a competitive market, suppliers have strong incentives to offer their supply at prices close to their short-run marginal production costs. Fuel costs account for the majority of short-run marginal costs for most generators, so the close correspondence of electricity prices and fuel prices is a positive 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 47 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 48 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.[198]

[198] 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 47: Unoffered Economic Capacity in Eastern New York
2022 – 2023



Overall levels of unoffered economic capacity remained low in 2023, similar to prior years. However, short-term outages and deratings averaged nearly 8 percent of total capacity during high load conditions, with most issues arising among the smaller portfolios. Loads were low in 2023, which reduced the number of hours in the high load ranges. Most (61 percent) of the capacity flagged for short-term outages and derates in peak hours was on conventional steam units in Eastern New York. After the retirement of downstate peaking capacity following the summer of 2022, some older more outage-prone steam turbines have been scheduled to operate more frequently in high load hours.

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 half 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.[199] 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.[200]
- *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 2023, averaging 0.05 percent of total capacity at the statewide mitigation threshold and 1.9 percent at the lowest threshold evaluated (i.e., 25 percent above the Reference Level).

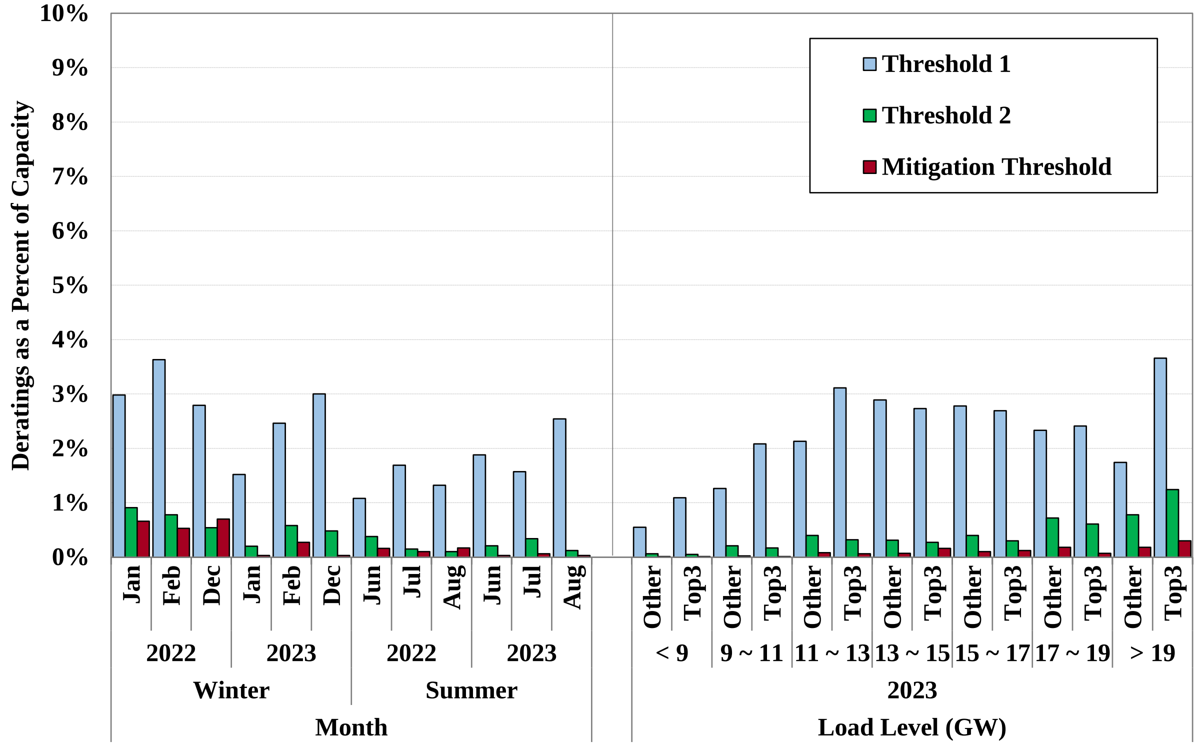
The output gap in Eastern New York is usually largest during high load conditions in summer or in peak winter conditions when fuel prices become volatile. In 2023, the summer and winter were relatively mild with low natural gas prices, which was in contrast to the year prior. Consequently, output gap at the mitigation threshold-level fell, though output gap at the lowest threshold (i.e., reference level plus 25-percent) increased. This was primarily because, as fuel prices drop and reference levels along with them, the magnitude of the lowest threshold shrinks leading it to identify more capacity in the output gap calculation.[201]

199 Analysis of the affected capacity is provided in Section VI.C.

200 Analysis of the affected capacity during the summer is provided in Section VIII.D.

201 For example, Threshold 1 would be $25/MWh based on a $20/MWh reference level, but $50/MWh on a $40/MWh reference level. Thus, this threshold binds at just $5/MWh above the reference level in the former case as opposed to $10/MWh above reference level in the latter situation.

Figure 48: Output Gap in Eastern New York
2022 – 2023



Much of the output gap in 2023 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.[202] 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 concerns 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 market power). Likewise, when an individual supplier's units must be committed to maintain

202 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.

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.[203]

- 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 49 summarizes the market power mitigation (i.e., offer capping) that was imposed in the day-ahead and real-time markets in 2022 and in 2023. The figure shows that most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for over 99 percent of all mitigation in 2023, 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 2022 to 2023 due to lower loads and the elimination of NOx bubble-related commitments.[204] 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 less than 1 percent of total mitigation and was down from 2022 levels in all areas of New York City. AMP mitigation only applies when there is an active transmission constraint. The relatively low levels of congestion in New York City load pockets during 2023 along with high load pocket thresholds relative to prices resulted in fewer instances when AMP could be applied.[205]

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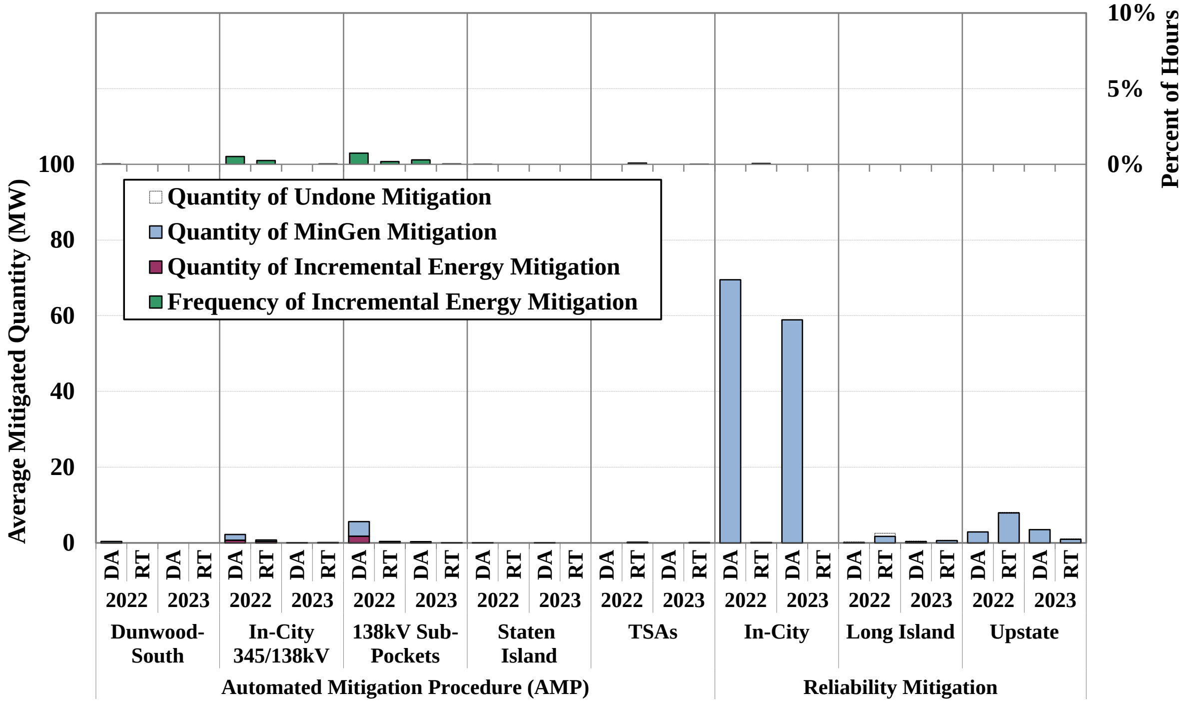
203 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

204 See Section VI.E for more details on the reduced reliability commitments in New York City.

205 NYISO AMP software did not function properly for a period from late-April to mid-July. Consequently, NYISO failed to impose mitigation on small amounts of capacity. The amount was small because generators subject to AMP rarely offer above the conduct thresholds and congestion was infrequent in NYC. See https://www.nyiso.com/documents/20142/40834869/Potential%20Market%20Problem%20Update_10.26.2023.pdf/014834e0-cd67-c46a-cf93-adeae29fb917.

Figure 49: Summary of Day-Ahead and Real-Time Mitigation
2022 - 2023



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 when the generator would be uneconomic.

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. The NYISO has considered tariff changes to Attachment H to address the potential for firms to withhold by submitting biased fuel cost adjustments.[206] Such changes would address this potential problem by imposing financial sanctions on generators that submit biased FCAs to withhold capacity.

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

206 See presentation from March 7, 2023 MIWG.

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.[207]

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.[208]

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 2021, which concluded in January 2023, included intermittent renewables, energy storage, and an HVDC transmission project with an award under the state's 'Tier 4' clean energy procurement in the mitigated capacity zones. All of the CY21 projects in the mitigated zones were considered to be Excluded Facilities and therefore not subject to BSM evaluation.

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207 See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

208 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 is beneficial for many reasons. 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. As more intermittent generation enters the market over the coming decades, demand response and price-responsive loads will become increasingly important as the NYISO maintains security and reliability at the lowest cost.

Demand response programs provide incentives for retail loads to participate in the wholesale market. The Demand-Side Ancillary Services Program (DSASP) enables economic demand response resources to participate in the ancillary services markets. The Special Case Resource (SCR) program and the Targeted Demand Response Program (TDRP) enable reliability demand response resources to be called when the NYISO or the local Transmission Owner forecasts a shortage. Currently, nearly all of the 1,295 MW of demand response resources registered in New York are reliability demand response resources.[209]

The NYISO has undertaken a series of market design initiatives to encourage greater consumer engagement. In this regard, the Distributed Energy Resource (DER) Participation Model has been designed to enable individual large consumers and consumer aggregations to play a more active role in the day-ahead and real-time markets. The DER participation model will accommodate duration limitations in their offers, payments, and obligations. Pending approval by FERC, this is slated for implementation as early as the second quarter of 2024.

This section evaluates existing demand response programs. Future reports will examine the performance of the programs that are currently under development.

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,295 MW of resources participating in 2023. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. However, the registered quantity of reliability program resources fell by more than 50 percent from 2010 to 2023 primarily because of enhancements to auditing and baseline methodologies for SCRs since

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

2011.[210] These have improved the accuracy of baselines for some resources, reducing the amount of capacity that is qualified to sell.

In the six months of the Summer 2023 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.2 percent of the UCAP requirement for New York City;
- An average of 3.6 percent of the UCAP requirement for the G-J Locality;
- An average of 0.6 percent of the UCAP requirement for Long Island; and
- An average of 3.2 percent of the UCAP requirement for NYCA.

In 2023, all SCRs were required to have a 4-hour duration and their UCAP MWs reflected the Duration Adjustment Factor of 90 percent for 4-hour resources. Beginning in the 2024/25 Capability Year, the Capacity Accreditation Factor will be determined just before the start of the capability period based on a resource adequacy modeling assessment of the reliability value of each resource type.[211]

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. These resources collectively can provide up to 415 MW of operating reserves. However, the NYISO will retire this program when DSASP resources become eligible to utilize the DER and Aggregation market rules.

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. NYISO has special scarcity pricing rules for periods when demand response resources are deployed.

In 2023, the NYISO activated the 67 MW of TDRP resources on one day in August, at the request of the Transmission Owner for sub-load pocket J3 in New York City (which is “Vernon-Greenwood”). However, response is voluntary, and the NYISO observed only 15 MW (or 23 percent) curtailment.

Additionally, demand response resources in local utility programs were activated multiple times throughout the summer of 2023. The amount of these deployments exceeded 200 MW on eight

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210 See Figure A-136 in the Section VIII.A]of the Appendix for more details.

211 See Section 4.1.1 of ICAP Manual for more details.

days, most of which was activated for peak-shaving in local TOs' servicing areas. Our analysis shows that these deployments helped avoid or reduce NYCA capacity deficiency on five of those days.[212] Prices in the wholesale energy market did not indicate a need for peak load reduction on the remaining days.[213]

Utility demand response deployments are not currently considered in the market scheduling and pricing. The capacity of utility-activated demand response is not considered in day-ahead forecasts, which may lead to excessive reliability commitments or unnecessary out-of-market actions on high-load days, although this did not occur in 2023. In addition, the deployed MW is not considered in the current scarcity pricing rules in the real-time market even though it may help avoid capacity deficiency. Peak-shaving also results in lower capacity requirements in future periods. It would be beneficial for the NYISO to work with TOs to evaluate the feasibility and appropriateness of including utility demand response deployments in its market scheduling and pricing processes.

212 See our analysis in Section V.K in the Appendix for more details.

213 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.

XII. RECOMMENDATIONS

Our analysis in this report indicates that the NYISO electricity markets performed well in 2023, although we recommend additional enhancements to improve market performance. Twenty-five recommendations are presented in four 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 2022 SOM Report, but Recommendations 2023-1 to 2023-5 are new in this report. The following tables summarize our current recommendations and any NYISO market design project work to help address the recommendation that is in the 2024 project plan and/or in the projected work for 2025 based on the September 2023 version of the Market Vision document.

High Priority Recommendations

Number	Section	Recommendation	NYISO Project Scope: (2024 / 2025)
Energy Market Enhancements – Pricing and Performance Incentives			
2017-1	VI.E	Model local reserve requirements in New York City load pockets.	N/A[214]
2015-16	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:* (Market Design Complete & Prototyping & FRS / Software Deployment)
2016-1	Appx. V.D	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2017-2	VI.A.1	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	N/A
Capacity Market – Design Enhancements			
2022-4	VIII.C	Implement more granular capacity zones and a dynamic process for updating the zones.	*Granular Capacity Market Pricing:* (Issue Discovery / Continuing)
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)

214 The 2023 Market Vision includes a 2027-2028+ project called *More Granular Operating Reserves* to address Recommendation 2017-1 following the deployment of the *Dynamic Reserves* project in 2026.

Other Recommendations

Number	Section	Recommendation	NYISO Project Scope: (2024 / 2025)
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.	N/A
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:* (Market Design Complete / Phase 1: Deployment & Phase 2: FRS)
2021-2	VI.E, VI.F	Model full reserve requirements for Long Island.	N/A
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.	*Long Island Reserve Constraint Pricing:* (Concept Proposed / Deployment)
2015-9	IX.B.1	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 appropriately reflects its operational characteristics.	*Improving Duct-Firing Modeling:* (FRS / Deployment)
2020-2	VI.A.2	Eliminate offline fast-start pricing from the real-time dispatch model.	*Eliminate Offline GT Pricing:* (/ Deployment)
2012-8	Appx. V.F	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
2012-13	Appx. IV.D	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	N/A

Number	Section	Recommendation	NYISO Project Scope: (2024 / 2025)
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.4	Update market processes to mitigate the risk of extreme pricing caused by inaccuracies in the Winter-Summer Ratio parameter.	N/A
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:* (Issue Discovery / Market Design Complete)
2022-2	VIII.G	Establish seasonal capacity requirements and demand curves.	*Winter Reliability Capacity Enhancements:* (Issue Discovery / Market Design Complete)
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
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 the 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 the 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

2023-1: Allocate congestion residuals to NYTOs based on incremental transfer capability scheduled in the DAM.

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.[215] 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 the 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.

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215 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.[216] 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 the 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. [217]

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.

216 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;"

217 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 2023 *Balancing Intermittency* project to develop a market design concept proposal, NYISO defined Phase 1, which will use existing reserve products to satisfy new Uncertainty Reserve Requirements for net load and renewable generation forecast error, and Phase 2, which will define new 1-hour and 4-hour products for longer time frames. Phase 1 is planned for deployment in 2025, and Phase 2 is planned for deployment in 2026.[218]

2021-2: Model full reserve requirements for Long Island.

The current Long Island reserve requirement is usually adequate to maintain security and reliability following the largest contingency, but it is necessary to hold reserves on Long Island to satisfy N-1-1-0 criteria (i.e., normal line loading following the two largest contingencies). Because this requirement is not included in the market software, system operators have relied on out-of-market commitments during some conditions (e.g., the summer of 2021).[219] Moreover, increasing penetration of intermittent renewable generation will increase the need for out-of-market commitments. Modeling the full reserve requirements for Long Island 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-merit actions. This will likely require sufficient reserves to satisfy N-1-1-0 criteria.

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-

218 See *Balancing Intermittency: Percentiles and Shortage Pricing Curves*, presented to the Market Issues Working Group on March 4, 2024.

219 See discussion in Section VII.B. Also see our *2021-Q3 Quarterly Report on the NYISO Markets* (pages 11 and 76), available here.

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 2026 along with the deployment of *Dynamic Reserves*, which will include the capability to dynamically procure reserves on Long Island.[220]

2017-1: Model local reserve requirements in New York City load pockets. (Current Effort, High Priority)

The NYISO is required to maintain sufficient energy and operating reserves to satisfy N-1-1-0 local reliability criteria in New York City. These local requirements are not satisfied through market-based scheduling and pricing, so it is necessary for the NYISO to satisfy these 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. Hence, we recommend the NYISO implement local reserve requirements in the New York City load pockets.

We designate this recommendation as High Priority partly because of significant transmission and resource mix changes planned for New York City over the next five to ten years. New transmission and the retirement of peaking generation will shift the location of reserve-

220 See *Long Island Reserve Constraint Pricing*, presented to the Market Issues Working Group on February 7, 2024.

constrained areas from relatively localized load pockets to larger load pockets within New York City. Further, the interconnection of offshore wind generation in New York City will lead to larger and more variable operating reserve requirements. Localized operating requirements will help the 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 2027 when it tentatively plans a market design complete for the "More Granular Operating Reserves" project.[221] We also encourage NYISO to consider whether local reserve requirements should consider the loss of multiple generators due to a natural gas system contingency.

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;

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[221] The 2023 Market Vision includes a 2027-2028+ project called *More Granular Operating Reserves* to address Recommendation 2017-1 following the deployment of the *Dynamic Reserves* project in 2026.

- 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.

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 2026.[222]

[222] See *Dynamic Reserves*, presented to the Market Issues Working Group on January 25, 2024.

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 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. The NYISO should consider these tradeoffs in its evaluation of Dynamic Reserves.

This recommendation is a high priority because it will enable the 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: In 2023, NYISO developed a market design concept that would address this recommendation, although we have raised concerns with elements of the proposal which are being considered in 2024.[223] NYISO currently targets deployment in 2026.

Energy Market Enhancements – Real-Time Market Operations

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, the 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

[223] See *Dynamic Reserve Market Design*, presented to the Business Issues Committee on December 13, 2023.

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 develop the Functional Requirements in 2024 and deploy the design in 2025.[224]

2020-2: Eliminate offline fast-start pricing from the real-time dispatch model. (Current Effort)

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.

Status: NYISO's 2023 Market Vision includes a project to address this recommendation for deployment in 2025.

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

224 See NYISO MIWG/ICAPWG presentation on September 30, 2022 *Improve Duct-Firing Modeling – Update*. NYISO's preliminary design would work by allowing generators to designate some operating ranges as available for energy at a reduced response rate but unable to provide regulation and 10-minute reserves. This design is promising, but generators would identify the duct-firing range using a registration parameter rather than a biddable parameter. Since the duct-firing range moves like the upper operating limit based on ambient temperature and humidity conditions, it is unclear whether the design will provide significant benefits until the duct-firing range is a biddable parameter.

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).[225]

We recommend that the 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.

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.

Differences in the ramp assumptions for units that are in the process of shutting-down and changes in external transactions schedules between RTC and RTD are a principal driver the price volatility evaluated above. To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:

a) Add two near-term look-ahead evaluation periods to RTC and RTD around the quarter-hour to allow it them to accurately anticipate the ramp needs for a de-commitment or interchange adjustment. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.
b) Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
c) Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
d) Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbine generators with the actual demonstrated performance to account for units that often ramp at a rate that is lower than their claimed ramp rate capability.
e) Address inconsistencies between the ramp assumptions used in RTD's physical pass and RTD's pricing pass when units are ramping down from a day-ahead schedule.
f) Modify ramp limits of individual units to reflect that a unit providing regulation service cannot ramp as far in a five-minute interval as a unit not providing regulation (since deployments may lead the unit to move against its five-minute dispatch instruction).

This recommendation is likely to become more important in the future because the CTS process has potential to provide significant additional flexibility above the current limit of 300 MW of adjustment every 15 minutes. Additional flexibility will be important as NYISO integrates more intermittent renewable generation in the coming years.

225 See Section V.F in the Appendix.

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 the 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.

The 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 the NYISO currently does not expect to implement this before 2028.[226] 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. Therefore, we recommend the 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.

2022-1: Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs. (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

[226] The 2023 Market Vision plans for deployment of *Winter Reliability Capacity Enhancements* in 2028.

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.[227] 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 NYISO's 2024 *Valuing Transmission Security* project will assess the different contributions of individual resources to transmission security and resource adequacy. It will evaluate "if and how transmission security should be valued in the capacity market" and the "effectiveness of ICAP market price signals when transmission security limitations are reflected in the capacity market."[228]

2022-2: Establish seasonal capacity requirements and demand curves. (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 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

227 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.

228 See *Valuing Transmission Security: Key Concepts Overview*, presented March 4, 2024 to the ICAP Working Group.

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 NYISO's 2024 *Winter Reliability Capacity Enhancements: Project Kick Off* project will produce a report "to detail the potential impacts to the ICAP market from a shift to a winter peaking/winter risk system and identify issues related to market design, and identify potential future work."

2022-4: Implement more granular capacity zones and a dynamic process for updating the zones. (High Priority, Current Effort)

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 NYISO's 2024 *Granular Capacity Zones* project will produce a report to "Understand the considerations and potential impacts of creating a new process for evaluating what capacity zones are needed and explore the frequency that zones should be re-examined. Additionally, this project will evaluate what demand curves may be needed for export constrained regions." [229]

2021-4: Improve capacity modeling and accreditation for specific types of resources.

The 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 NYISO's resource adequacy model GE MARS. These changes establish a framework for efficiently compensating resources in the capacity market. However, limitations in current MARS modeling techniques may prevent some resource types from being evaluated as accurately as possible:

a) Winter fuel limitations – MARS does not model limits on the output of gas-fired units without backup fuel that are jointly unavailable during extreme cold weather;
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

[229] See *Granular Capacity Zones*, presented March 4, 2024 to the ICAP Working Group.

e) Conventional Generators Receiving Excessive Credit – Several categories of generation receive excessive credit under current rules, including (i) generators with ambient water temperature and humidity restrictions 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 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, (d) inflexible generators, and (e) conventional generators receiving excessive capacity credit.[230] For generators with limited backup fuel, it will become 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: The NYISO and NYSRC have already made significant progress towards addressing this recommendation in the following ways:

a) Winter fuel limitations – Starting with the 2025/26 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, the NYISO and NYSRC are actively working this year to assess potential improvements to energy storage modeling, winter load shapes, and correlations among weather-dependent resources and loads.[231] 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

230 See discussion in Section VIII.D. Also see discussion of functionally unavailable capacity on high load days in our 2023-Q3 Quarterly Report on the NYISO markets (pages 19-20).

231 See *NYISO Resource Adequacy Model Strategic Plan (2024-2028)*, presented to the September 8, 2023 NYSRC Executive Committee.

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.

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.

Enhance Planning Processes

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 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

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 the 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.

Market Developments Since the 2022 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendation from the 2022 State of the Market Report:

2015-17: Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages. – Historically, transmission constraints that could not be resolved were “relaxed” (i.e., the limit was raised to a level that would accommodate the flow). This did not lead to efficient real-time prices that reflect the reliability consequences of violating the constraint. To address this, the NYISO began to use a Graduated Transmission Demand Curve (GTDC) to set prices during the vast majority of transmission shortages starting in June 2017.

The use of the GTDC was a significant improvement, but it did not appropriately prioritize transmission constraints according to the importance of the facility, the severity of the violation, or other relevant criteria. Hence, we recommended the NYISO replace the single GTDC with multiple GTDCs that can vary according to the importance, severity, and/or duration of the transmission constraint violation. In November 2023, the NYISO partially addressed this recommendation by aligning GTDCs with the actual constraint reliability margin (CRM) of specific transmission facilities. We anticipate the new GTDCs will improve pricing efficiency during tight conditions.

Analytic Appendix

2023 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. The NYISO also 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 2023 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.

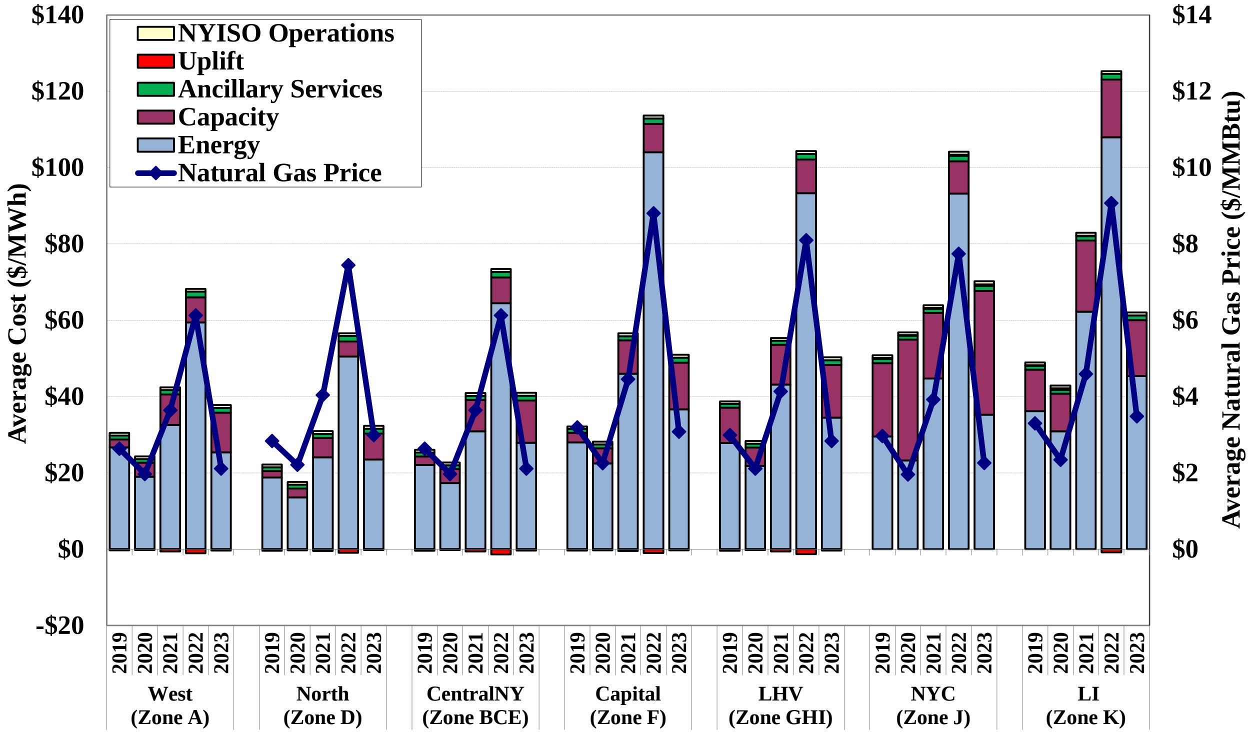
A. Wholesale Market Prices

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 is 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 since both capacity and energy prices vary substantially by location.

The energy prices in this metric are load-weighted average real-time energy prices. The capacity component is calculated based on clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over the energy consumption in that area. The uplift component is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area. For the purposes of this metric, costs associated with ancillary services are distributed evenly across all locations. Figure A-1 shows the average all-in prices along with the average natural gas prices from 2019 to 2023 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
2019 – 2023



Natural gas prices are based on the following gas indices (plus a transportation charge): (a) the Niagara index during the months December through 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.[232] 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 on top of the delivered gas prices.

Figure A-2: Day-Ahead Electricity and Natural Gas Costs

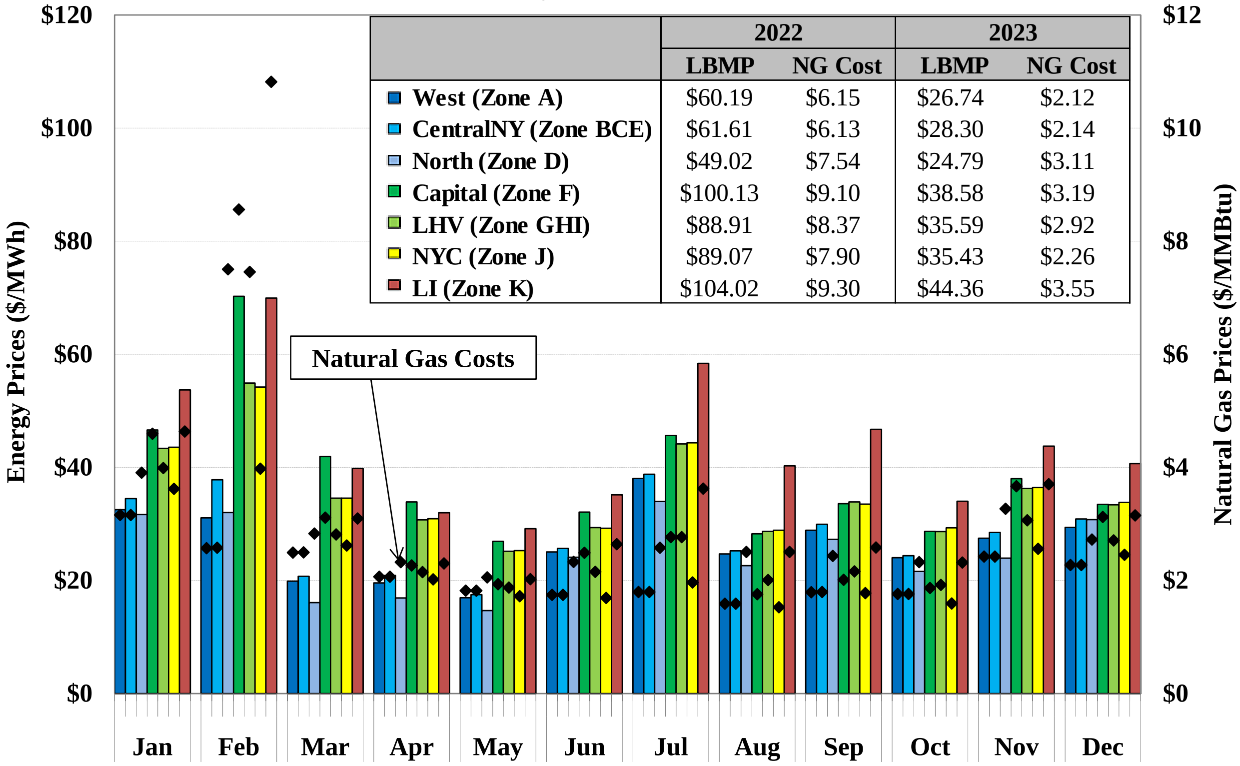
Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2023 for the seven locations shown in Figure A-2. The table overlapping the chart shows the annual averages of natural gas costs and LBMPs for 2022 and 2023. Although hydro and nuclear generators produce much of the electricity used by New York

232 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.

consumers, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York.[233]

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs

By Month, 2023



	2022		2023	
	LBMP	NG Cost	LBMP	NG Cost
West (Zone A)	$60.19	$6.15	$26.74	$2.12
CentralNY (Zone BCE)	$61.61	$6.13	$28.30	$2.14
North (Zone D)	$49.02	$7.54	$24.79	$3.11
Capital (Zone F)	$100.13	$9.10	$38.58	$3.19
LHV (Zone GHI)	$88.91	$8.37	$35.59	$2.92
NYC (Zone J)	$89.07	$7.90	$35.43	$2.26
LI (Zone K)	$104.02	$9.30	$44.36	$3.55

Figure A-3: Average Monthly Implied Marginal Heat Rate

The following figure summarizes the monthly average implied marginal heat rate. The implied marginal heat rate, the calculation of which is described in detail below, highlights changes in electricity prices that are not driven by changes in fuel prices.

The *Implied Marginal Heat Rate* equals 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).[234] Thus, 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, this would imply that a generator with a 9.8 MMBtu per MWh heat rate is on the margin.[235]

233 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.

234 The generic VOM cost is assumed to be $3 per MWh in this calculation.

235 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 shows the load-weighted average implied marginal heat rate in each month of 2023 for the seven locations shown in Figure A-1 and in Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2022 and in 2023 at these seven locations. By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

Figure A-3: Average Monthly Implied Marginal Heat Rate

Day-Ahead Market, 2023

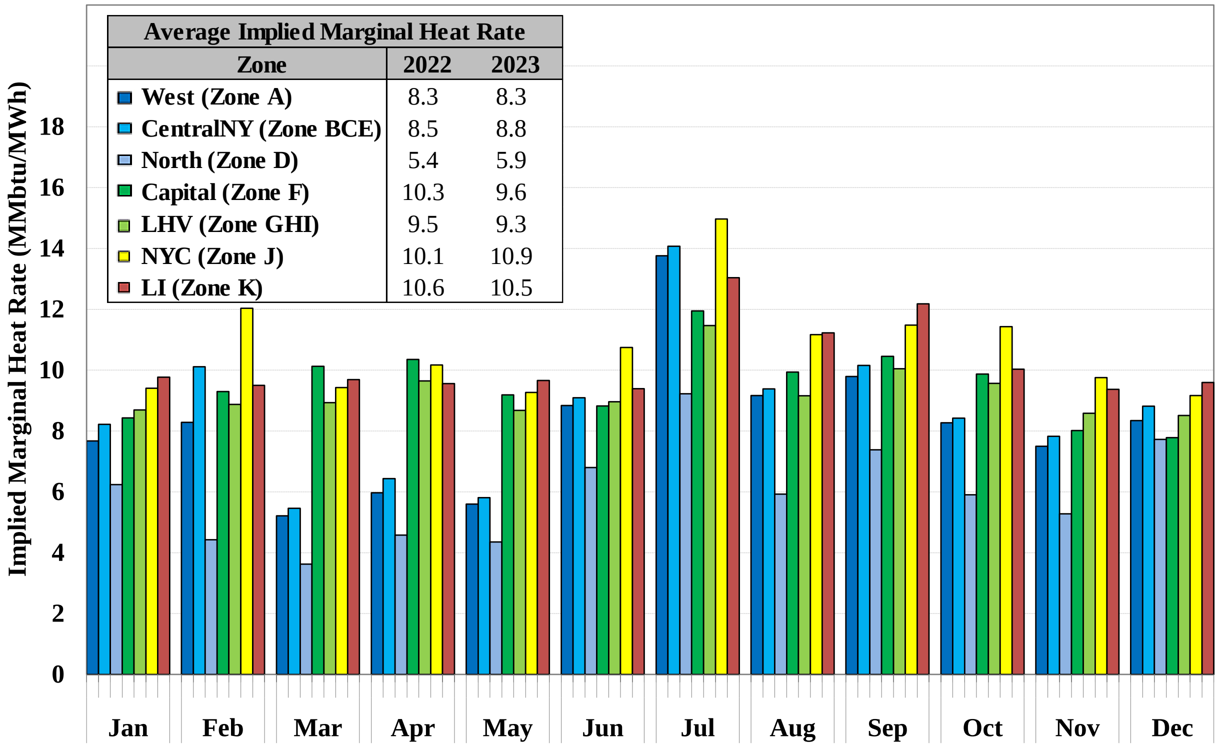


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours and at different locations. Figure A-4 shows seven price duration curves for 2023, 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 on the horizontal axis when the load-weighted average real-time price for each region was greater than the level shown on the vertical axis. The table in the chart shows the number of hours in 2023 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, in which 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. As such, a small number of hours with price spikes can have a significant effect on the average price level.[236]

Figure A-4: Real-Time Price Duration Curves by Region
2023

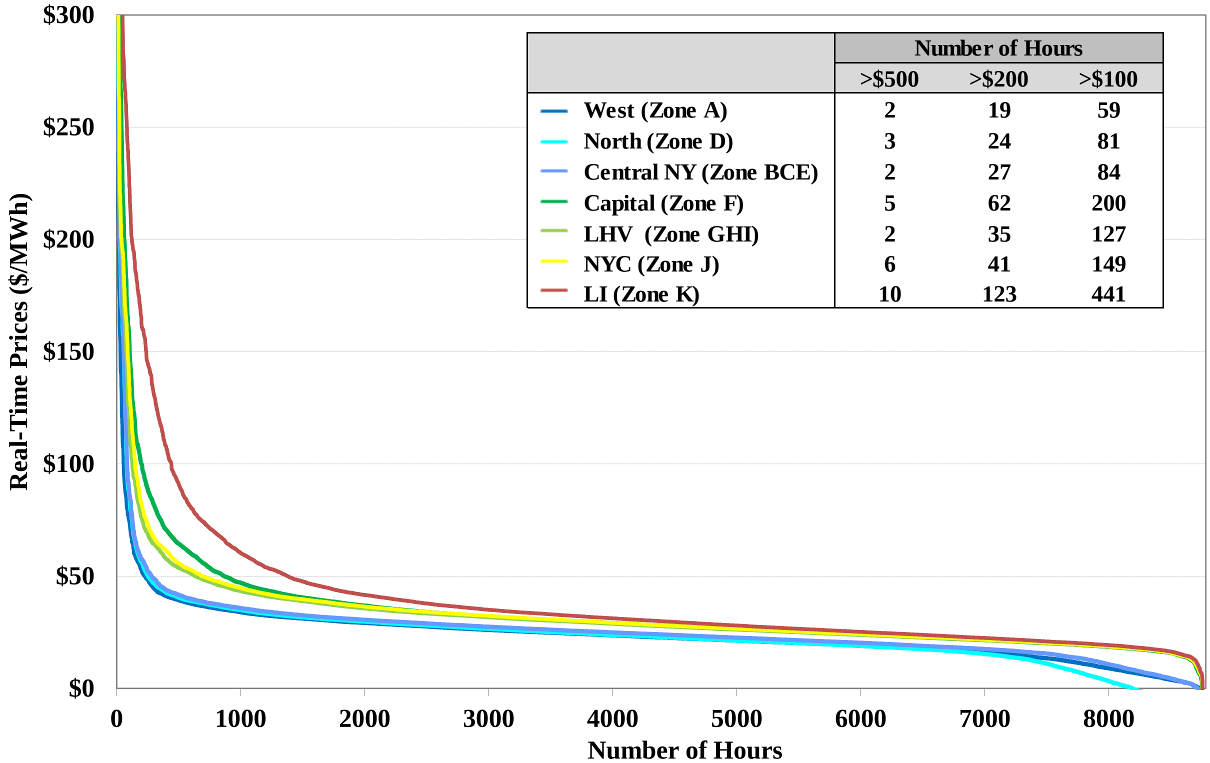
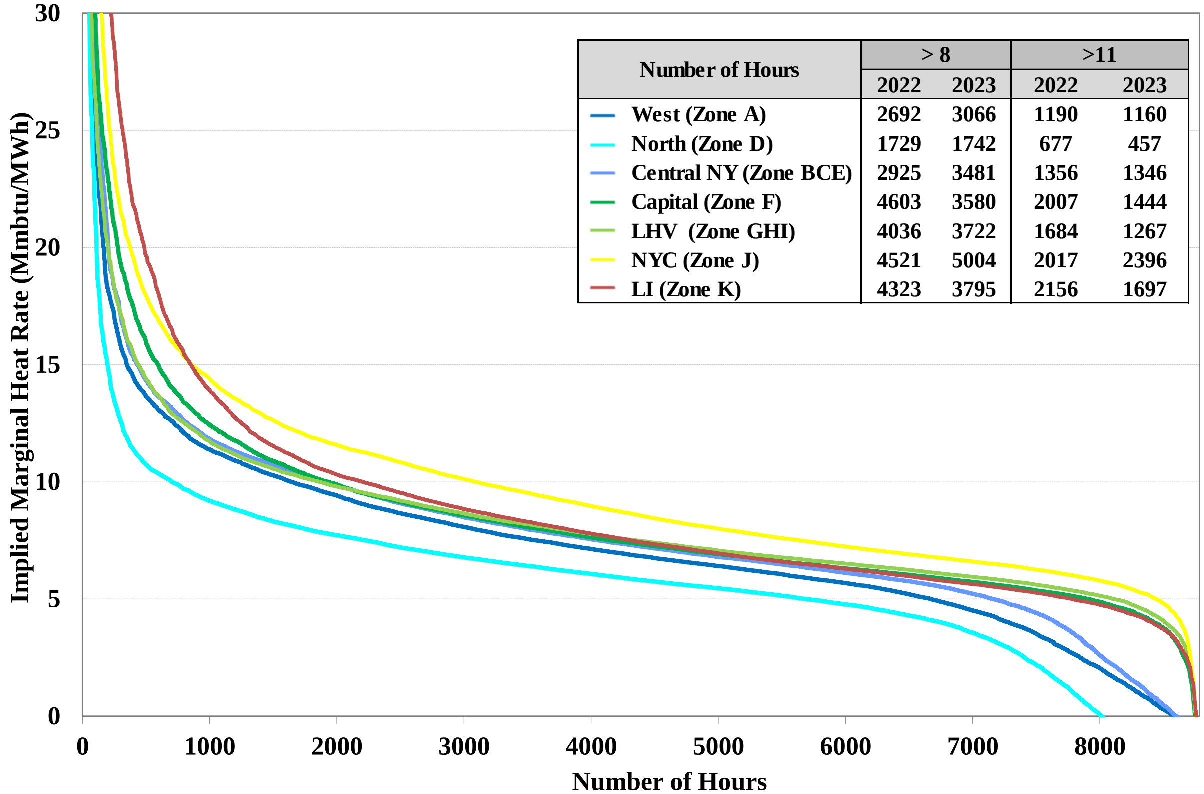


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2023. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation of the implied marginal heat rate is similar to the one in Figure A-3 except that this is based on real-time 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 2022 and 2023.

236 In other words, the distribution of energy prices across the year is "right skewed" which means that the average is greater than the median observation due to the impact of shortage pricing hours.

Figure A-5: Implied Heat Rate Duration Curves by Region
2023



Number of Hours	> 8		>11	
	2022	2023	2022	2023
West (Zone A)	2692	3066	1190	1160
North (Zone D)	1729	1742	677	457
Central NY (Zone BCE)	2925	3481	1356	1346
Capital (Zone F)	4603	3580	2007	1444
LHV (Zone GHI)	4036	3722	1684	1267
NYC (Zone J)	4521	5004	2017	2396
LI (Zone K)	4323	3795	2156	1697

B. Fuel Prices and Generation by Fuel Type

Figure A-6 to Figure A-8: Monthly Average Fuel Prices 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.[237] This is because fuel costs account for the majority 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 the majority 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.[238] Since most large steam units can burn either oil

237 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.

238 For instance, if natural gas is difficult to obtain on short notice, or if there is uncertainty about its availability. 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.

or 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.[239]

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 2020 to 2023. The table compares the annual average fuel prices for these four years. [240]

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2023 as well as for all of the NYCA.[241] The table in the chart shows annual average generation by fuel type from 2021 to 2023.

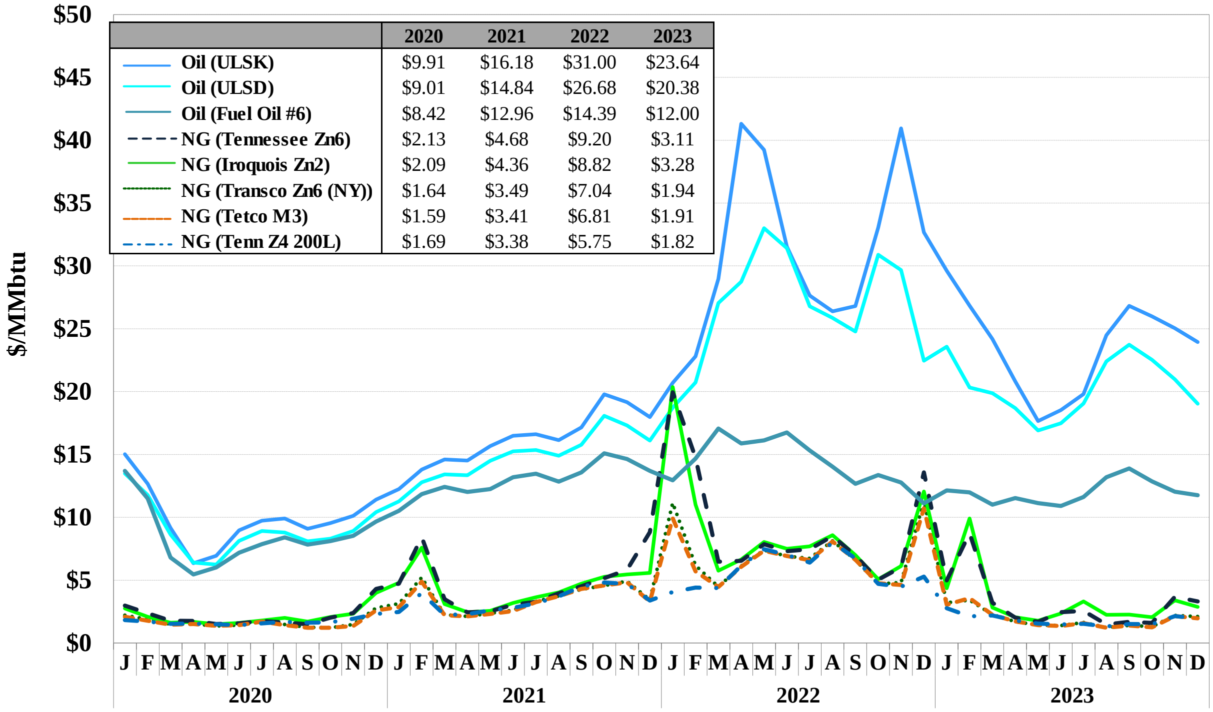
Figure A-8 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2023. The table in the chart shows annual statistics by fuel type from 2021 to 2023. More than one type of unit may be marginal in an interval, 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.

239 The conventional steam units that have dual-fuel capability burn an oil type that is either residual fuel oil (No. 6), No. 4 oil, or No. 2 oil (ULSD). .However, emissions restrictions have tightened over the past years such that some steam turbines in New York City burn a No. 4 residual fuel oil blend.

240 These are index prices that do not include transportation charges or applicable local taxes.

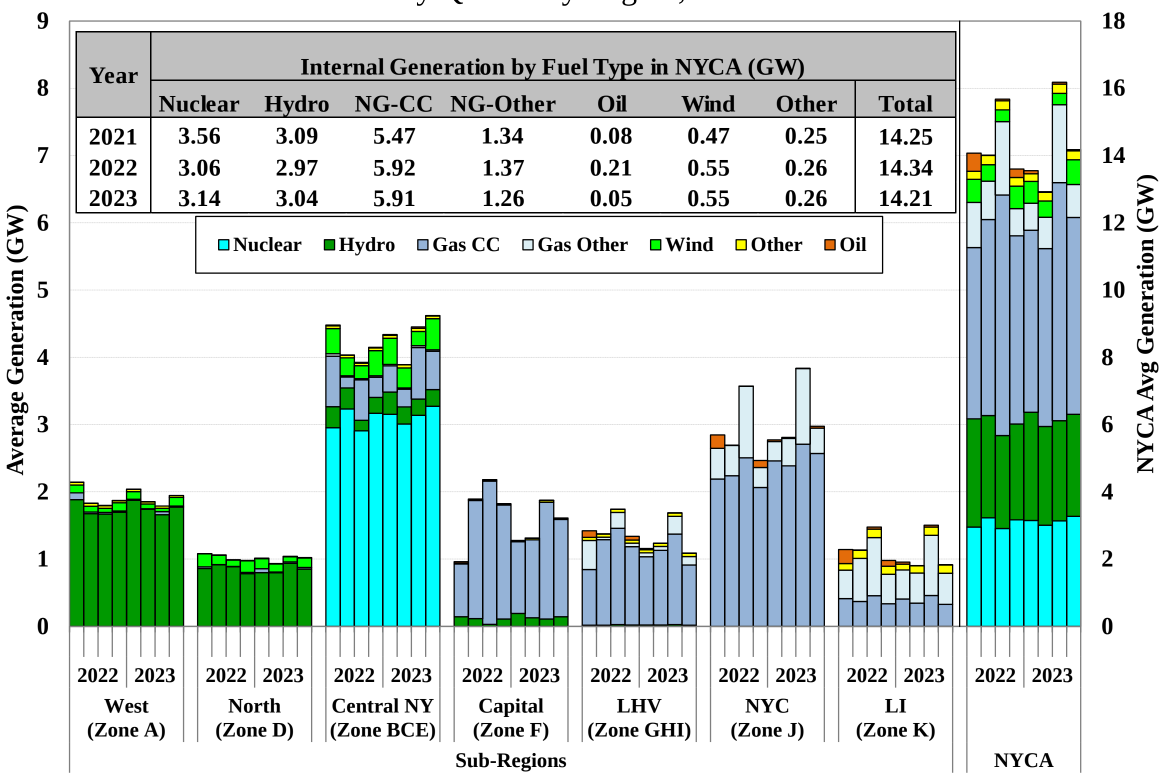
241 Pumped-storage resources in pumping mode are treated as negative generation. The “Other” category includes methane, refuse, solar, and wood.

Figure A-6: Monthly Average Fuel Index Prices
2020 – 2023



	2020	2021	2022	2023
Oil (ULSK)	$9.91	$16.18	$31.00	$23.64
Oil (ULSD)	$9.01	$14.84	$26.68	$20.38
Oil (Fuel Oil #6)	$8.42	$12.96	$14.39	$12.00
NG (Tennessee Zn6)	$2.13	$4.68	$9.20	$3.11
NG (Iroquois Zn2)	$2.09	$4.36	$8.82	$3.28
NG (Transco Zn6 (NY))	$1.64	$3.49	$7.04	$1.94
NG (Tetco M3)	$1.59	$3.41	$6.81	$1.91
NG (Tenn Z4 200L)	$1.69	$3.38	$5.75	$1.82

Figure A-7: Generation by Fuel Type in New York
By Quarter by Region, 2023

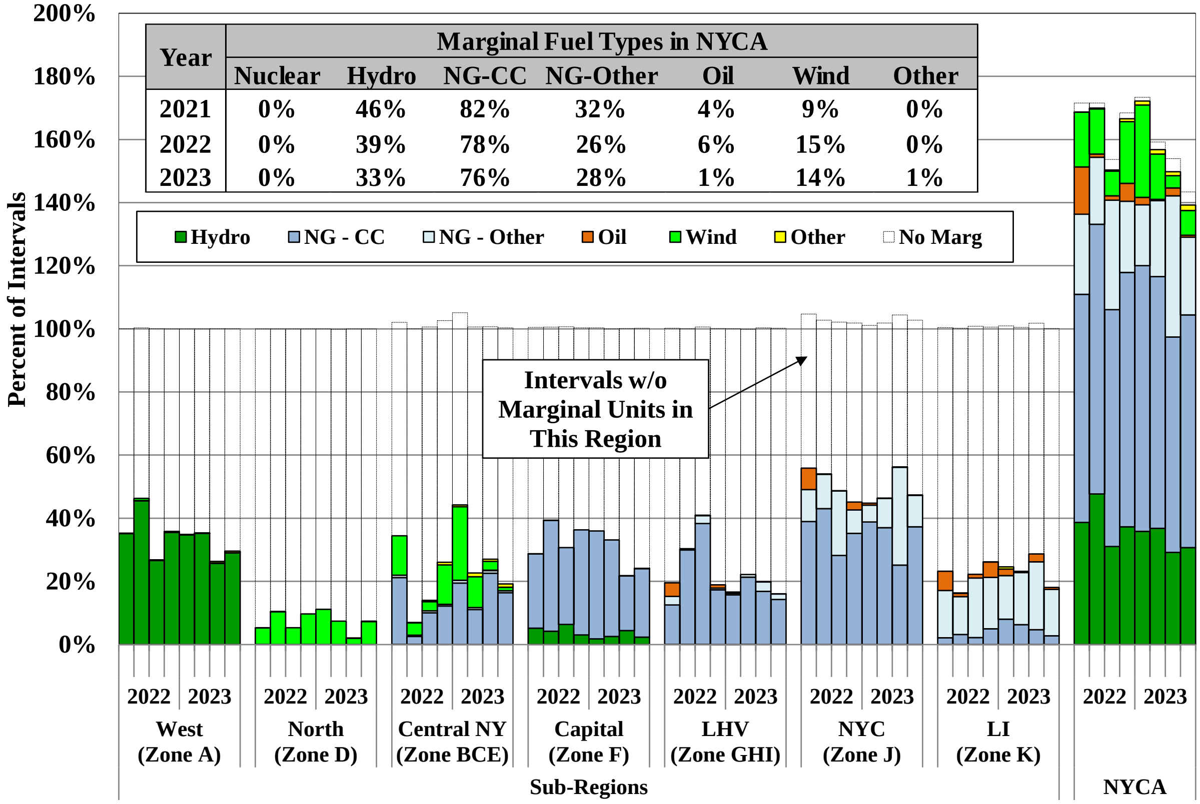


Year	Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2021	3.56	3.09	5.47	1.34	0.08	0.47	0.25	14.25
2022	3.06	2.97	5.92	1.37	0.21	0.55	0.26	14.34
2023	3.14	3.04	5.91	1.26	0.05	0.55	0.26	14.21

The fuel type for each generator in both Figure A-7 and Figure A-8 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-8: Fuel Types of Marginal Units in the Real-Time Market in New York

By Quarter by Region, 2023



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 have dual-fuel capability, allowing them to switch to an alternative fuel when natural gas becomes expensive or unavailable. However, the increase of 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.

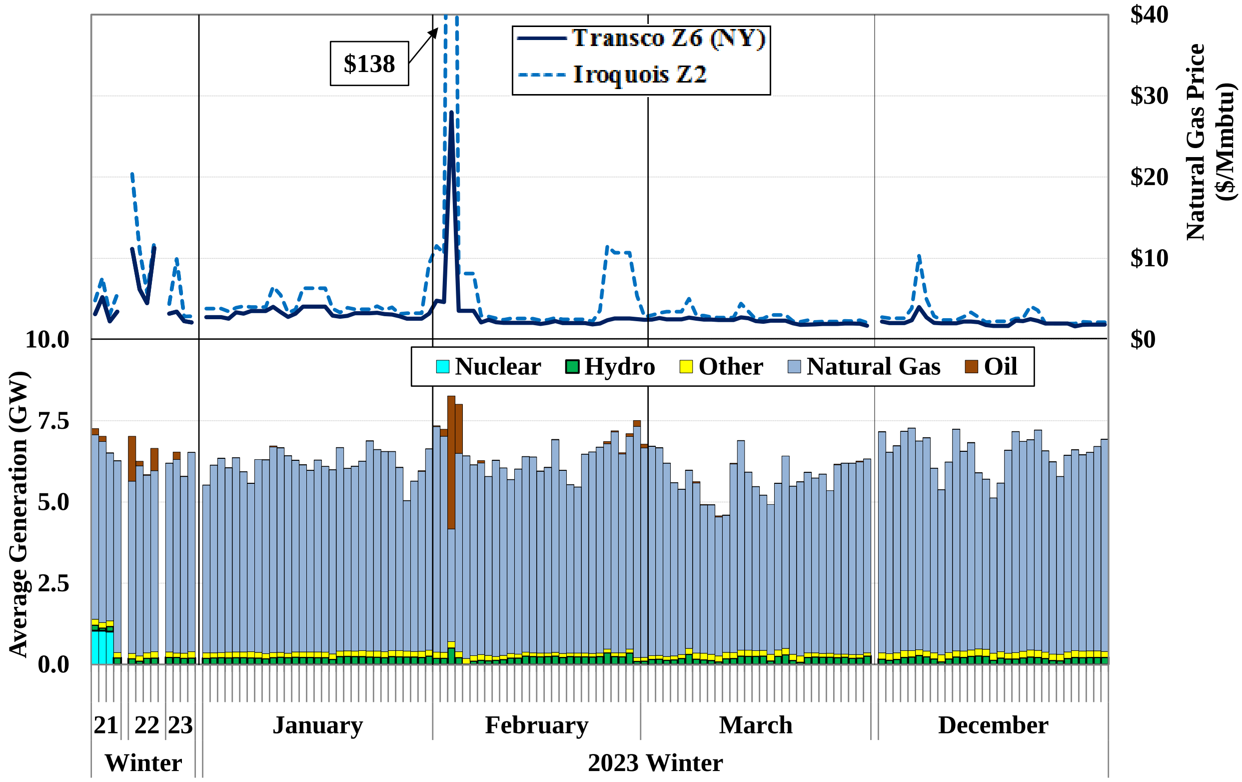
This subsection examines actual fuel usage in the winter of 2023, focusing on the portion of the year where the supply of natural gas is likely to be tight. This has historically had a big impact on the system operations, especially in Eastern New York.

Figure A-9: Actual Fuel Use and Natural Gas Prices in the Winter

Figure A-9 summarizes the average hourly generation by fuel consumed in Eastern New York on a daily basis during the winter months of 2023 (including the months of January, February, March, and December).

Figure A-9: Actual Fuel Use and Natural Gas Prices

Eastern New York, Winter Months, 2023



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 2021 and 2023. 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-10: Historical Emissions by Quarter in NYCA

Figure A-10 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-10: Historical Emissions of CO_2, NO_x, and SO_2 in NYCA

By quarter, 2000-2023

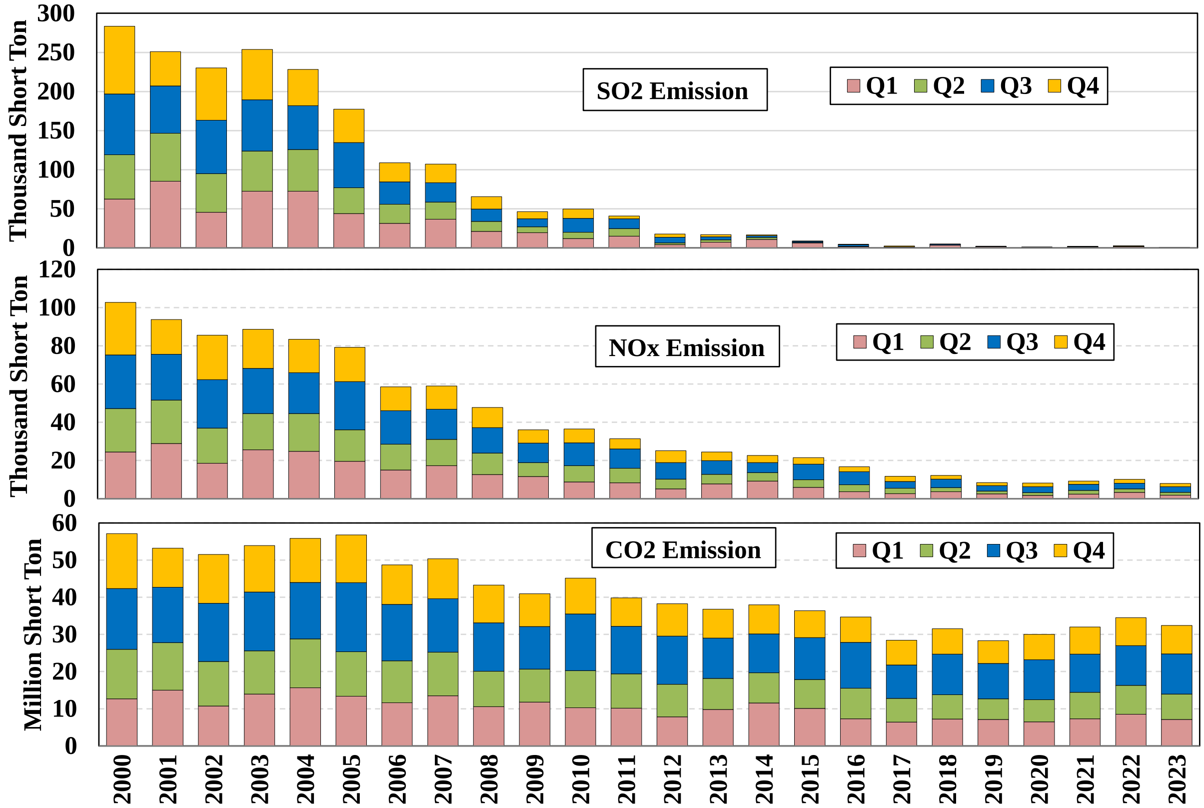


Figure A-11 - Figure A-13: Emissions by Region by Fuel Type

The following three figures show quarterly emissions across the system by generation fuel type for CO_2, NOx, and SO_2, respectively. Emission values are given for seven regions as well as the system as a whole for 2022 and 2023. 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 tables in each chart provides summary data on the total tonnage of emissions by fuel type.

Figure A-11: CO_2 Emissions by Region by Fuel Type
by quarter, 2022-2023

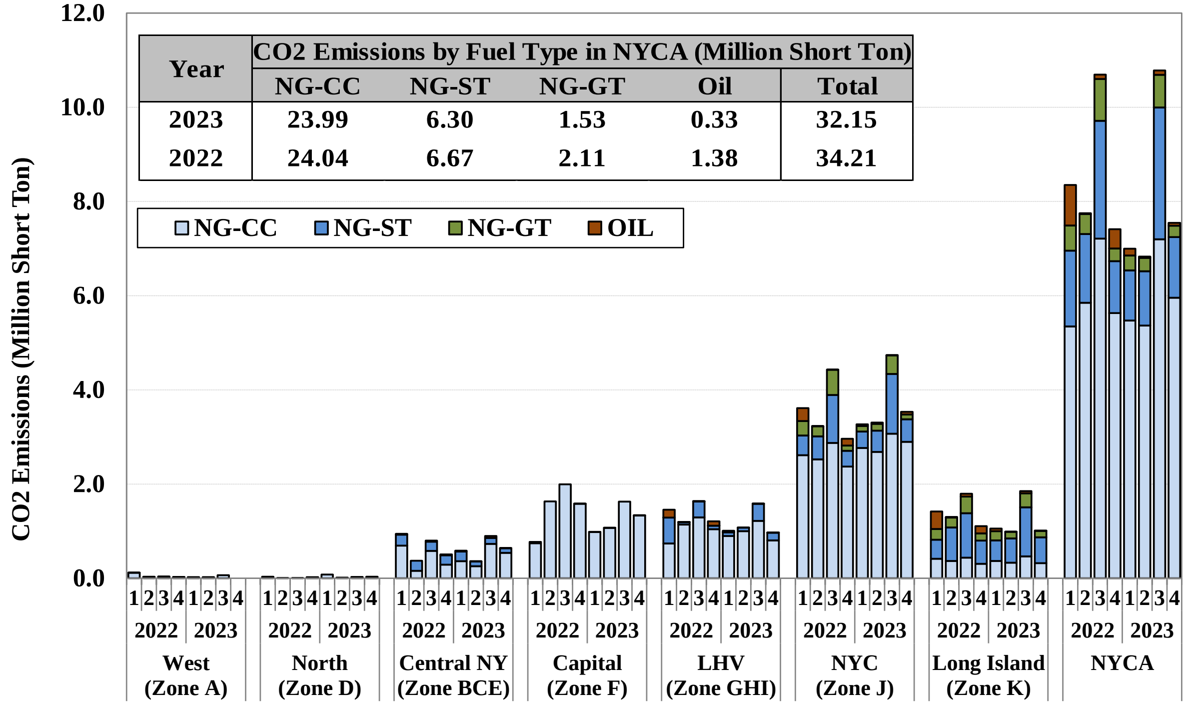


Figure A-12: NOx Emissions by Region by Fuel Type
by quarter, 2022-2023

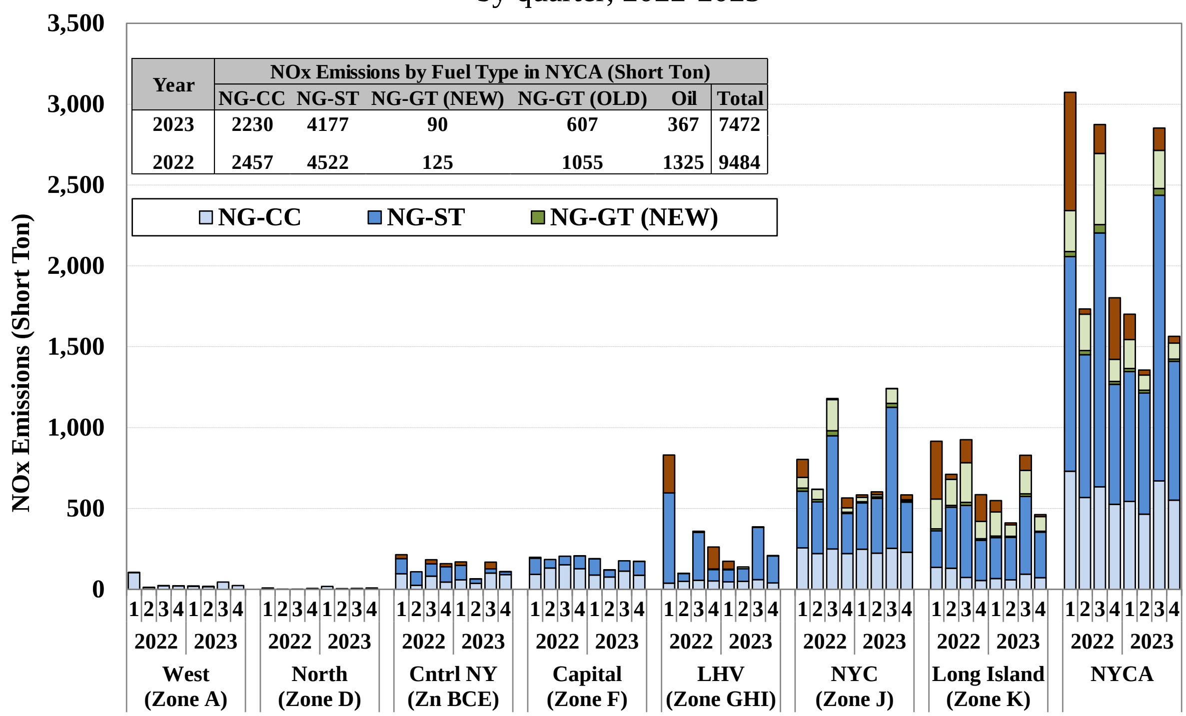
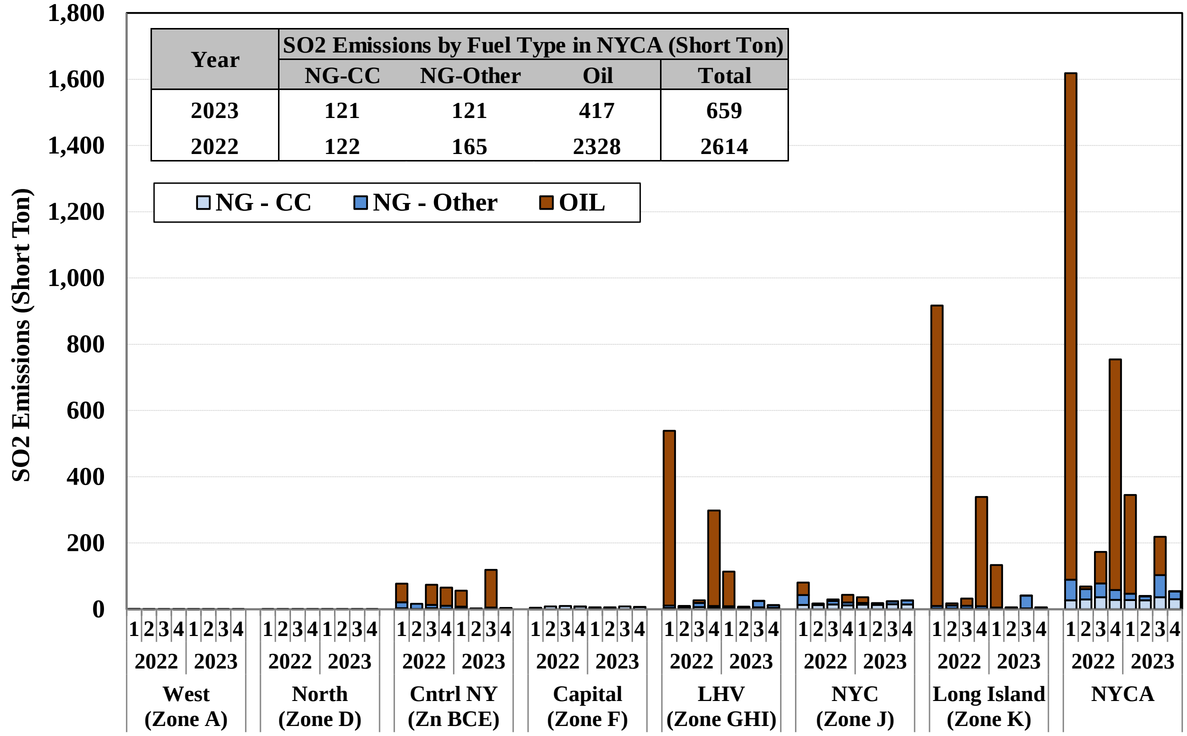


Figure A-13: SO_2 Emissions by Region by Fuel Type
by quarter, 2022-2023



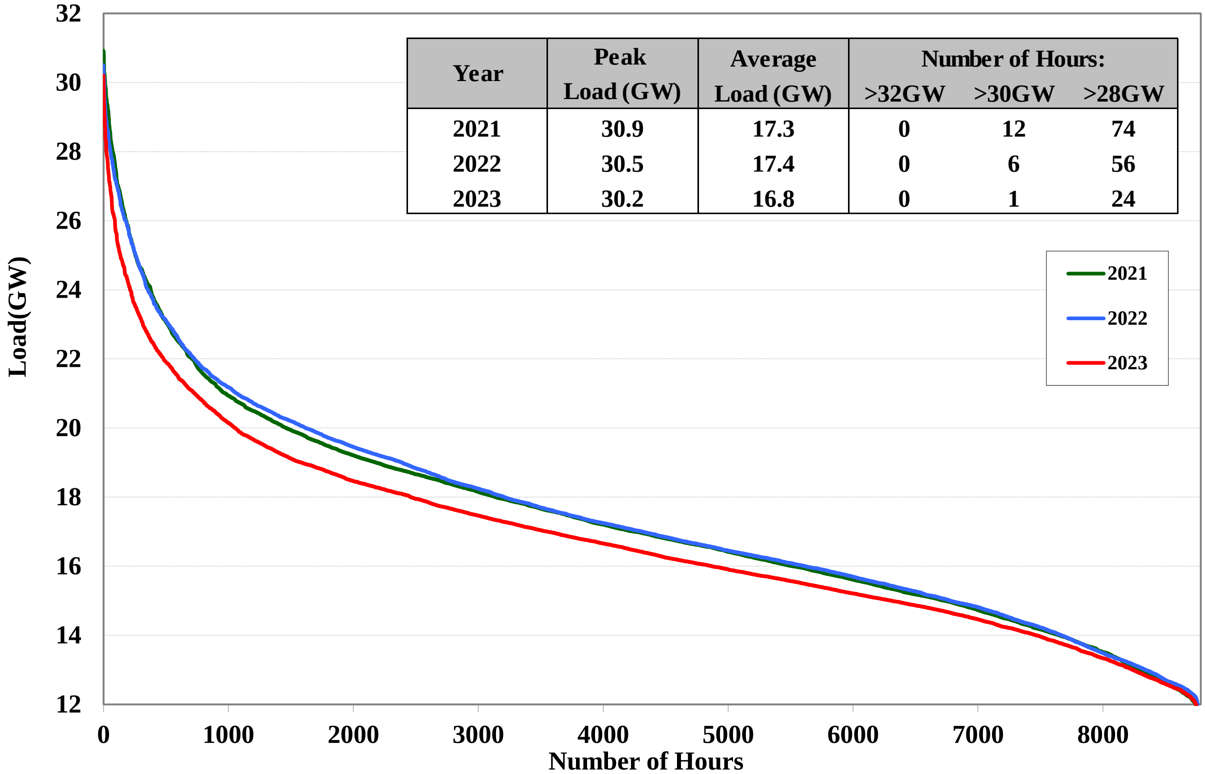
E. Load Levels

Figure A-14: Load Duration Curves for New York State

The interaction between electric supply and consumer demand also drives price movements in New York. Since changes in the quantity of supply from year-to-year are usually small, fluctuations in electricity demand explain much of the short-term variations in electricity prices. The hours with the highest loads are important because a disproportionately large share of both the market costs to consumers and the revenues to generators occur during these hours.

The load duration curves in Figure A-14 illustrate the variation in demand during each of the last three years. Load duration curves show the number of hours on the horizontal axis in which the statewide load was greater than or equal to the level shown on the vertical axis. The table in the figure shows the average load level on an annual basis for the past three years along with the number of hours in each year when the system was under high load conditions (i.e., when load exceeded 28, 30, and 32 GW).

Figure A-14: Load Duration Curves for New York State
2021 – 2023



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.

The NYISO has four 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. Figure A-15 shows the average day-ahead prices for these four ancillary services products in each month of 2022 and 2023. 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).

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 underlying 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

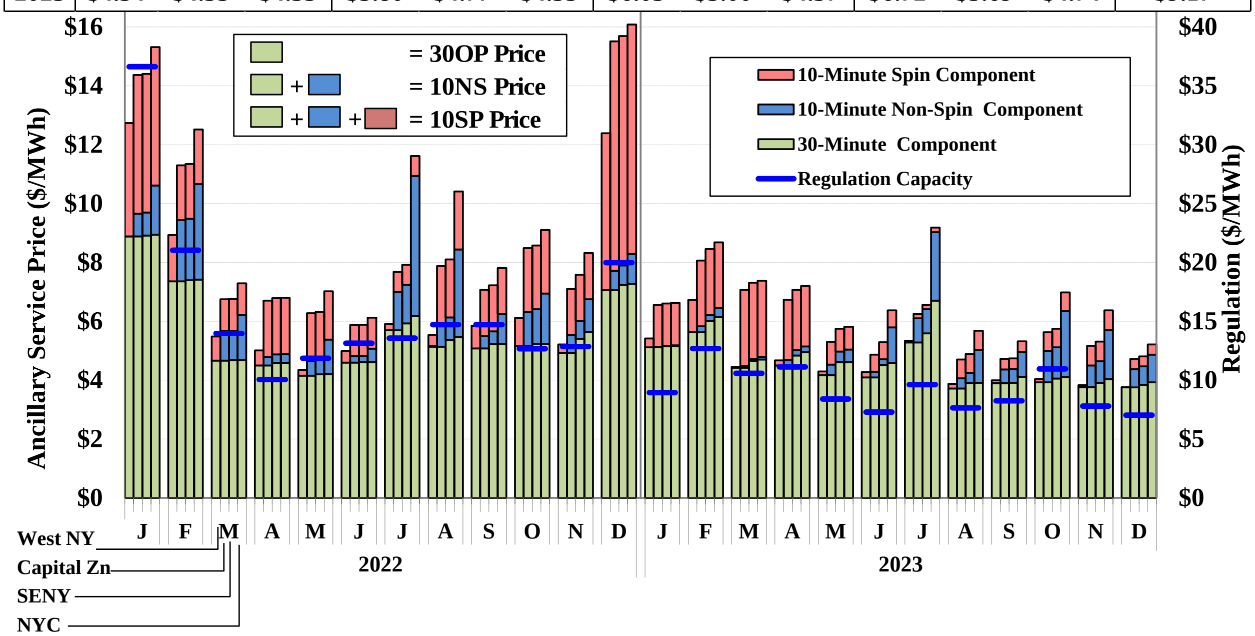
- The 10-minute spinning component represents the cost to simultaneously meet the 10-minute spinning reserve requirements for East New York and NYCA (New York City and Southeast New York do not have separate 10-minute spinning reserve requirements).

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 2022 and 2023 on an annual basis.

Figure A-15: Day-Ahead Ancillary Services Prices

2022 - 2023

Year	West NY			Capital Zone			Southeast NY			New York City			Regulation
	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
2022	$6.87	$5.59	$5.59	$8.75	$6.40	$5.59	$8.88	$6.54	$5.72	$9.87	$7.53	$5.78	$16.26
2023	$4.54	$4.35	$4.35	$5.80	$4.77	$4.35	$6.03	$5.00	$4.57	$6.72	$5.69	$4.74	$9.17



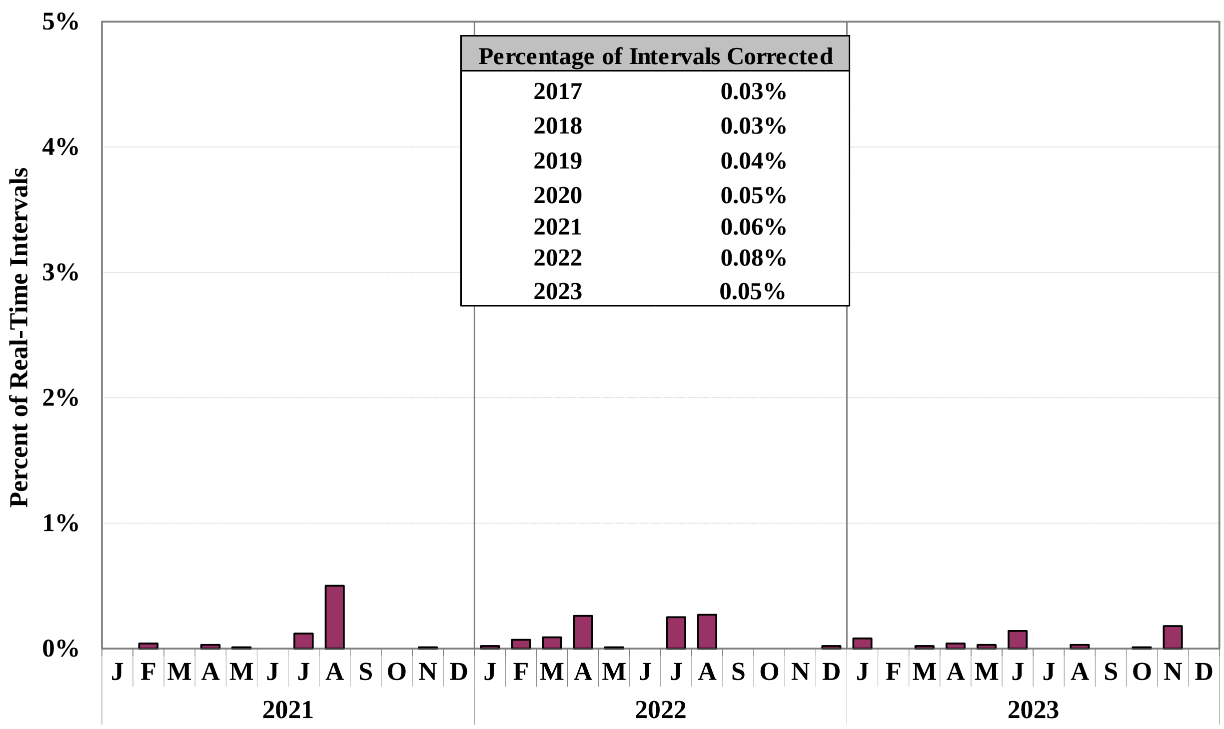
G. Price Corrections

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 summarizes the frequency of price corrections in the real-time energy market in each month from 2021 to 2023. The table in the figure indicates the change of the frequency of price corrections over the past several years. Price corrections continue to be very infrequent.

Figure A-16: Frequency of Real-Time Price Corrections
2021 - 2023



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 the efficient commitment of generating resources, procurement of fuel, and scheduling of external transactions. In addition, persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer their resources at marginal cost in the day-ahead market. We expect random variations resulting 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.

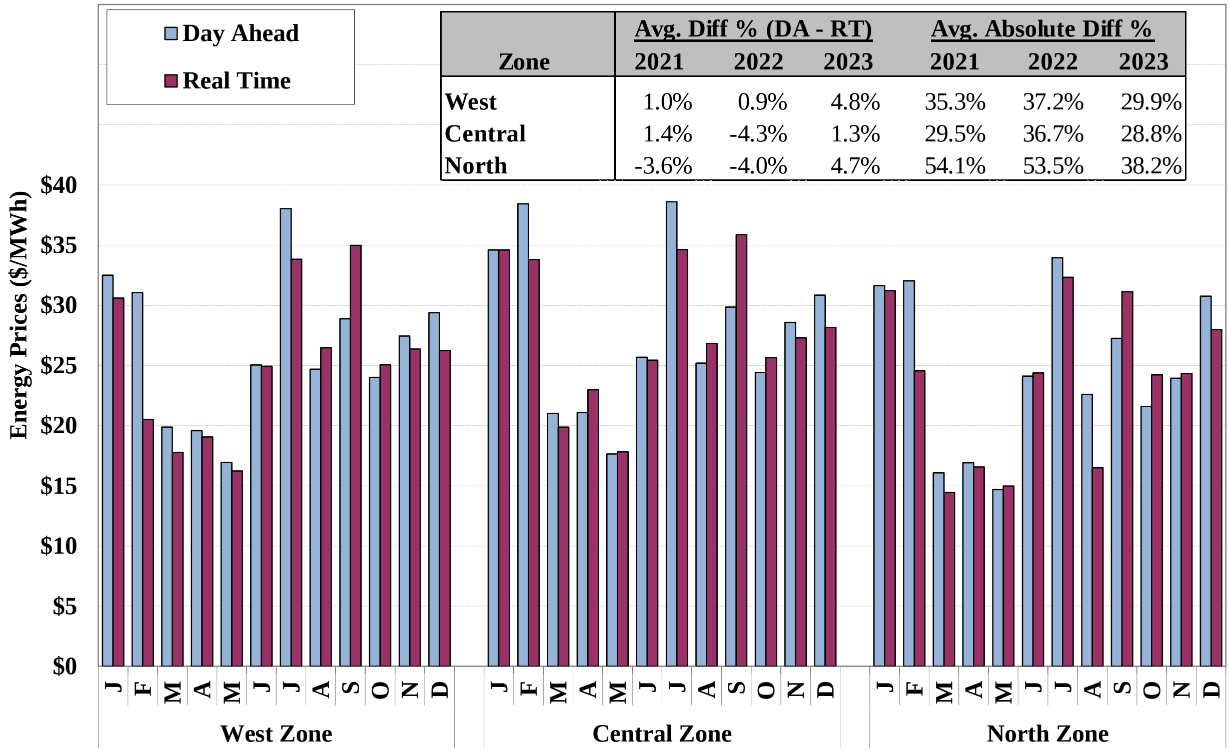
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the consistency of average day-ahead and real-time energy prices at individual nodes throughout the state.

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.

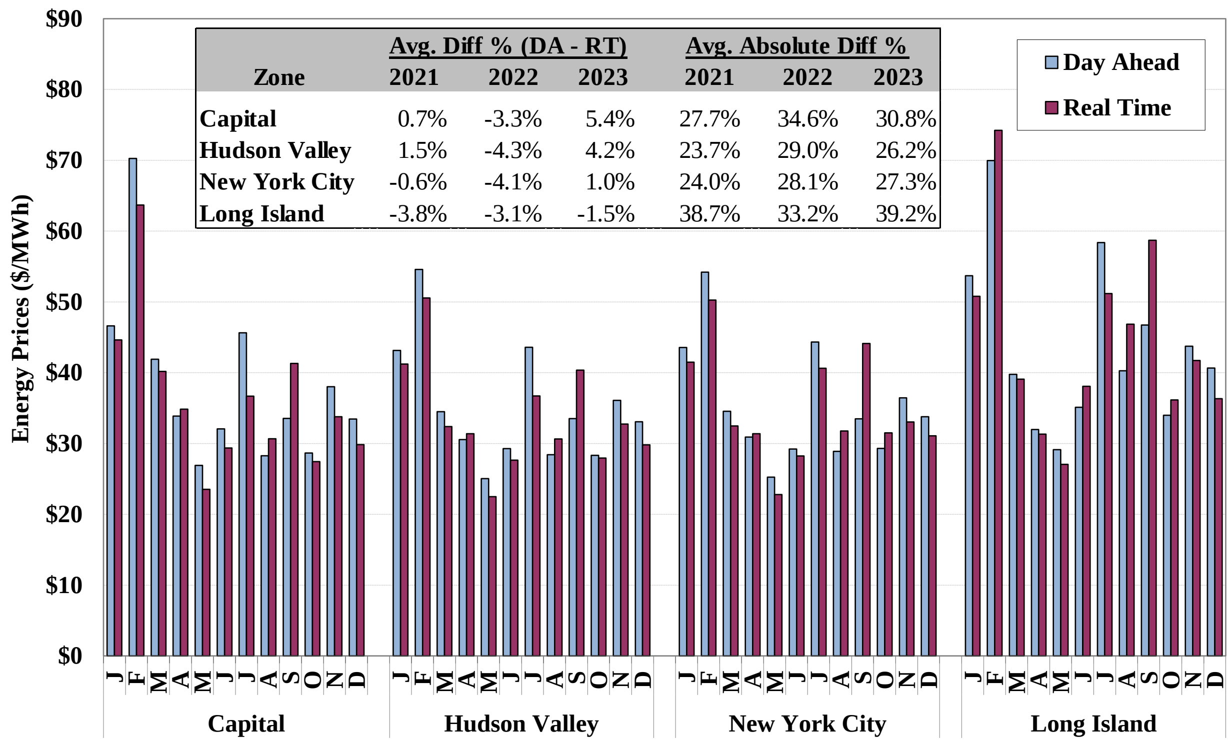
Figure A-17 and Figure A-18 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead 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.

Figure A-17: Average Day-Ahead and Real-Time Energy Prices in Western New York
West, Central, and North Zones – 2023



Zone	Avg. Diff % (DA - RT) 2021	2022	2023	Avg. Absolute Diff % 2021	2022	2023
West	1.0%	0.9%	4.8%	35.3%	37.2%	29.9%
Central	1.4%	-4.3%	1.3%	29.5%	36.7%	28.8%
North	-3.6%	-4.0%	4.7%	54.1%	53.5%	38.2%

Figure A-18: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2023



Zone	Avg. Diff % (DA - RT) 2021	2022	2023	Avg. Absolute Diff % 2021	2022	2023
Capital	0.7%	-3.3%	5.4%	27.7%	34.6%	30.8%
Hudson Valley	1.5%	-4.3%	4.2%	23.7%	29.0%	26.2%
New York City	-0.6%	-4.1%	1.0%	24.0%	28.1%	27.3%
Long Island	-3.8%	-3.1%	-1.5%	38.7%	33.2%	39.2%

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

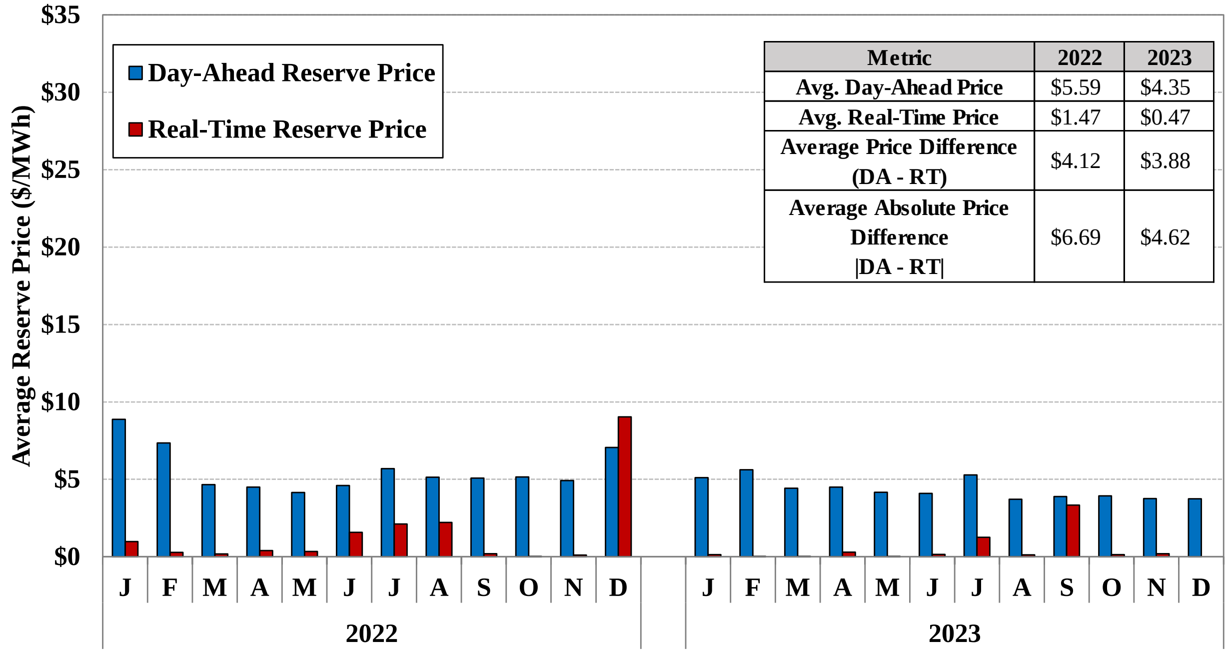
The NYISO co-optimizes the scheduling of energy, operating reserves, and regulation service such that the combined production cost of all products is minimized in the day-ahead and real-time markets. The energy and ancillary services markets place demand on the same supply resources, so prices for energy 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
2022 – 2023



Metric	2022	2023
Avg. Day-Ahead Price	$5.59	$4.35
Avg. Real-Time Price	$1.47	$0.47
Average Price Difference (DA - RT)	$4.12	$3.88
Average Absolute Price Difference |DA - RT|	$6.69	$4.62

Figure A-20: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2022 – 2023

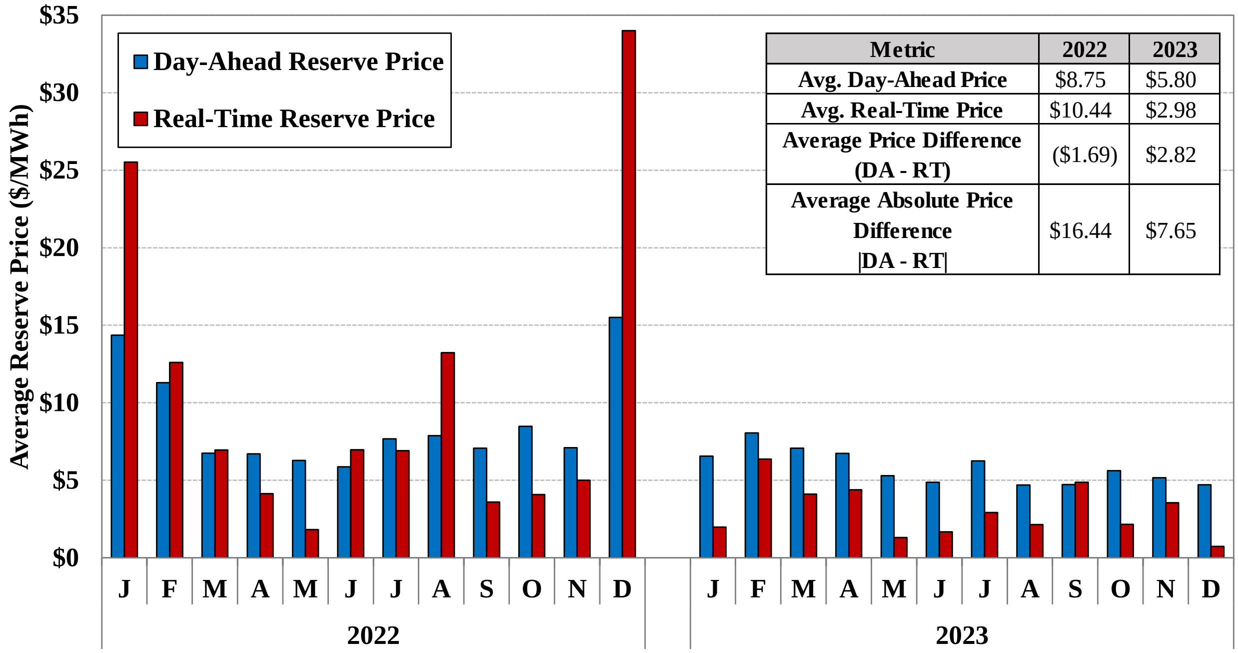
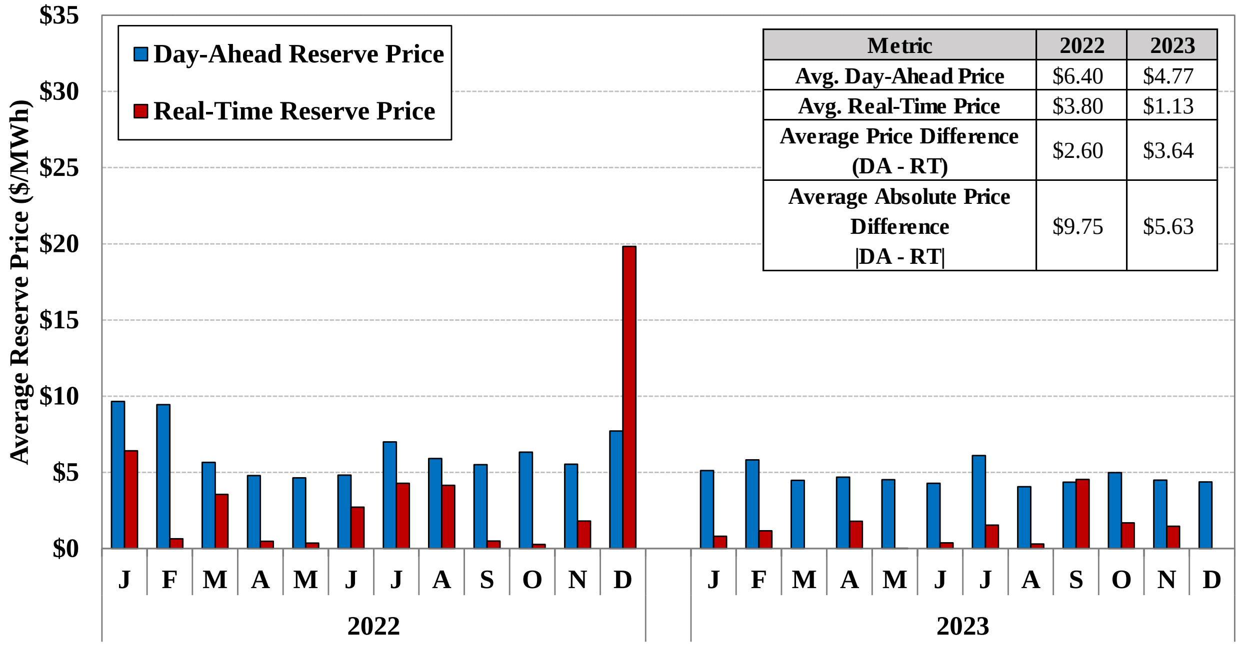


Figure A-21: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2022 – 2023



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.[242] The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

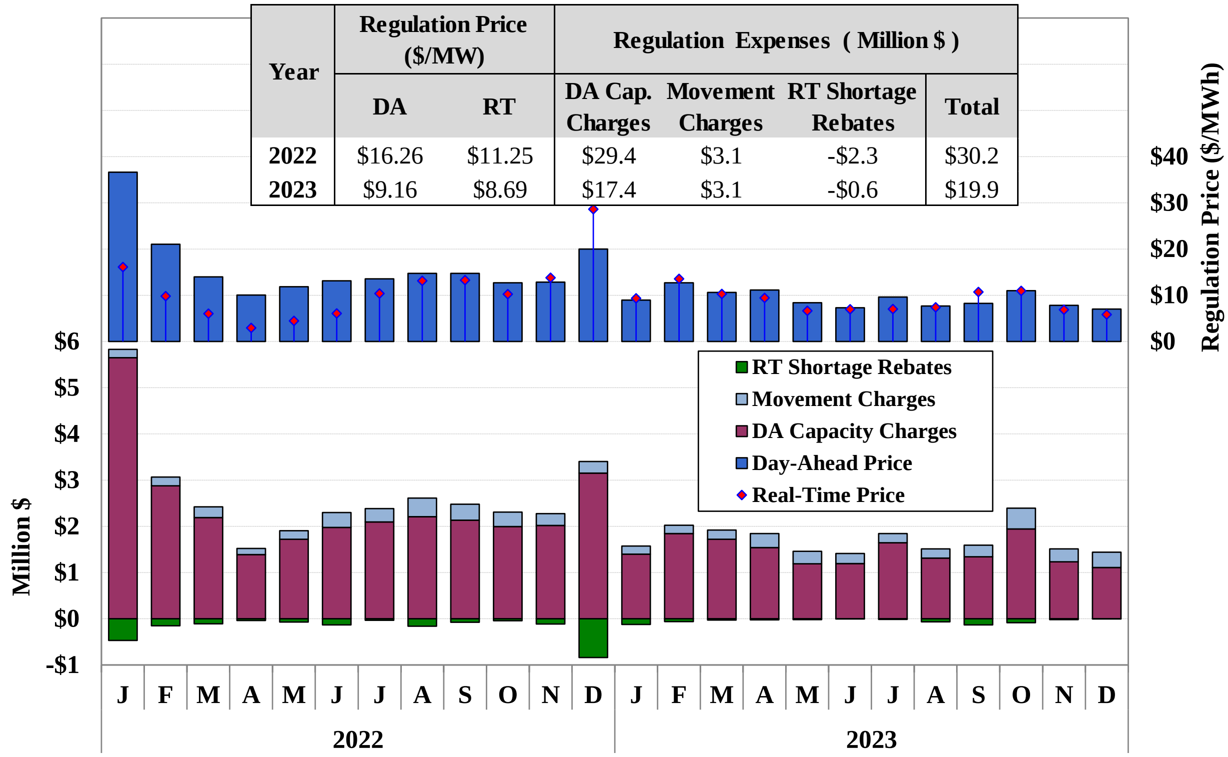
- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.

- 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, 2022 – 2023

Year	Regulation Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2022	$16.26	$11.25	$29.4	$3.1	-$2.3	$30.2
2023	$9.16	$8.69	$17.4	$3.1	-$0.6	$19.9



242 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 examine energy and ancillary services bid and offer patterns to evaluate whether the market is functioning efficiently and whether market participant conduct is consistent with effective competition. 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 that have 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 when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource). Suppliers may also physically withhold by providing inaccurate information regarding the operating characteristics of a resource (e.g., providing an exceedingly long start-up notification time). Economic withholding occurs when a supplier raises the offer price of a resource to reduce its output below competitive levels or otherwise raise the market clearing price. Potential physical and economic withholding are evaluated in subsections A and B.

In the NYISO's market design, the competitive offer of a generator is the marginal cost of producing additional output. Absent market power, a supplier maximizes profits by producing output whenever the production cost is less than the LBMP. However, a supplier with market power profits from withholding when its losses from selling less output are offset by its gains from increasing LBMPs. Accordingly, the NYISO's market power mitigation measures work by capping suppliers' offers at estimates of their marginal costs when their uncapped offers both substantially exceed their estimated marginal cost and would have a material impact on LBMPs. In recent years, marginal cost estimates have become more uncertain during the peak winter periods because of gas scheduling limitations and gas price volatility, so the efficiency of the mitigation measures depend on the accuracy of fuel cost estimates. Market power mitigation by the NYISO is evaluated in subsection C.

The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. This co-optimization causes the prices of both energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. 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 several key operating reserve products in the day-ahead market are evaluated in subsection D.

In addition to screening the conduct of suppliers, it is important to evaluate how the behavior of buyers influences energy prices. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Alternatively, over-scheduling 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.* [243]

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.

243 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.

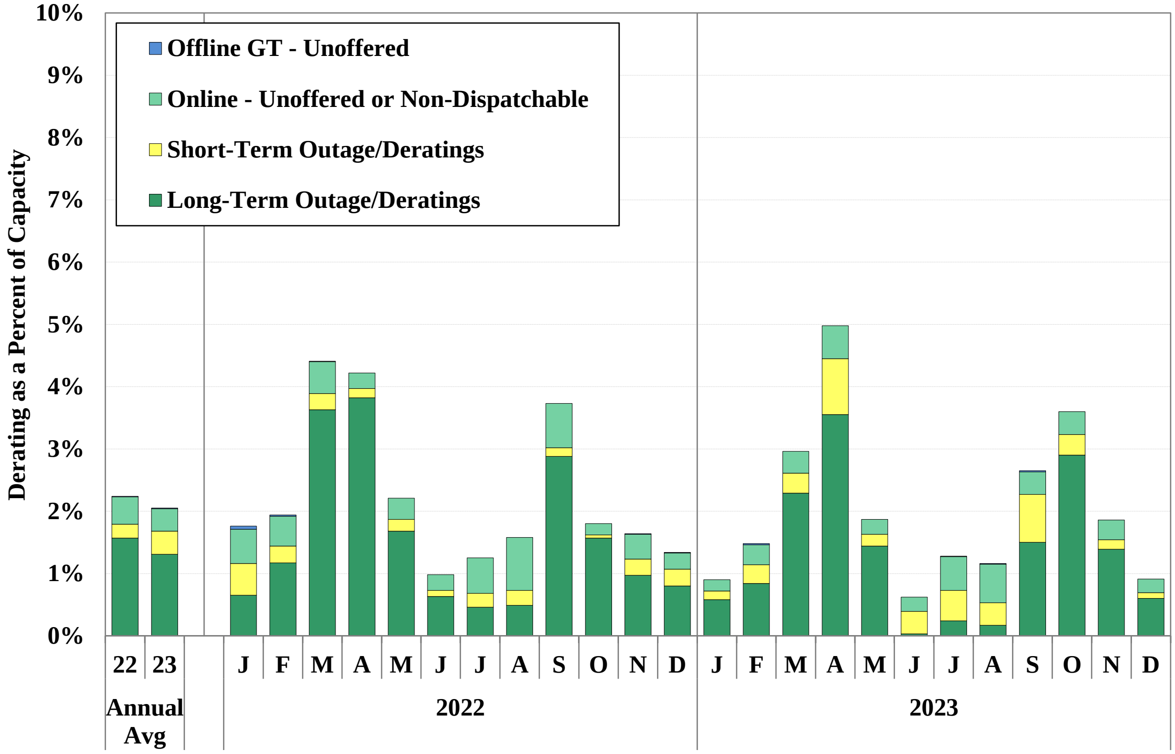
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

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.[244] This assessment determines economic commitment of baseload units based on day-ahead prices, considering start-up, minimum generation, and incremental costs. Economic dispatch of baseload units is based on RTD prices considering ramp rate limitations.[245] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[246]

Figure A-23 - Figure A-24: Unoffered Economic Capacity by Month

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 2022 and 2023.

Figure A-23: Unoffered Economic Capacity by Month in NYCA
2022 – 2023



244 This evaluation includes a modest threshold, which is described in subsection B as "Lower Threshold 1."

245 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.

246 In this paragraph, "prices" refers to both energy and reserves prices.

Figure A-24: Unoffered Economic Capacity by Month in East New York
2022 - 2023

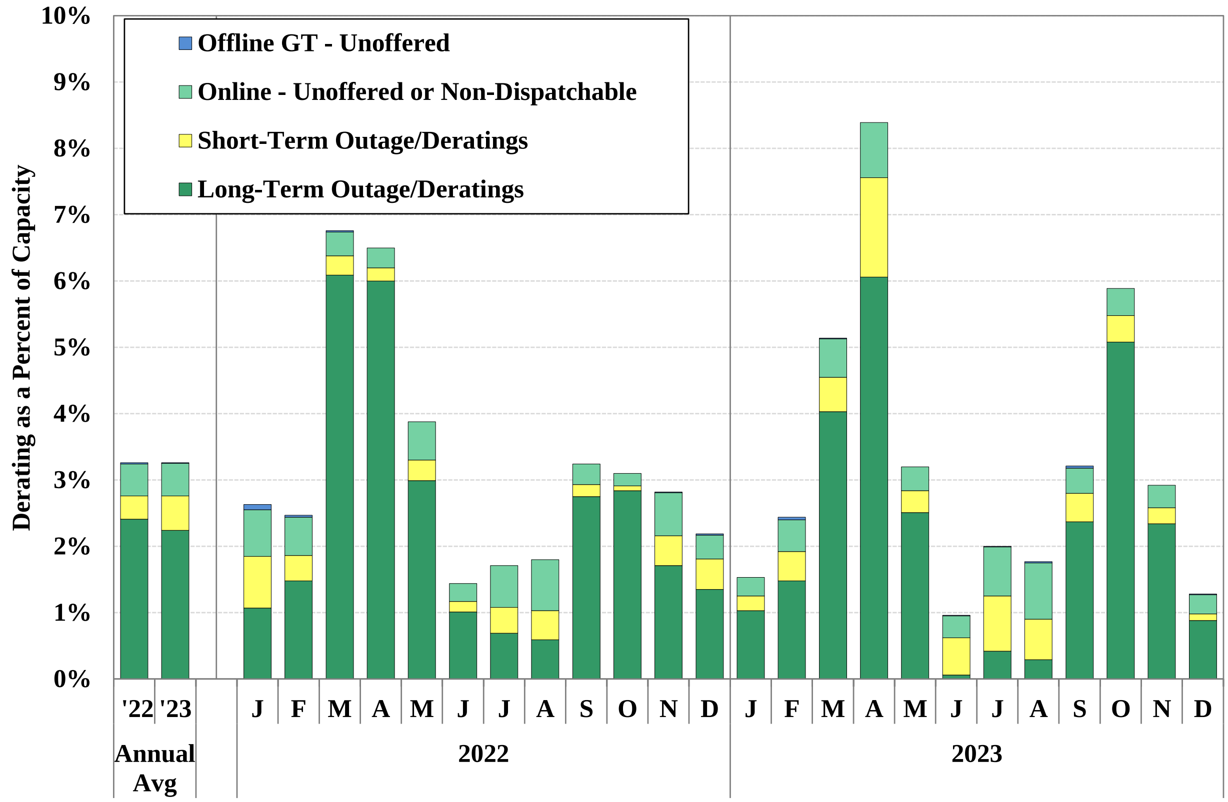


Figure A-25 & Figure A-26: Unoffered Economic Capacity by Load Level & Portfolio Size

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.

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.

Figure A-25: Unoffered Economic Capacity by Supplier by Load Level in New York
2022 – 2023

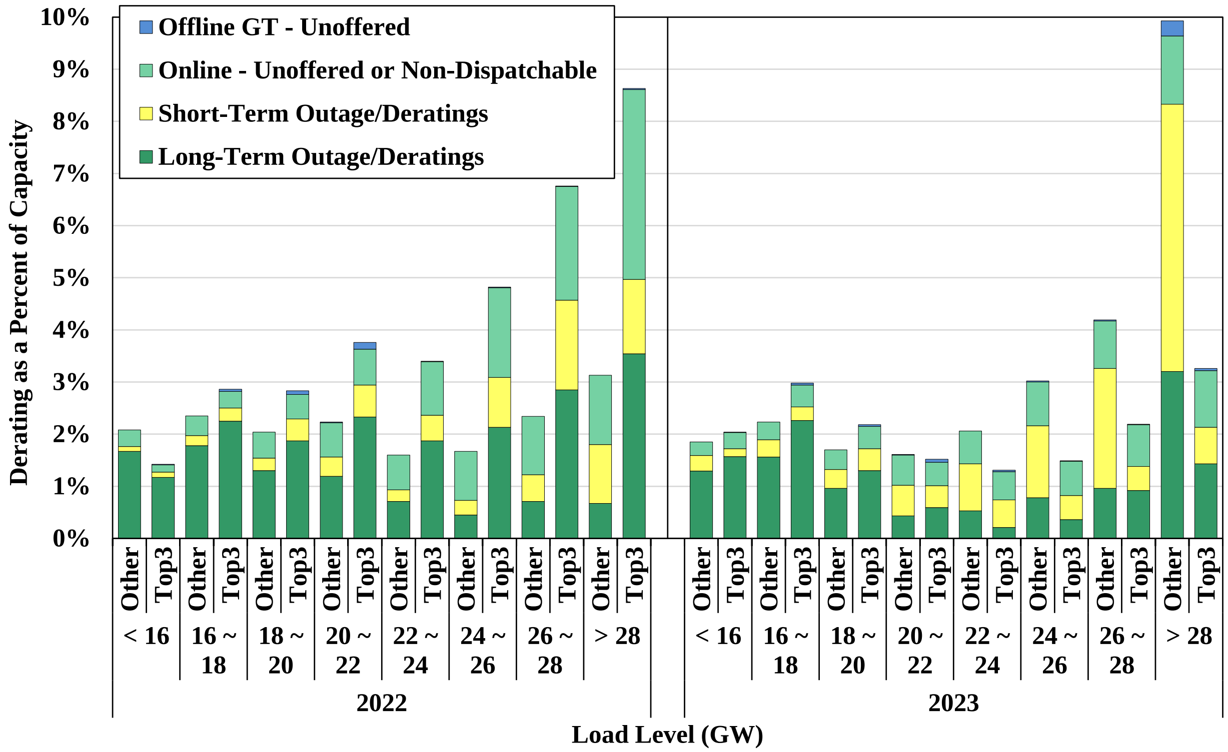
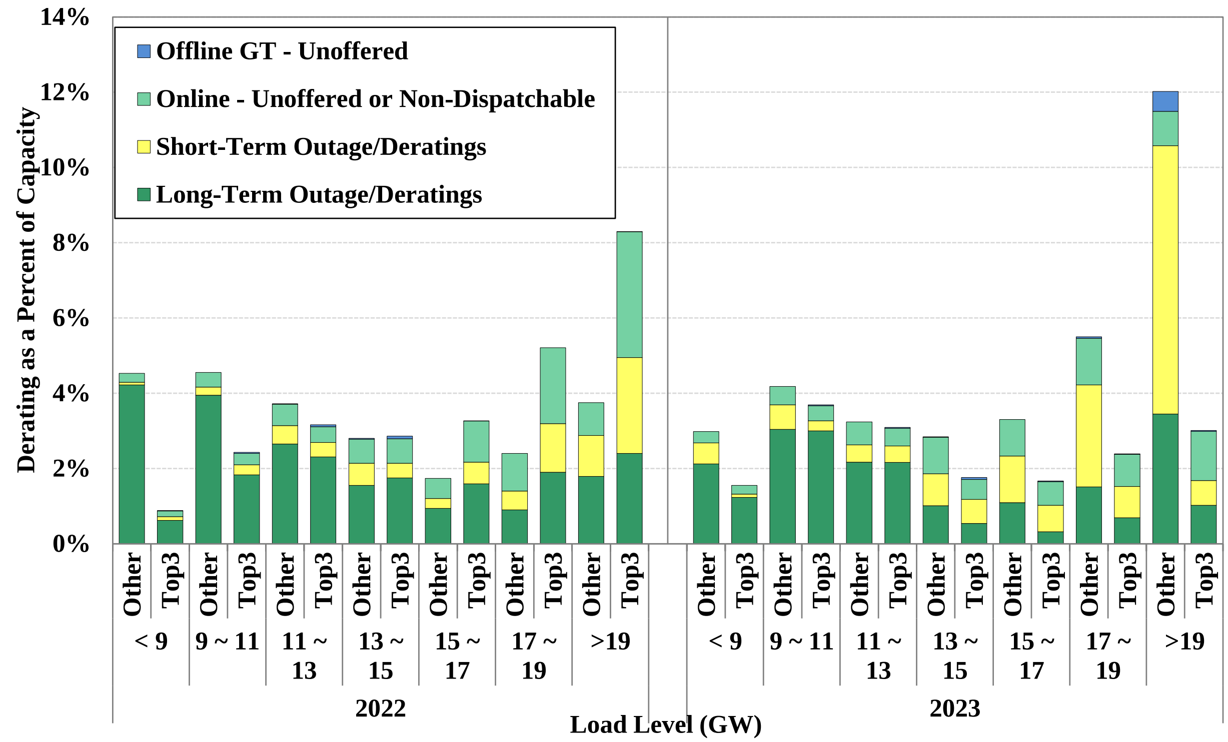


Figure A-26: Unoffered Economic Capacity by Supplier by Load Level in East New York
2022 – 2023



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.

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 its resources 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 actual supply offers with the generator's reference levels, which is an estimate of marginal cost that is used for market power mitigation.[247, 248] 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.[249] 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 standard conduct threshold 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 included to assess

247 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.

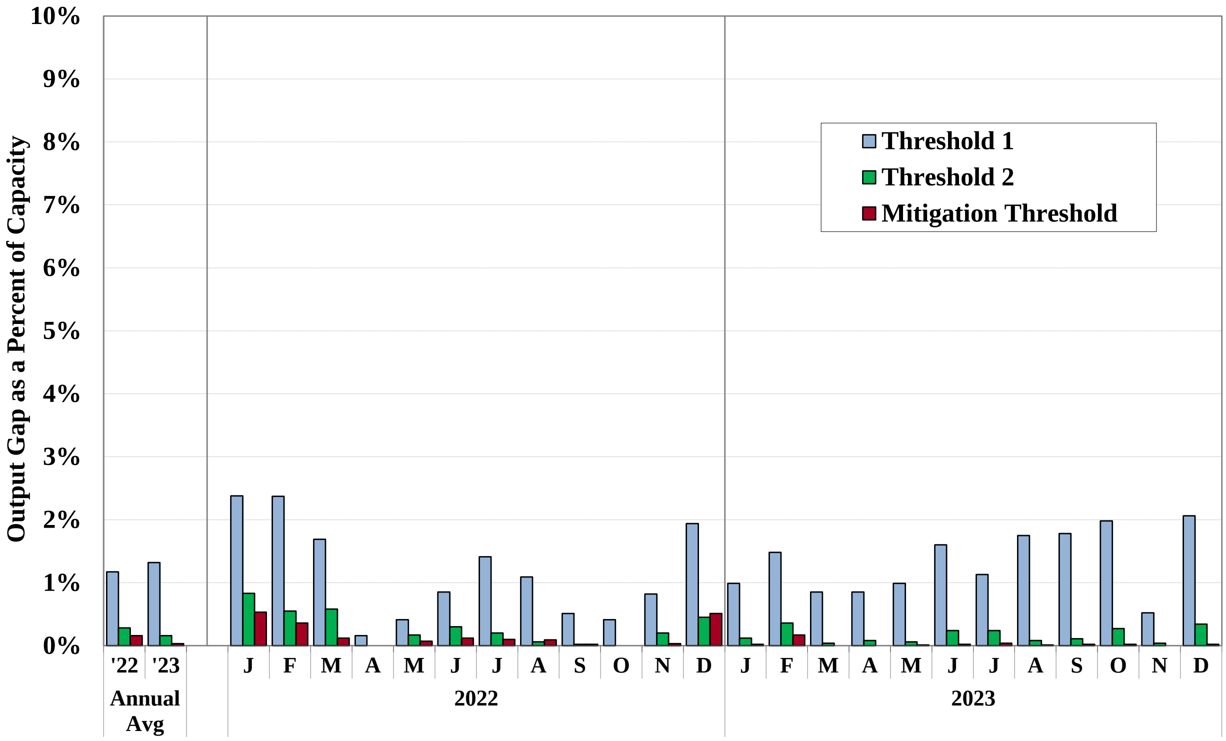
248 Due to the Fuel Cost Adjustment (FCA) functionality, a generator's reference level can be adjusted directly by a generator for a particular hour or day to account for fuel price changes. The NYISO monitors these generator-set FCA reference levels and may request documentation substantiating a generator FCA.

249 The output gap calculation excludes capacity that is more economic to provide ancillary services.

whether there may have been abuse of market power that does not trigger the thresholds specified in the tariff for imposition of mitigation measures by the ISO. However, because there is uncertainty in the estimation of the marginal costs of individual units, results based on these thresholds are more likely to falsely flag behavior that is competitive.[250]

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 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
2022 – 2023



250 In most circumstances, Threshold 1 and Threshold 2 are lower thresholds than the Mitigation Threshold. However, it is sometimes the case that the $100 per MWh mitigation threshold is lower than the 100% value of Threshold 2. This is most common during winter period when gas markets are most volatile.

Figure A-28: Output Gap by Month in East New York
2022 - 2023

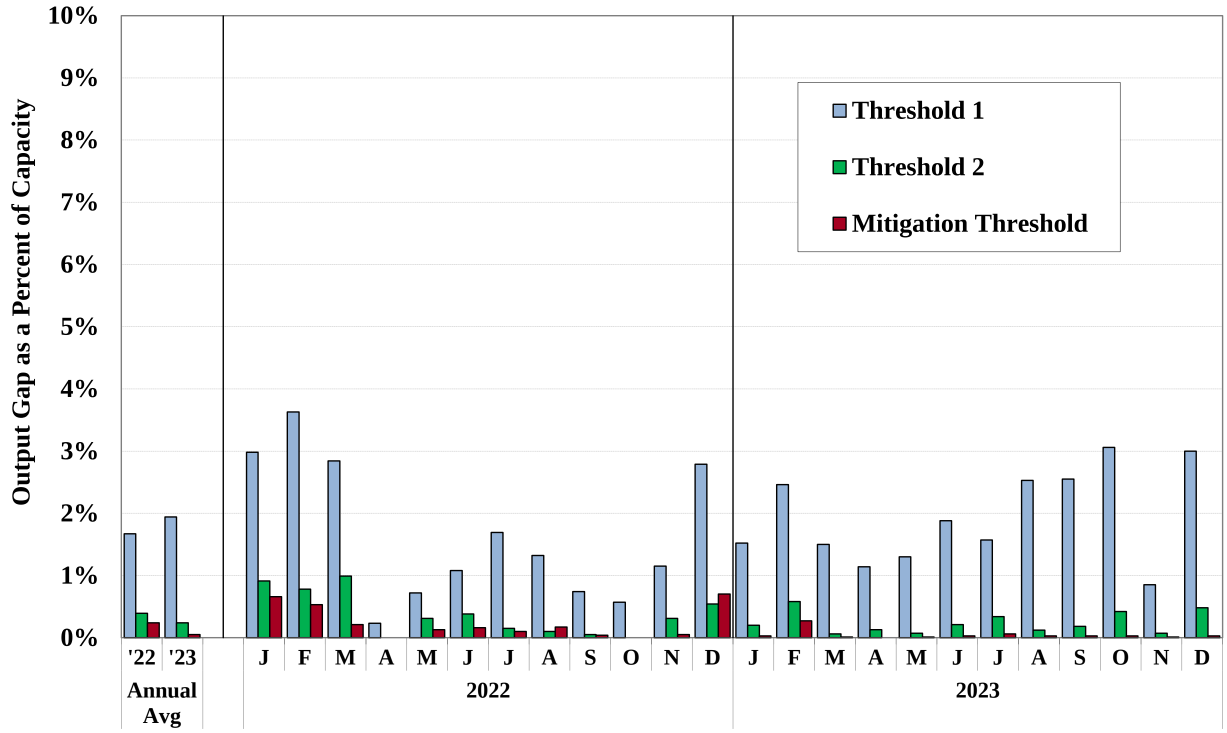


Figure A-29: Output Gap by Supplier by Load Level in New York State
2023

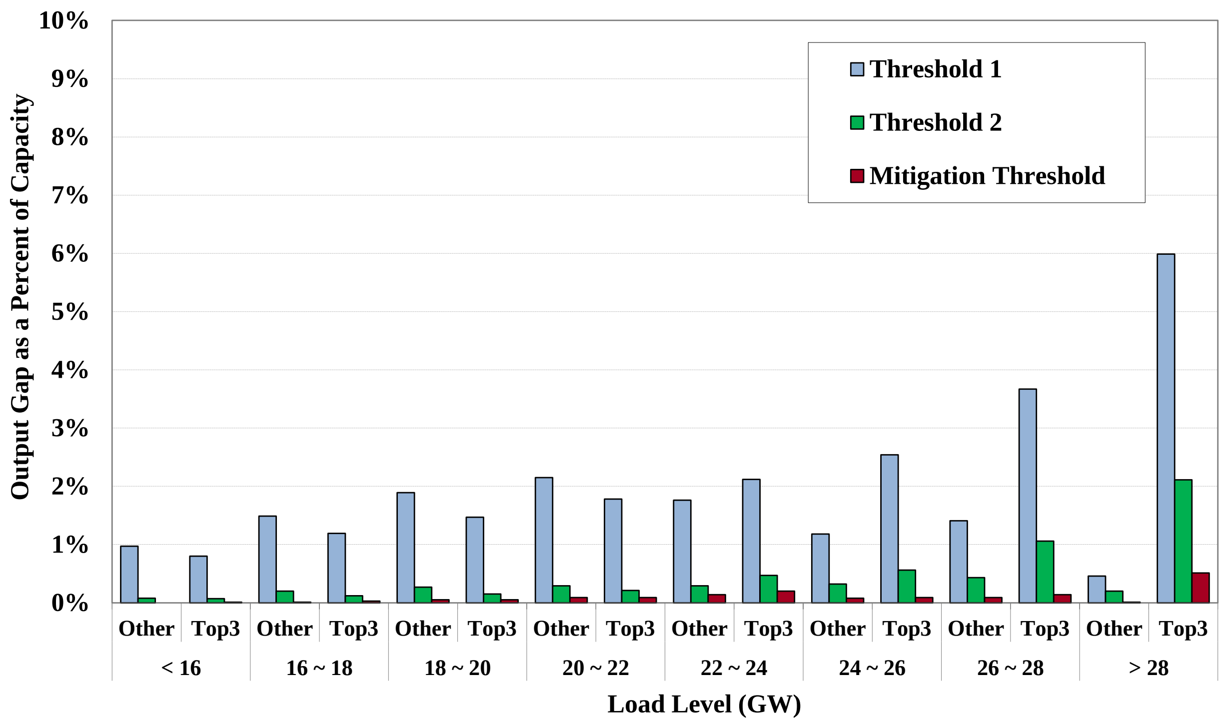
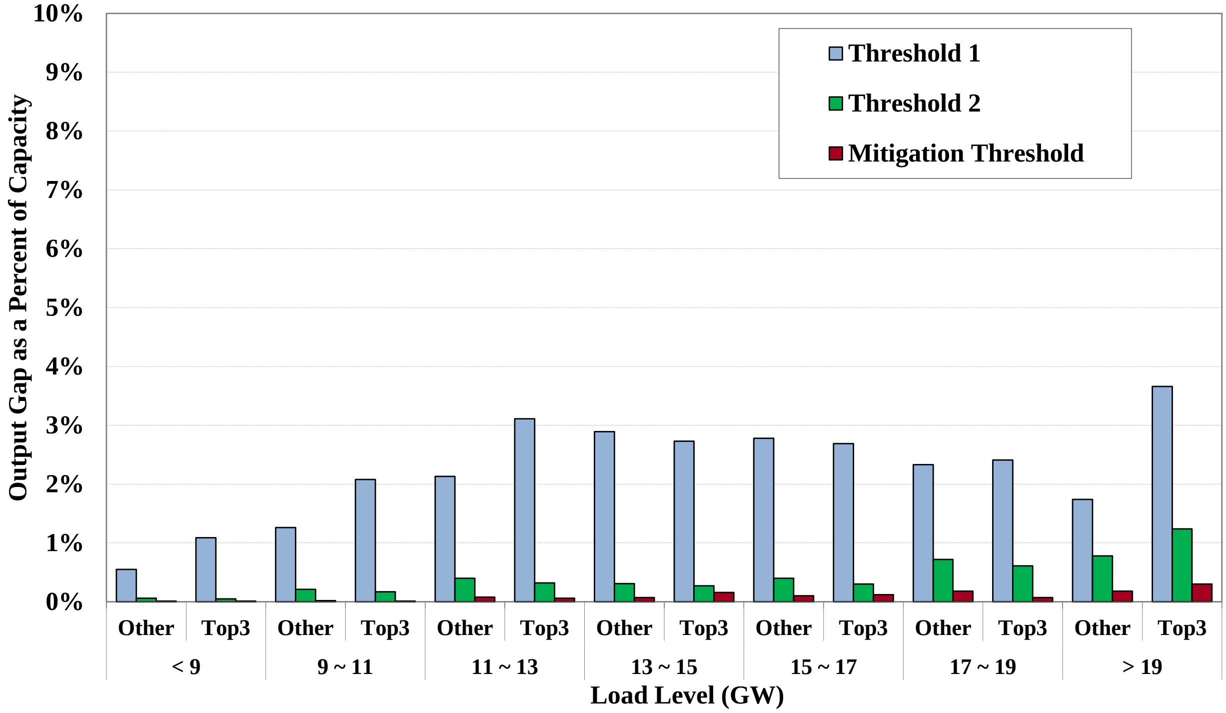


Figure A-30: Output Gap by Supplier by Load Level in East New York
2023



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. The NYISO applies a conduct-impact test 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.[251] 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 the conduct and impact tests and implement the mitigation. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from economic withholding in transmission-constrained areas.

When a transmission constraint is binding, one or more suppliers may be in the 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

251 See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

preceding twelve-month period.[252] 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, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the local area. For this reason, the NYISO has more restrictive conduct and impact thresholds when a single supplier is pivotal for satisfying local reliability criteria outside New York City.[253] The Rest-Of-State Reliability conduct and impact thresholds limit 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.[254]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[255] Reversing a mitigation can occur for several reasons:

- A generator's reference level is inaccurate and the supplier initiated consultation with the 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 the NYISO approved for the generator before the generator was mitigated.[256]
- The generator took appropriate steps to inform the NYISO of a fuel price change prior to being scheduled (either through an FCA or some 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.

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252 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.

253 More restrictive conduct and impact thresholds already existed for New York City generators when they were committed for local reliability. The start-up cost and minimum generation cost offers of such units are effectively subject to $0 thresholds. See NYISO Market Services Tariff, Section 23.5.2.1.

254 See NYISO Market Services Tariff, Section 23.3.1.2.3.

255 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.

256 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.

The 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.[257] 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 2022 and 2023. These figures do not include guarantee payment mitigation that occurs in the settlement system.

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).[258] 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.

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257 See MST Sections 23.2.4.1.2 and 23.3.1.3.

258 Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Figure A-31: Summary of Day-Ahead Mitigation
2022 – 2023

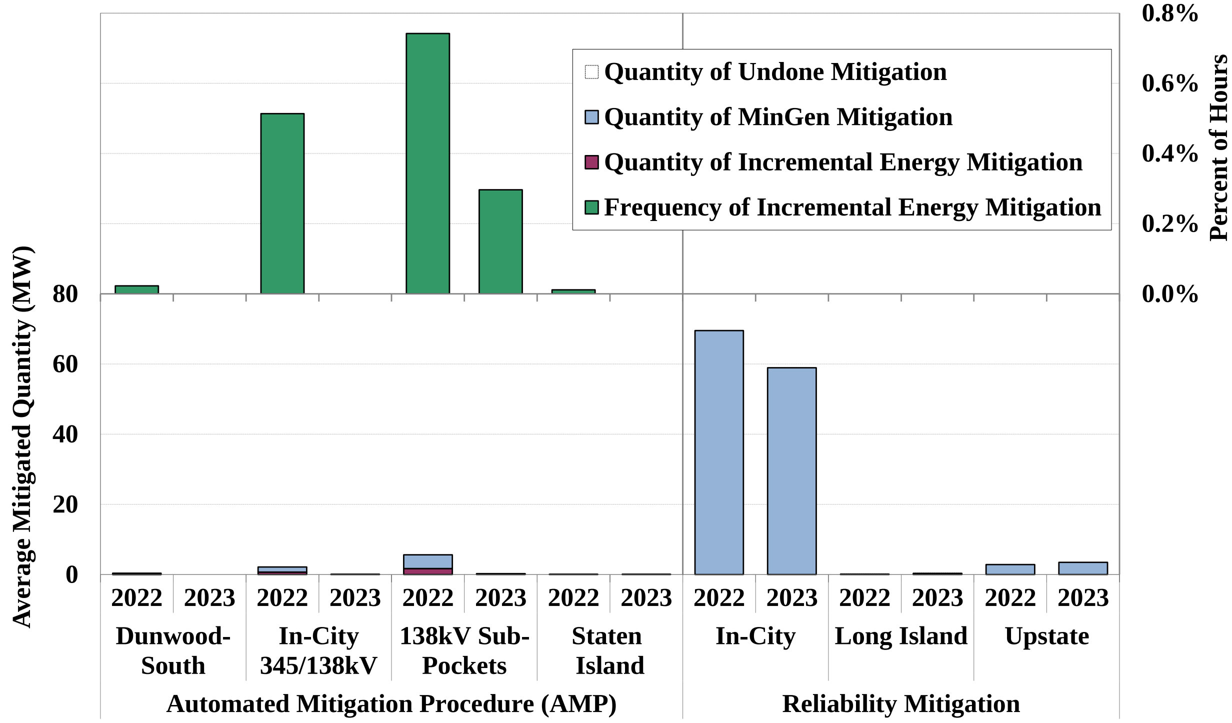
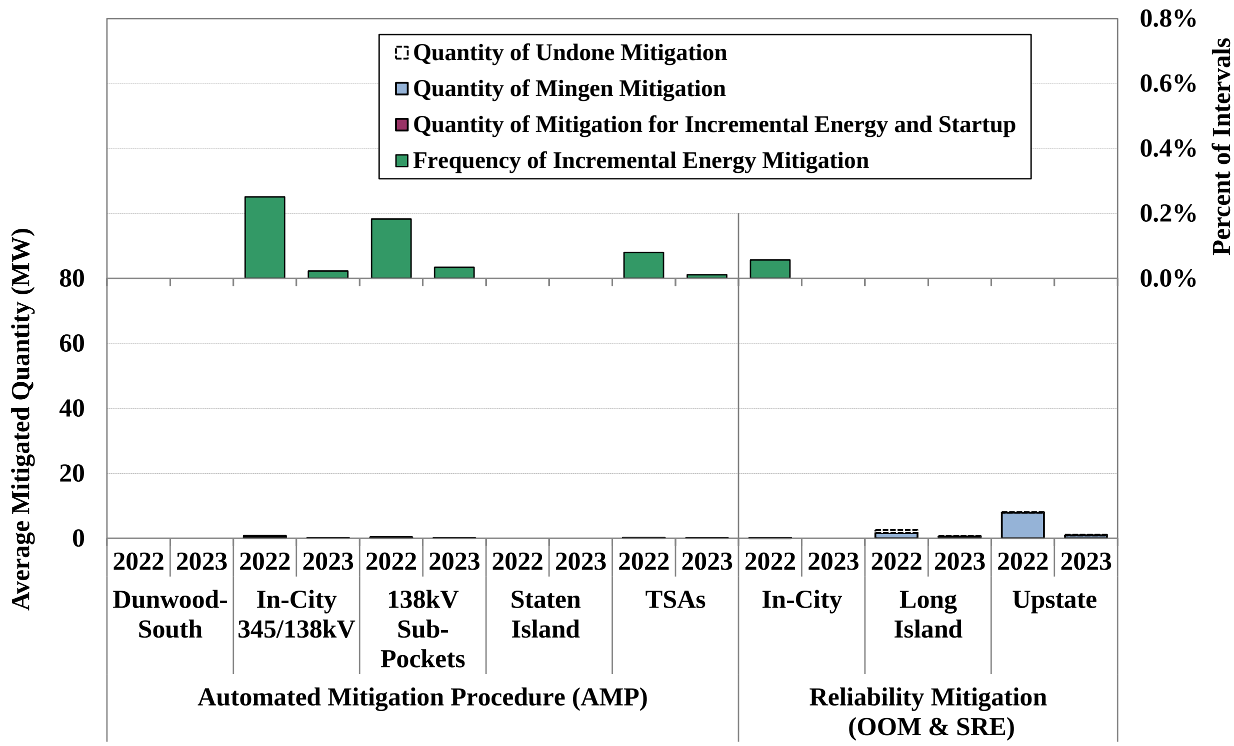


Figure A-32: Summary of Real-Time Mitigation
2022 – 2023



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.

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, 2021 – 2023

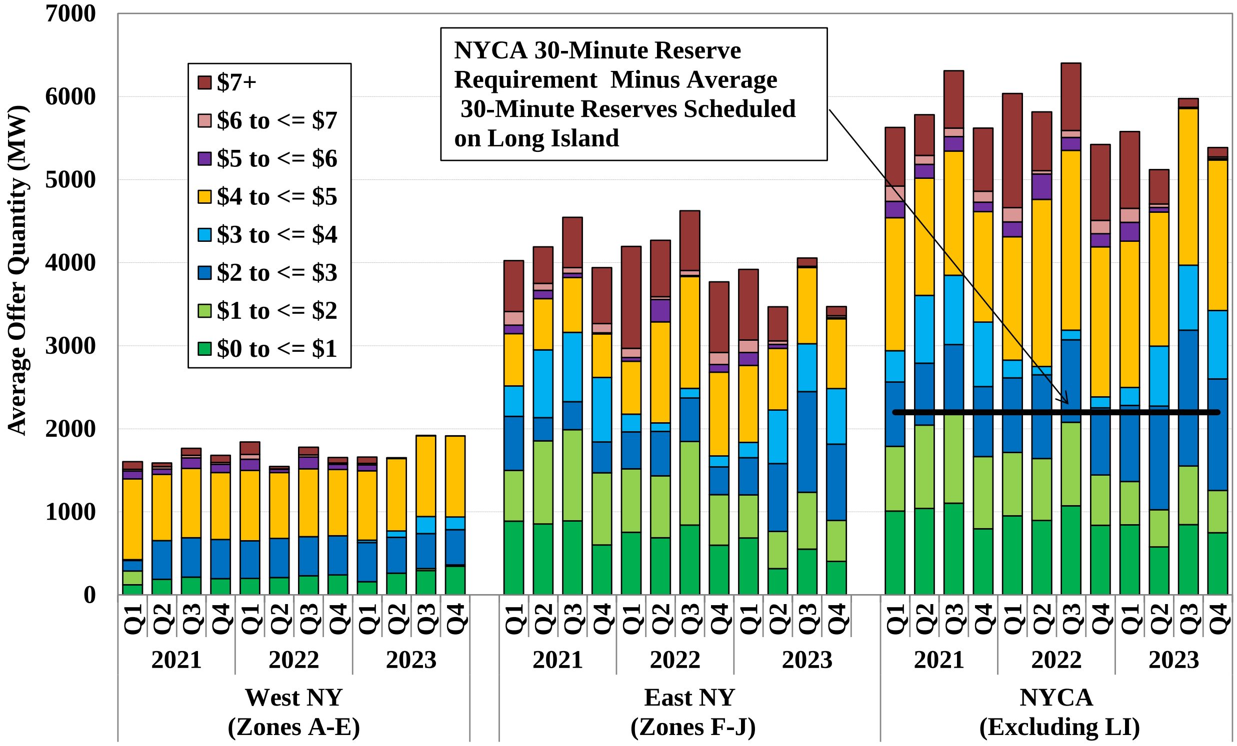
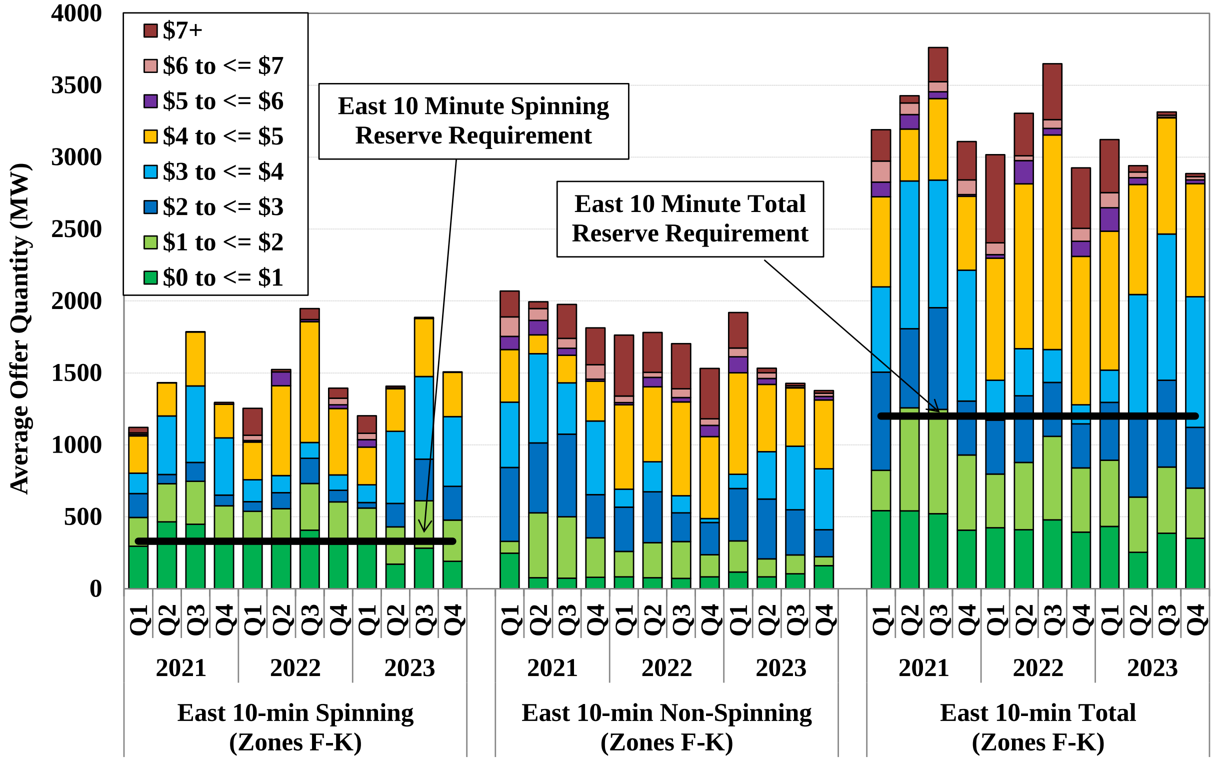


Figure A-34 summarizes offers that can satisfy the Eastern New York reserves requirement and shows generator offers for 10-minute reserves from committed resources and available offline quick-start resources. The first set of stacked bars shows the offers from generators for the 10-minute spinning requirement (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, 2021 – 2023



E. Analysis of Load Bidding and Virtual Trading

In addition to screening the conduct of suppliers for physical and economic withholding, it is important to evaluate how the behavior of buyers influences energy prices. Therefore, we evaluate whether load bidding is consistent with 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 and to settle on the commodity sale privately with their counterparties. It does not represent all of the 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 the equivalent of a load bid with an infinite bid price.
- *Price-Capped Load Bids* – This is load bid into the day-ahead market with a bid price indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[259]
- *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

259 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 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 at the load zone level in New York but not at a more disaggregated 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 are similar to virtual load bids, but they are placed at the external proxy buses rather than at the eleven load zones.

The categories of load listed above are important because they each tend to increase the amount of physical resources that are scheduled in the day-ahead market. Virtual supply and virtual imports, on the other hand, tend to reduce the amount of physical resources that are scheduled in the day-ahead market. Virtual supply is energy that is 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 purchased back from the real-time market.

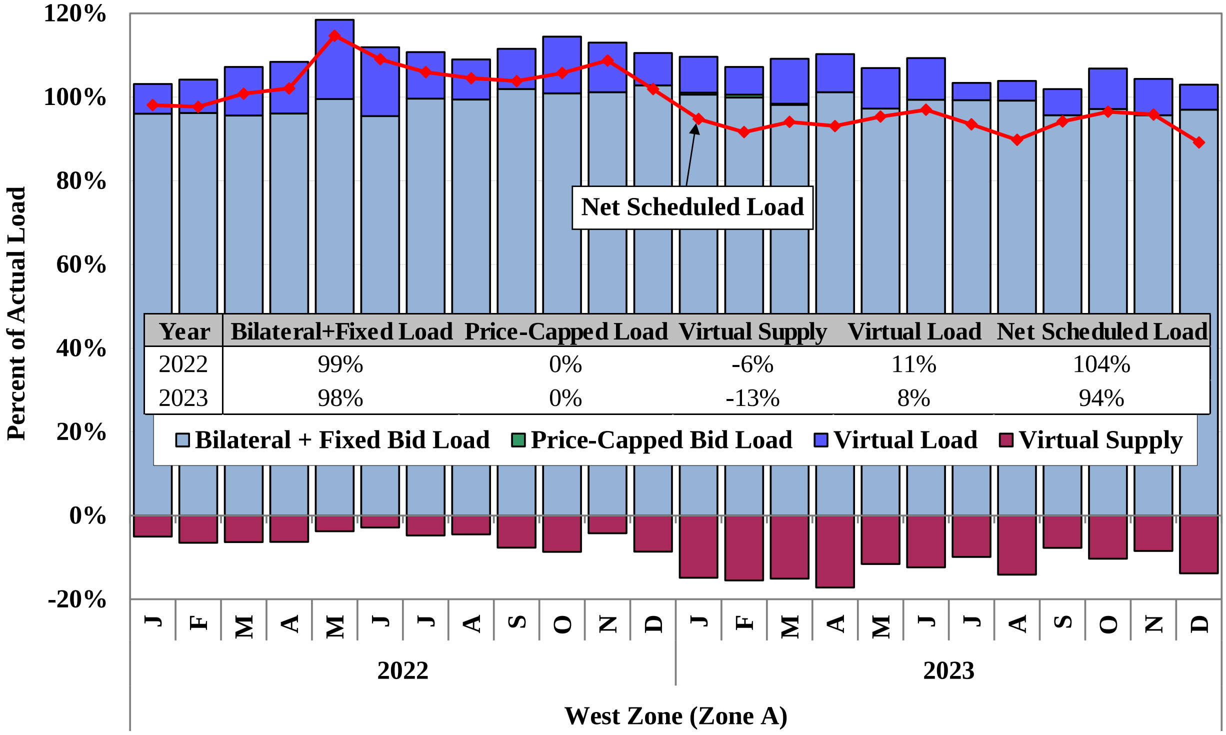
Figure A-35 to Figure A-42: Day-Ahead Load Schedules versus Actual Load

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 before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when it is economic to do so. These suppliers are willing 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 figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

We expect day-ahead load schedules to be generally consistent with actual load in a well-functioning market. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling 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.

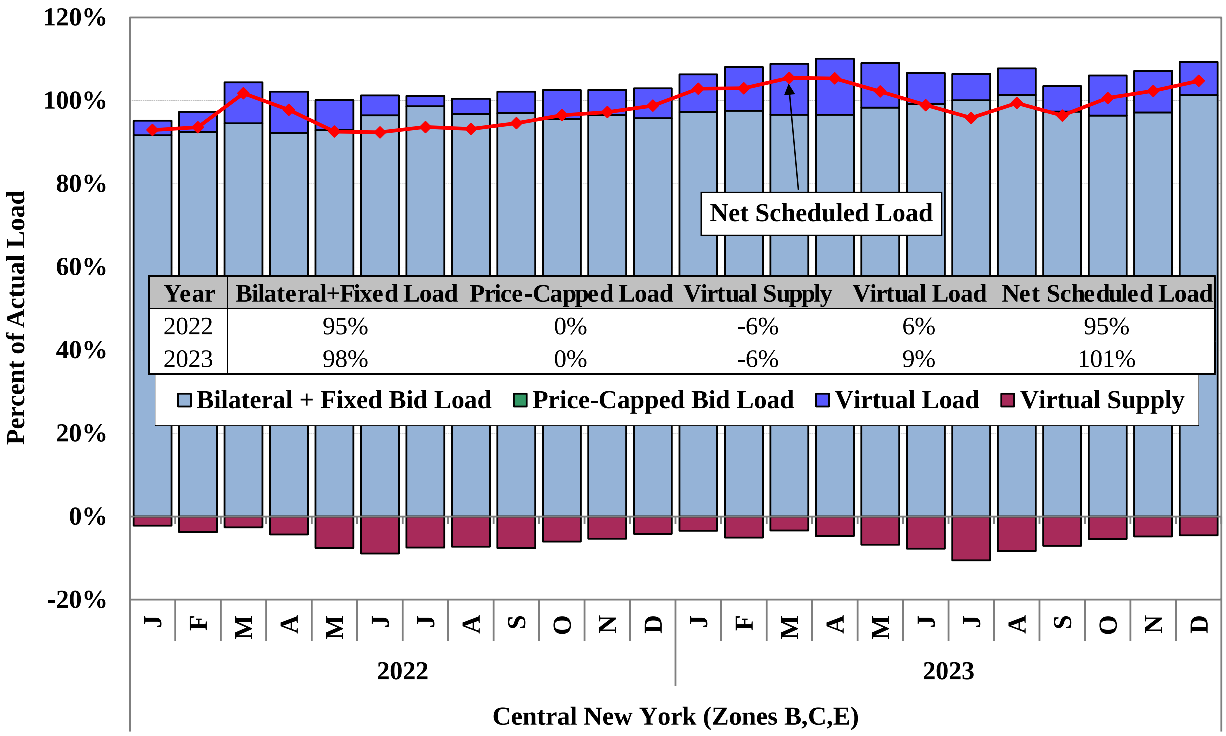
The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2022 and in 2023 at various locations in New York on a monthly average basis. Virtual load (including virtual exports) scheduling has the same effect on day-ahead prices and resource commitment as physical load scheduling, so 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 a negative load for the purposes of this analysis. For each period, physical load and virtual load are shown by bars in the positive direction, while virtual supply is shown 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. The inset table shows the overall changes in scheduling pattern from 2022 to 2023. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-35: Day-Ahead Load Schedules versus Actual Load in West Zone
Zone A, 2022 – 2023



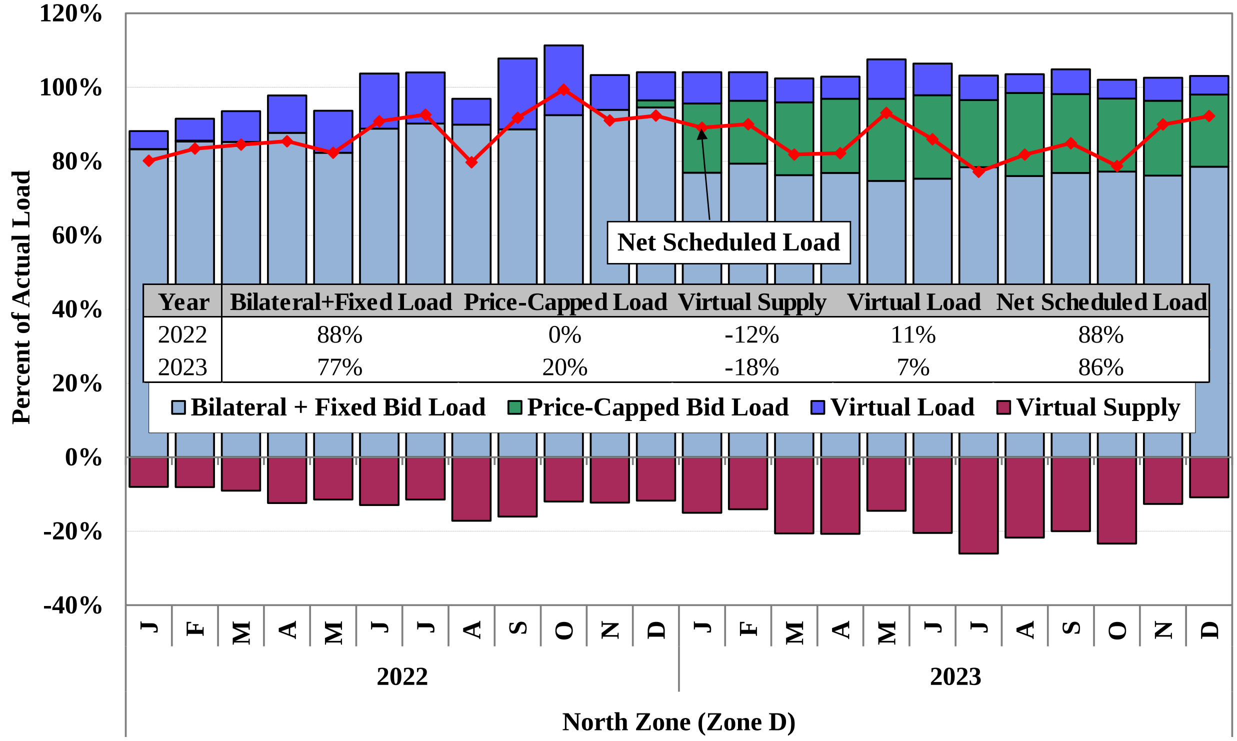
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	99%	0%	-6%	11%	104%
2023	98%	0%	-13%	8%	94%

Figure A-36: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2022 – 2023



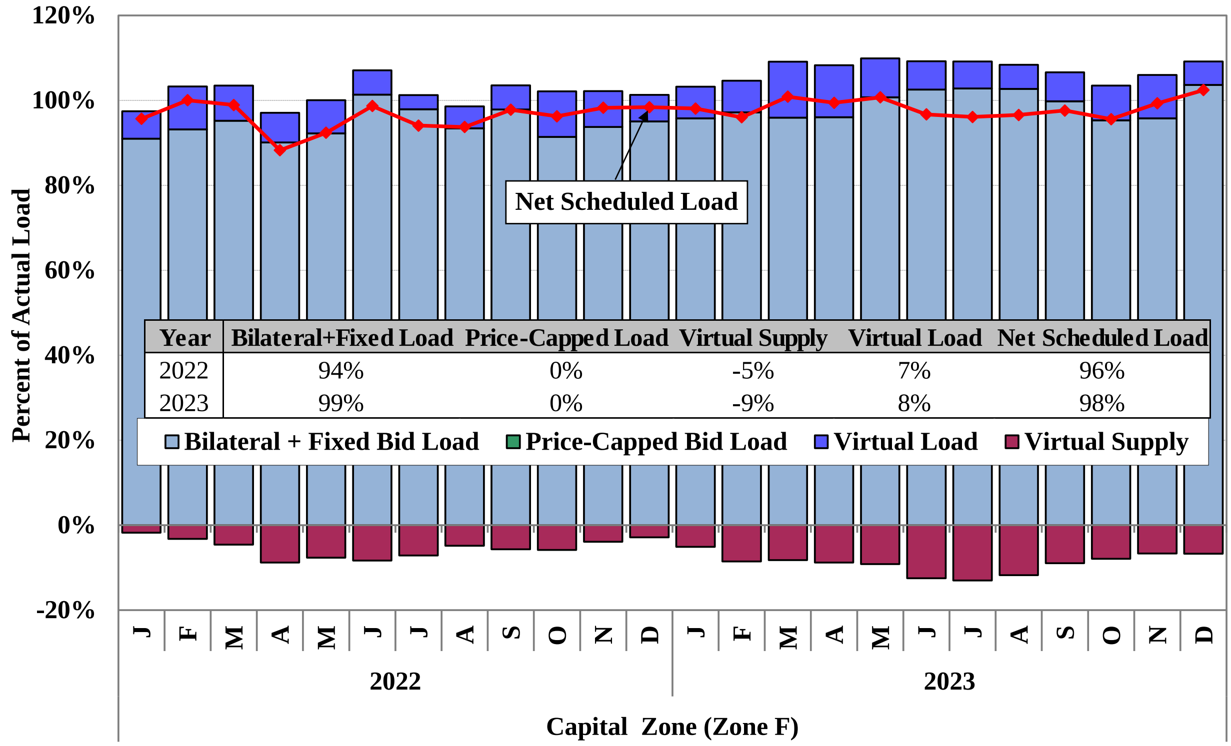
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	95%	0%	-6%	6%	95%
2023	98%	0%	-6%	9%	101%

Figure A-37: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2022 – 2023



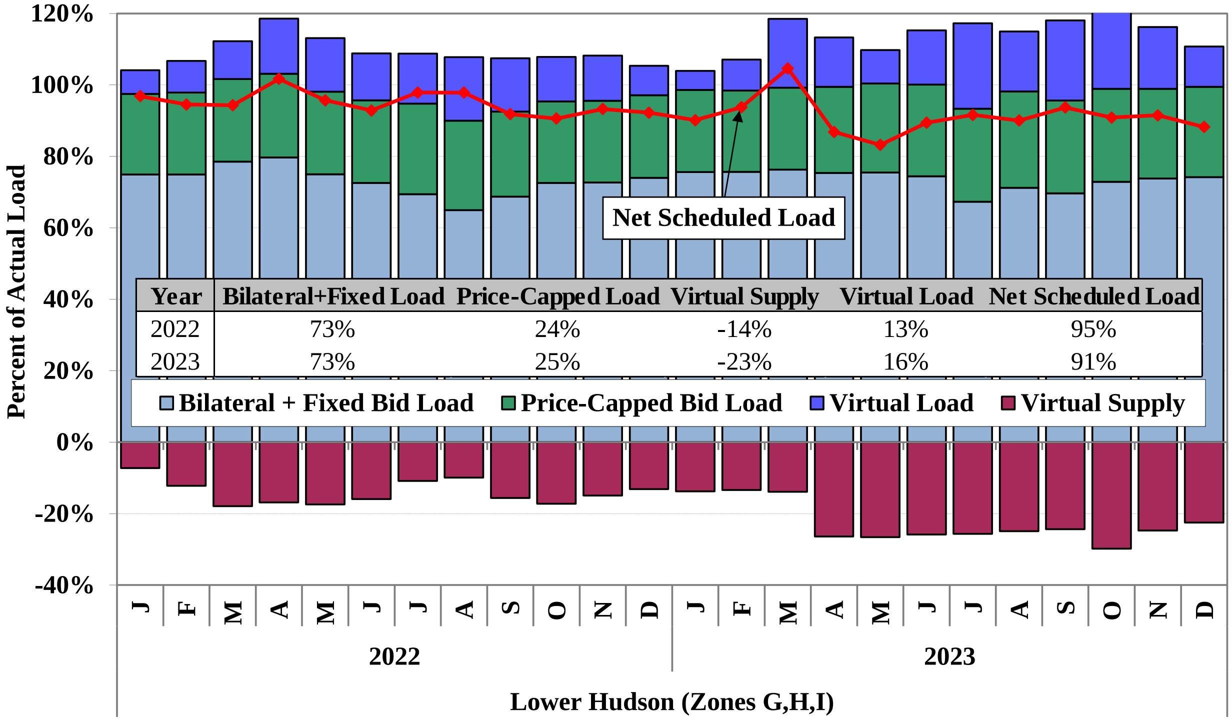
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	88%	0%	-12%	11%	88%
2023	77%	20%	-18%	7%	86%

Figure A-38: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2022 – 2023



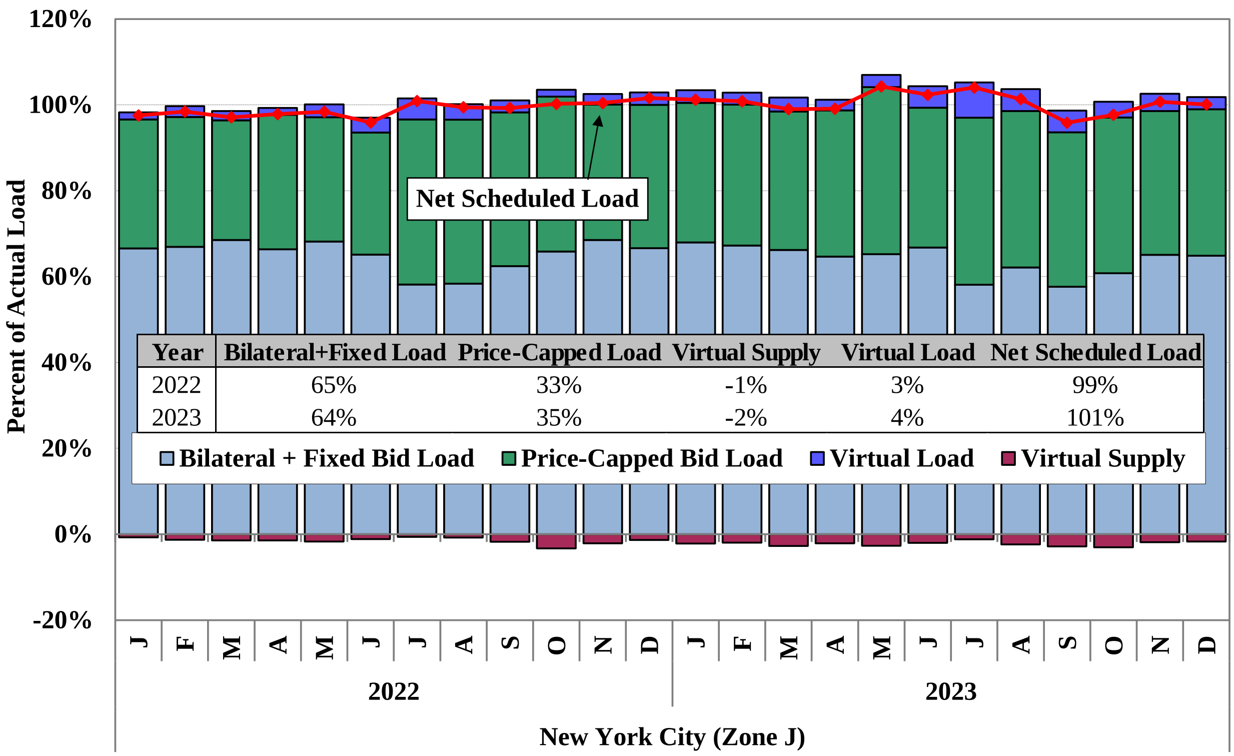
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	94%	0%	-5%	7%	96%
2023	99%	0%	-9%	8%	98%

Figure A-39: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2022 – 2023



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	73%	24%	-14%	13%	95%
2023	73%	25%	-23%	16%	91%

Figure A-40: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2022 – 2023



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2022	65%	33%	-1%	3%	99%
2023	64%	35%	-2%	4%	101%

Figure A-41: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2022 – 2023

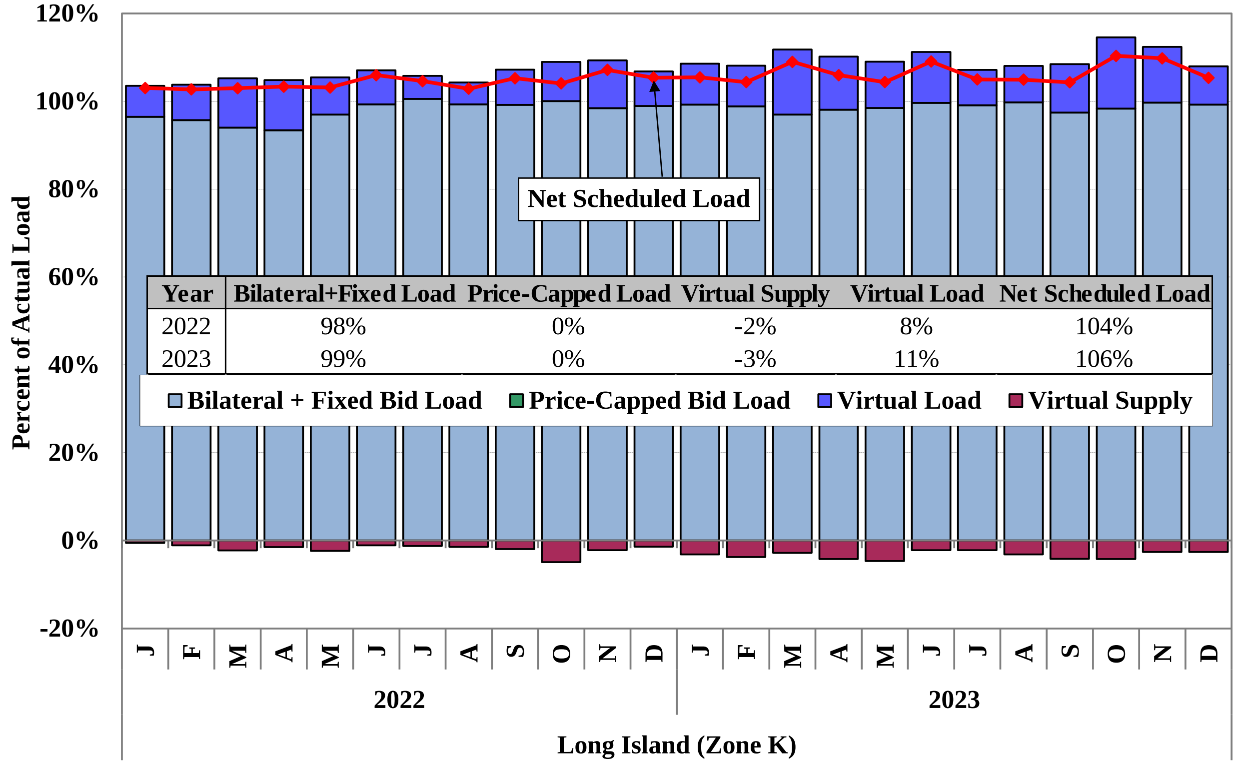
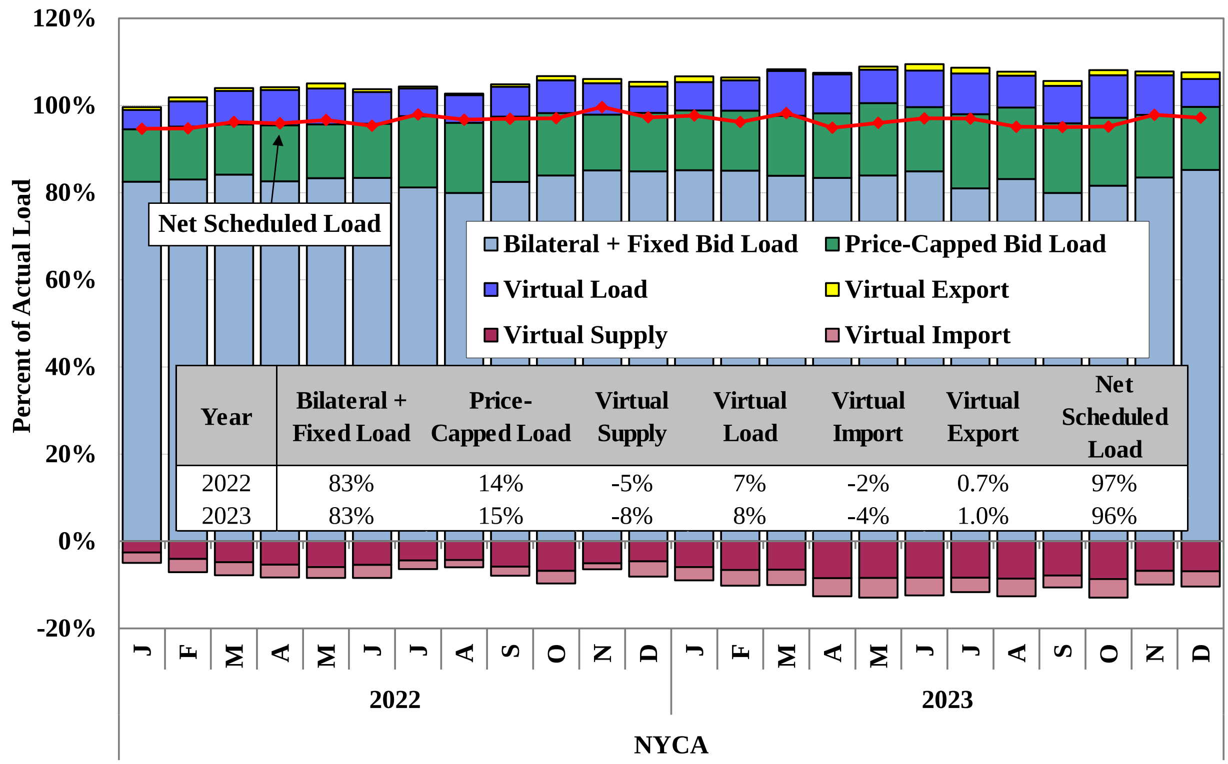


Figure A-42: Day-Ahead Load Schedules versus Actual Load in NYCA
2022 – 2023



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-43: Virtual Trading Volumes and Profitability

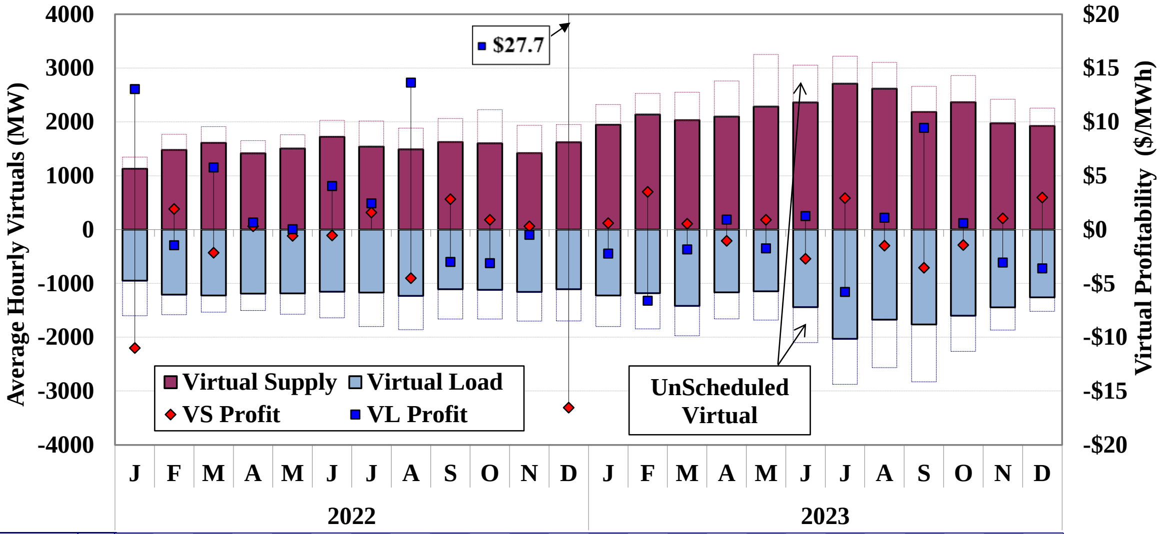
The figure summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2022 and 2023. The amount of scheduled virtual supply in the figure includes scheduled virtual supply at the load 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.[260,261]

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 136 MW of virtual transactions (or 4 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2023. 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.

260 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

261 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.

Figure A-43: Virtual Trading Volumes and Profitability
2022 – 2023



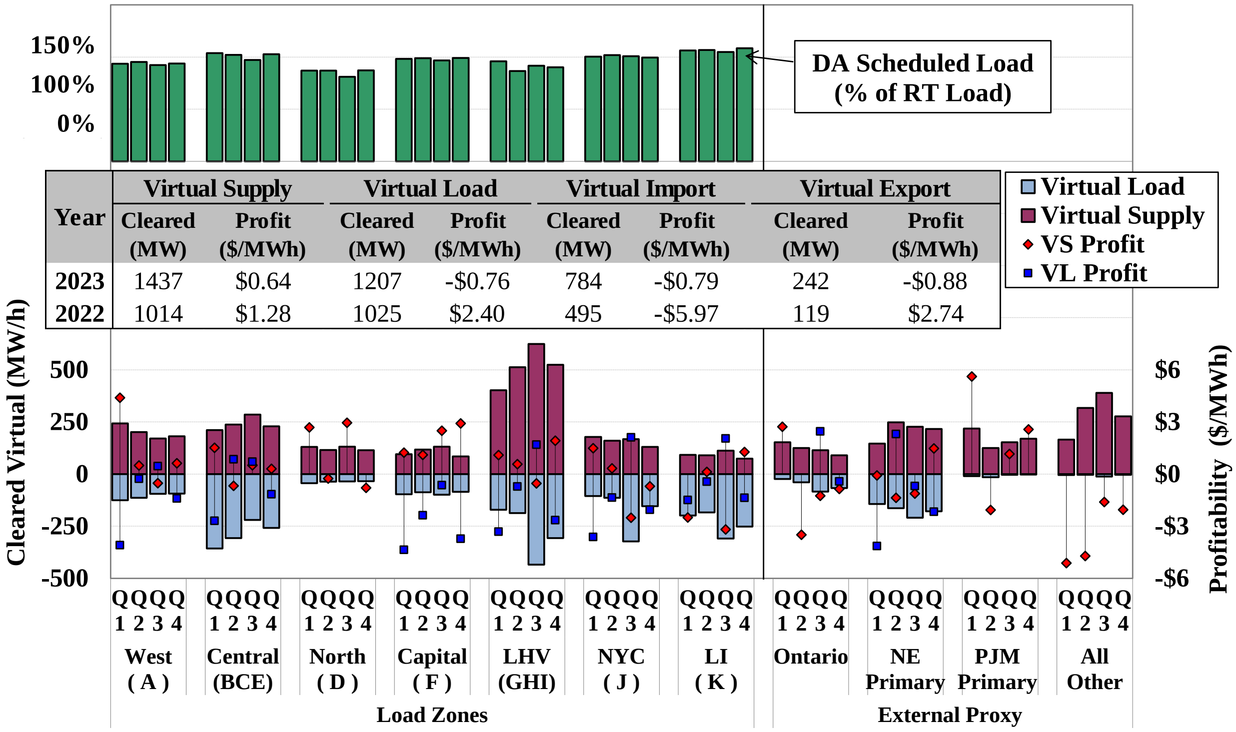
Profit > 50% of Avg. Zone Price	MW	225	307	217	291	324	183	228	153	96	134	250	296	170	455	343	243	275	130	360	243	244	166	198	136
	%	11%	11%	8%	11%	12%	6%	8%	6%	4%	5%	10%	11%	5%	14%	10%	7%	8%	3%	8%	6%	6%	4%	6%	4%
Loss > 50% of Avg. Zone Price	MW	208	278	226	306	304	180	183	124	109	163	289	274	206	412	377	285	296	164	415	322	156	213	255	141
	%	10%	10%	8%	12%	11%	6%	7%	5%	4%	6%	11%	10%	7%	12%	11%	9%	9%	4%	9%	8%	4%	5%	7%	4%

Figure A-44: Virtual Trading Activity

Figure A-44 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 2023. The upper portion of the figure shows the average day-ahead scheduled load (as a percent of real-time load) at each geographic region. The table in the middle compares the overall virtual trading activity in 2022 and 2023.

Figure A-44: Virtual Trading Activity[262]
by Region by Quarter, 2023



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)
2023	1437	$0.64	1207	-$0.76	784	-$0.79	242	-$0.88
2022	1014	$1.28	1025	$2.40	495	-$5.97	119	$2.74

262 Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW.

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. The 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 the 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.[263]

In addition to day-ahead congestion revenues, the 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.[264] 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 the 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.[265] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead

263 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).

264 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).

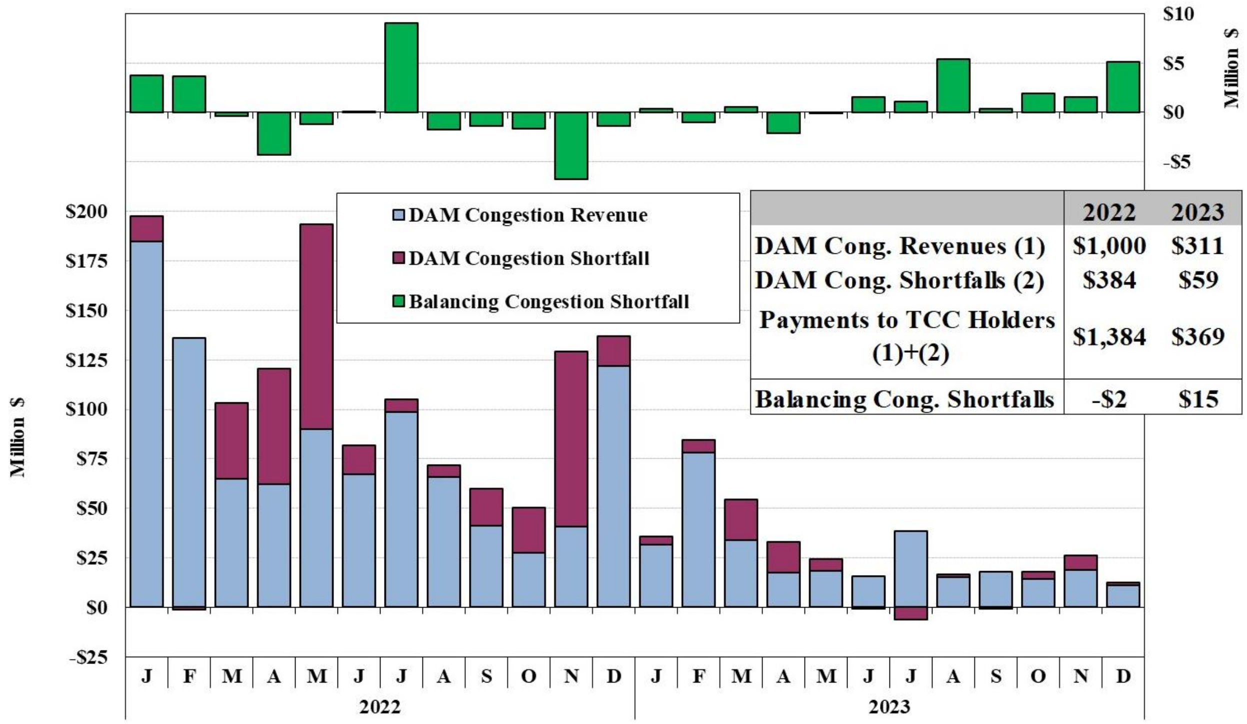
265 For example, suppose 120 MW of TCCs are sold across a particular line. If 100 MW is scheduled to flow when the constraint has a shadow price of $50/MWh in an hour in the day-ahead market, the NYISO will have a day-ahead congestion shortfall of $1,000 in that hour ((120 MW – 100 MW) * $50/MWh).

congestion revenues. These shortfalls are partly offset by the revenues from selling excess TCCs.

Figure A-45: Congestion Revenue Collections and Shortfalls

Figure A-45 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2022 and 2023. 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-45: Congestion Revenue Collections and Shortfalls
2022 - 2023



B. Congestion on Major Transmission Paths

Transmission lines that move power from the low-cost to high-cost parts of the state provide considerable value. For instance, supply resources in Eastern New York are generally more expensive than those in Western New York, but the majority of the load is located in Eastern New York. Consequently, transmission bottlenecks arise as power flows from Western New York to Eastern New York, 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-46 to Figure A-48: Day-Ahead and Real-Time Congestion by Path

Figure A-46 to Figure A-48 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-46 compares these quantities in 2022 and 2023 on an annual basis, while Figure A-47 and Figure A-48 show the quantities separately for each quarter of 2023. The figures measure congestion in two ways: [266]

- 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.[267]

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, primarily 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.
- NYC Lines in 345 kV system: Lines leading into and within the NYC 345 kV system.
- NYC Lines in Load Pockets: Lines 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.

266 Binding transmission constraints with a shadow cost lower than $0.1/MWh are not included.

267 The shadow cost of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

- External Interface: Congestion related to the total transmission limits or ramp limits of the external interfaces.

Figure A-46: Day-Ahead and Real-Time Congestion by Transmission Path
2022 – 2023

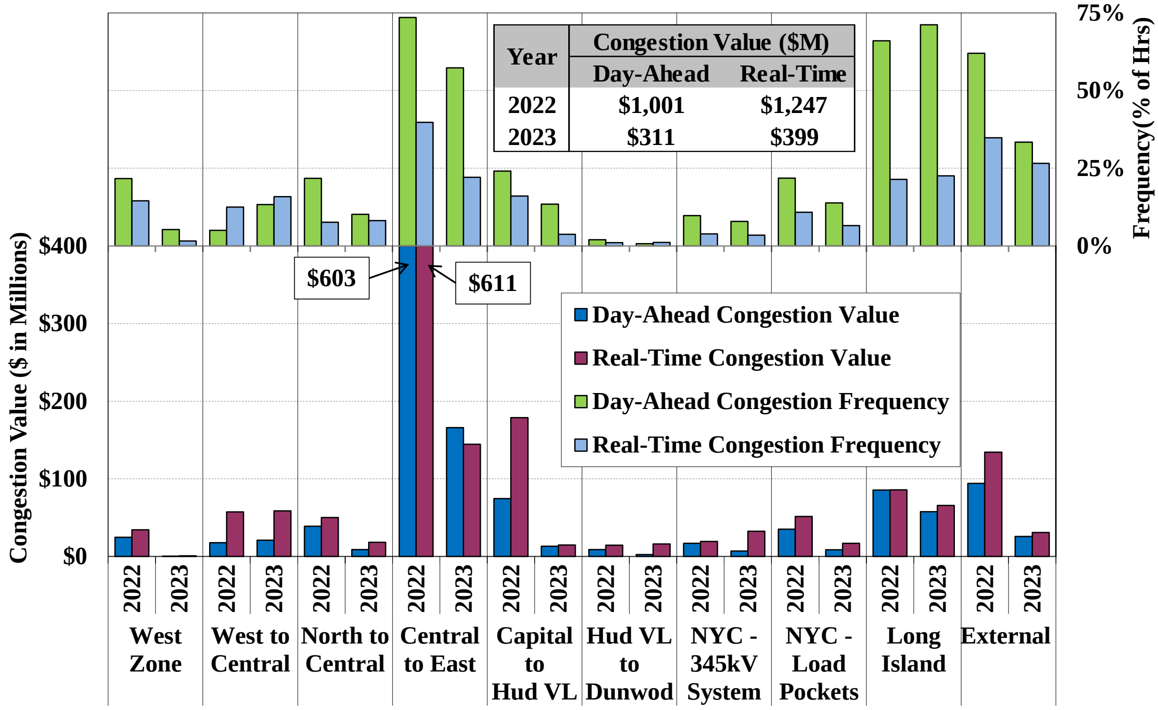


Figure A-47: Day-Ahead Congestion by Transmission Path
By Quarter, 2023

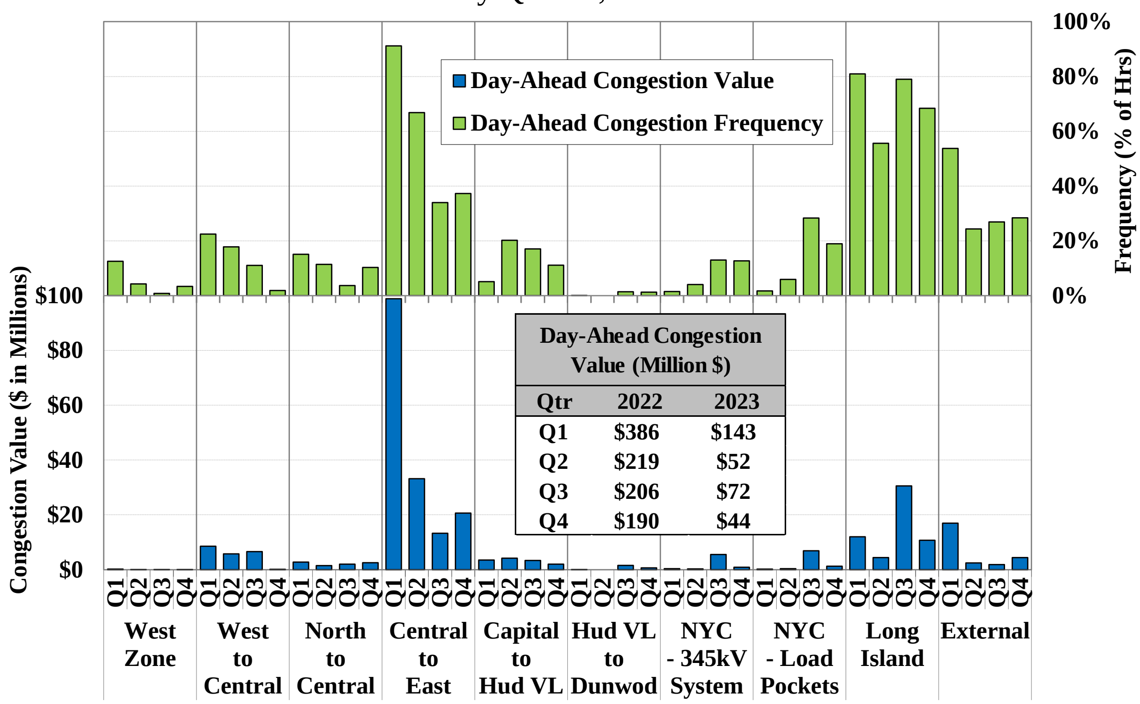
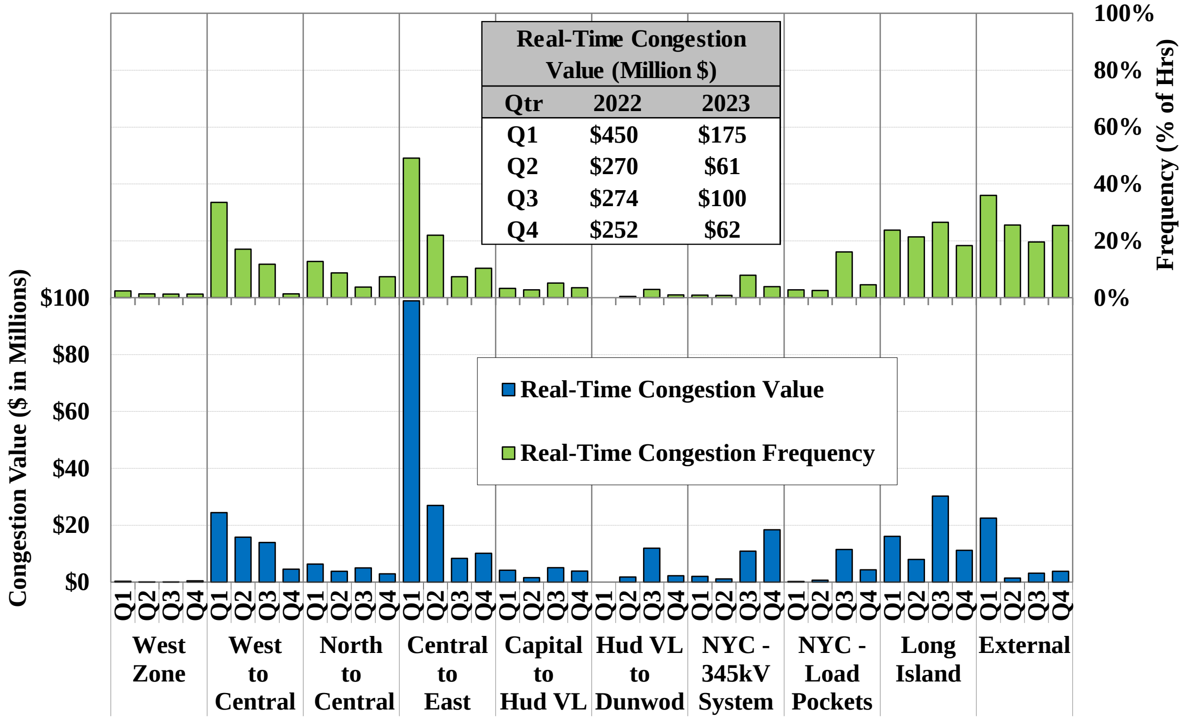


Figure A-48: Real-Time Congestion by Transmission Path
By Quarter, 2023



C. Real-Time Congestion Map by Generator Location

Figure A-49 to Figure A-50: 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-49 and Figure A-50 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,[268] 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 2023, specifically:

- Load-weighted hourly average real-time LBMP at each generator node within the region;

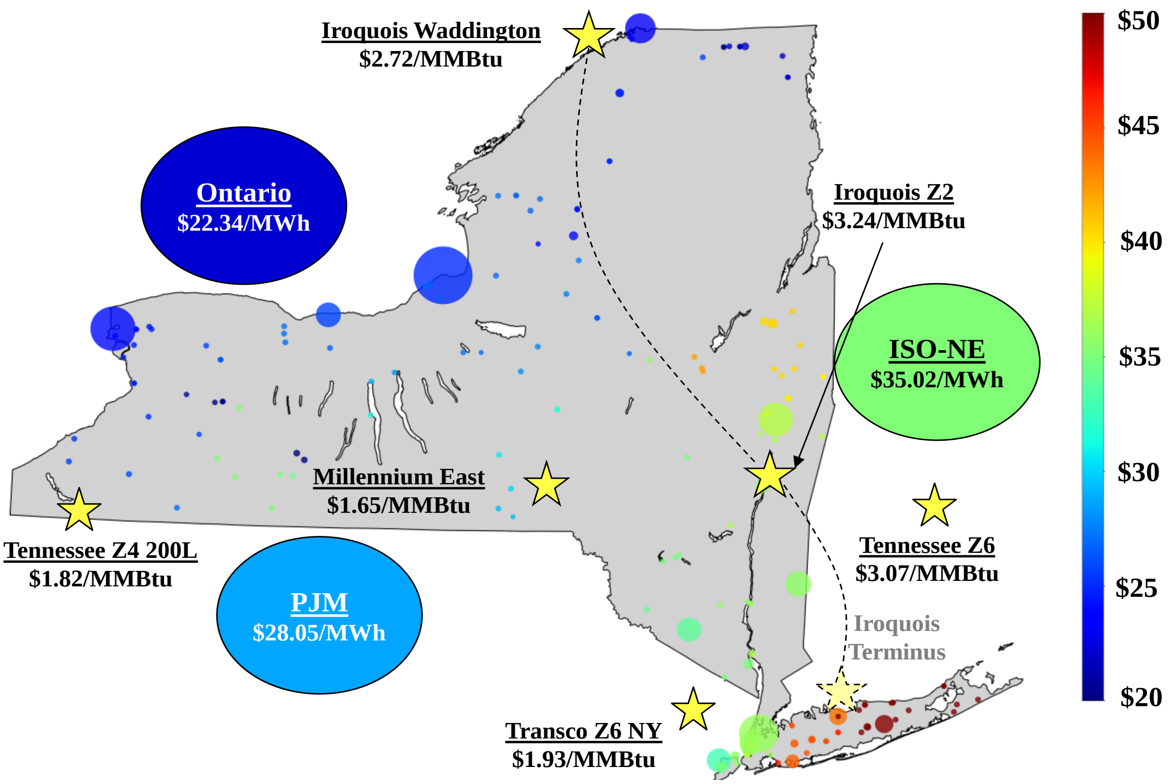
268 Although the differences in LBMPs include the differences in congestion and losses, the differences in losses are usually much smaller than the differences in congestion, particularly between generator nodes that are within smaller subareas.

- 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;[269] and
- Pertinent gas market information including regional gas prices in the systemwide map and key operational points of gas delivery in the NYC map.[270]

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-49: NYCA Real-Time Load-Weighted Generator Congestion Map

2023



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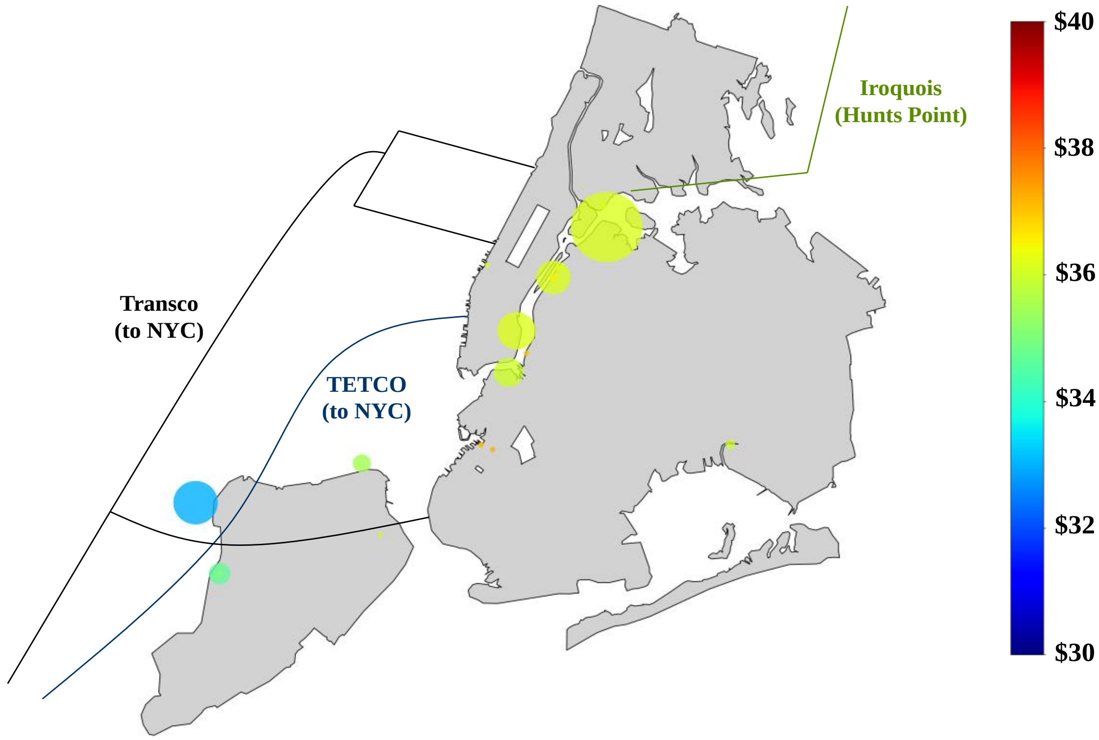
269 The external interface prices are sourced from the respective system operator web platforms for each region. These prices can be found for each region at PJM, ISO-NE, and IESO web platforms.

270 Natural gas prices are based on the average index prices without additional adders sourced from Platts.

Figure A-50: NYC Real-Time Load-Weighted Generator Congestion Map
2023



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.[271]

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-51 & Figure A-52: OOM-Managed Constraints on the Low Voltage Network

Figure A-51 shows the number of days in 2023 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-51: OOM-Managed Constraints in New York
Summary of Resources Used to Manage Constraints, 2023

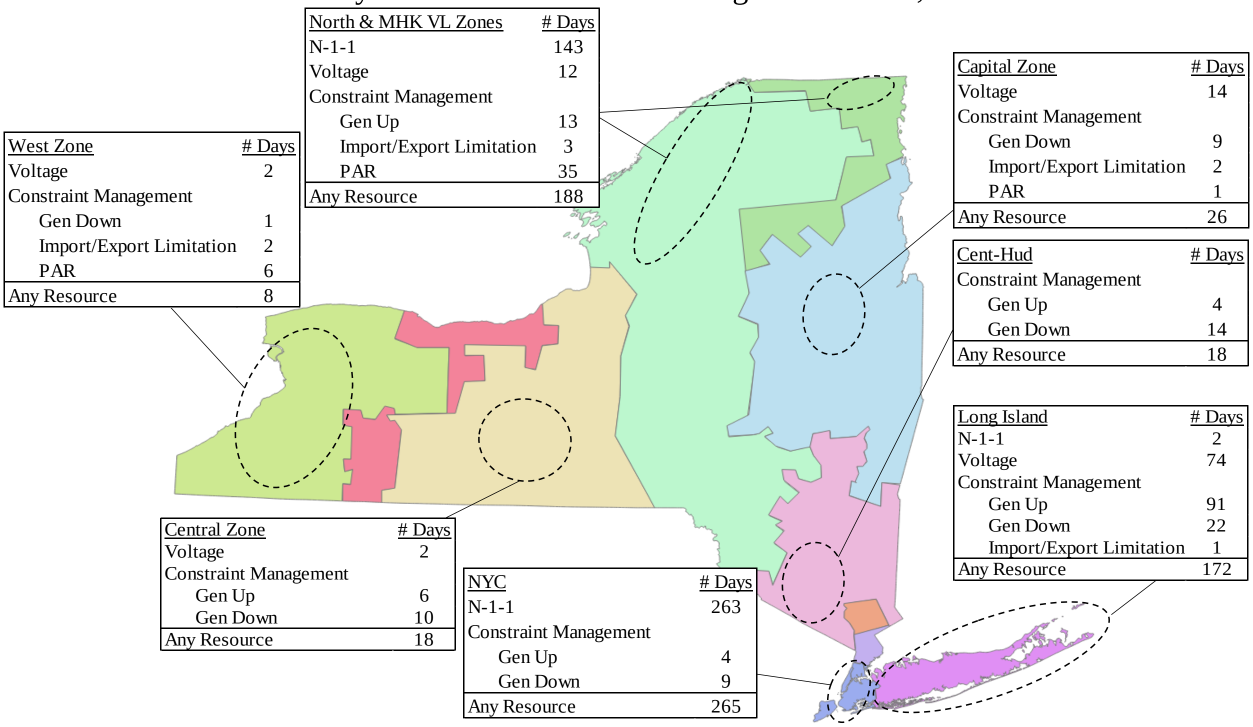


Figure A-52 focuses on the area of Long Island, showing the number of hours and days in 2023 when various resources were used to manage 69 kV (labeled as "69 kV OOM") and TVR constraints (labeled as "TVR OOM") in four load pockets of Long Island:

- Valley Stream: Mostly constraints around the Valley Stream bus;

271 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.

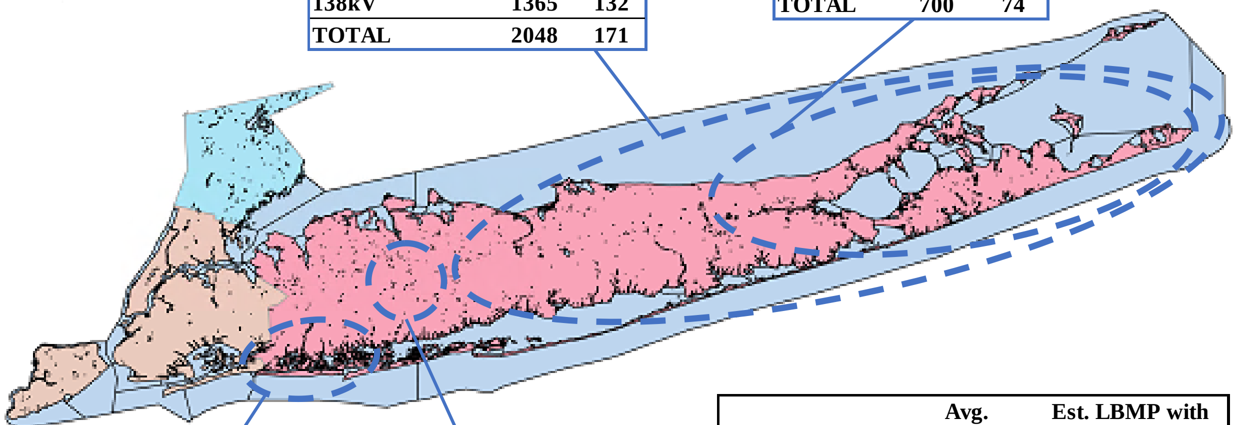
For a comparison, the tables also show the frequency of congestion management on the 69 kV and 138 kV constraints via the market model. Figure A-52 also shows our estimated price impacts in each Long Island load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.[272]

Figure A-52: Constraints on the Low Voltage Network on Long Island

Frequency of Action Used to Manage Constraints, 2023

East of Northport	#Hours	#Days
69kV OOM	114	16
69kV	1851	164
138kV	1365	132
TOTAL	2048	171

East End	#Hours	#Days
69kV OOM	44	8
TVR OOM	676	69
TOTAL	700	74



Valley Stream	#Hours	#Days
69kV OOM	473	41
138kV	1478	177
TOTAL	1888	193

Brentwood	#Hours	#Days
69kV OOM	33	5
69kV	283	70
TOTAL	310	73

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$40.19	$40.25
East End	$44.31	$61.20
East of Northport	$43.52	$44.37
Valley Stream	$38.97	$44.46

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.[273] These required resources are expensive oil peakers, which are not often economically committed. Therefore, OOM commitments are made by the local TO based on operating guidelines.[274] These OOM commitments not only generate uplift but also depress real time prices on Long Island (see Figure A-52). It would be beneficial

272 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.

273 Includes Global Greenport GT, East Hampton units, South Hampton IC, and Southhold IC.

274 See *East End Operating Guideline*, available at: https://www.psegliny.com/oasis/transmission-owner-information-being-released-to-market.

to model the requirements in the market software, which would lead to more efficient scheduling and pricing of resources on Long Island. This subsection describes an approach to model TVR requirements as linear constraints for the scheduling and pricing purpose.

There are three tables in the East End Operating Guideline that tabulate multiple operating options under different outage conditions and load levels. Table A-1 is one of the three tables in the Operating Guideline, which tabulates 10 resource commitment options when the Canal DRSS is out of service and local load arises to different levels.[275] For example, 'Option 1' shows that, for the 'East Hampton Dynamic VAR Compensator In Service' scenario, Global Greenport GT should be first online to satisfy the TVR when local load arises to 115 MW, and then East Hampton GT should be brought online as load increases to 143 MW, and then East Hampton Diesel needs to be committed when load continues to rise to 160 MW, etc.

Table A-1: East End Operating Guideline

Canal DRSS Out of Service

<table>
<tr><th>SF Load (MW) E. HAMP D-VAR I/S</th><th>SF Load (MW) E. HAMP D-VAR O/S</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th><th>Option 5</th><th>Option 6</th><th>Option 7</th><th>Option 8</th><th>Option 9</th><th>Option 10</th></tr>
<tr><td>115</td><td>104</td><td colspan="6">GREENPORT GT</td><td colspan="2">EHAMP GT</td><td colspan="2">SHMP GT</td></tr>
<tr><td>127</td><td>116</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>GRNPRT</td><td>EHMP GT</td></tr>
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<tr><td>143</td><td>132</td><td colspan="2">EHAMP GT</td><td colspan="2">SHLD GT</td><td colspan="2">EHAMP D</td><td></td><td></td><td></td><td></td></tr>
<tr><td>144</td><td>133</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>EHMP D</td></tr>
<tr><td>152</td><td>141</td><td></td><td></td><td></td><td></td><td colspan="2">EHAMP GT</td><td></td><td></td><td></td><td></td></tr>
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<tr><td>156</td><td>145</td><td></td><td></td><td>EHMP D</td><td>EHAMP GT</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td>165</td><td>154</td><td></td><td></td><td>EHAMP GT</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>169</td><td>158</td><td>SHMP GT</td><td>EHMP D</td><td></td><td></td><td>SHLD GT</td><td colspan="3">SHAMP GT</td><td></td><td></td></tr>
<tr><td>173</td><td>162</td><td></td><td></td><td></td><td>EHMP D</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td>194</td><td>183</td><td colspan="10">Arm Under Voltage Load Shedding Scheme</td></tr>
</table>

Although the ten options in the Table A-1 seemingly look unrelated, they do follow certain mathematical relationships between required resource capacity and local load levels.

For illustration purposes, Table A-2 shows a numeric version of Table A-1 by replacing the five oil peakers with their 2022 Summer DMNC values (i.e., replacing Global Greenport GT with 52 MW, East Hampton GT with 18 MW, South Hampton IC with 8 MW, East Hampton Diesel with 6 MW, and Southhold IC with 10 MW). This table shows the following two mathematic relationships:

- The load increments for the two transmission scenarios (i.e., East Hampton D-VAR I/S or O/S) are the same although their starting points are different. The load trigger starts at 115 MW when the D-VAR is in service but at 104 MW when it is out of service. The 11

[275] This table is excerpted directly from the *East End Operating Guideline, released on 07/08/2019*.

MW of difference between the two transmission scenarios is persistent through all load levels. This is important for the derivation of the second mathematic relationship below.

- Each of the five resources satisfies the TVR for a constant range of load, which is in proportion to their DMNC values. For example, when Global Greenport GT is committed, it satisfies the TVR until the load increases by an additional 28 MW. In Option 1 to Option 6, Global Greenport GT is needed when load reaches 115 MW (use D-VAR I/S as an example), and another resource is needed when the load rises to 143 MW (143-125 = 28 MW). In Option 7, Global Greenport GT is needed when load is at 141 MW, and South Hampton IC is needed when load rises to 169 MW, again 169-141 = 28 MW. The same relationship holds for Option 8 (160-132=28MW), Option 9 (155-127=28MW), and Option 10 (181-153=28MW). The similar relationship can be derived for the other four resources as well, which are shown in Table A-3.

Table A-2: East End TVR Commitment Options with Resource DMNC

Canal DRSS Out of Service

SF Load (MW) E. Hamp D-VAR I/S	SF Load (MW) E. Hamp D-VAR O/S	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9	Option 10
115	104	52	52	52	52	52	52	18	18	8	8
127	116									52	18
132	121							6	52		
141	130							52			
143	132	18	18	10	10	6	6				
144	133										6
152	141					18	18				
153	142										52
155	144									6	
156	145			6	18						
160	149	6	8						6		
164	153									18	
165	154			18							
169	158	8	6			10	8	8	8		
173	162				6						
181	170	10	10				10	10	10	10	10
182	171			8	8	8					
194	183	*ARM Under Voltage Load Shedding Scheme*									

Table A-3 uses the same color scheme as in Table A-2. Each color-coded table entry indicates the 'covered range' of load MW for the represented resource, as explained above. The table shows that each color represents one constant load MW range.[276] We summarize these relationships in Table A-4 for each of five resources.

276 The only exception is at the left bottom corner, where blue and yellow represent both 9 and 12.

Table A-3: Relationship of Required TVR Commitments vs Load Levels

Canal DRSS Out of Service

SF Load (MW) E. Hamp D-VAR I/S	SF Load (MW) E. Hamp D-VAR O/S	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9	Option 10
115	104										
127	116									12	12
132	121							17	17		
141	130							9			
143	132	28	28	28	28	28	28				
144	133										17
152	141					9	9				
153	142										9
155	144									28	
156	145			13	13						
160	149	17	17						28		
164	153									9	
165	154			9							
169	158	9	9			17	17	28	9		
173	162				17						
181	170	12	12				12	12	12	17	28
182	171			17	9	13					
194	183	13	13	12	12	12	13	13	13	13	13

Table A-4: Summary of TVR Load Range vs Resource DMNC

	Resource Name	Generator	Summer DMNC MW	TVR Load Range MW	TVR Load Range/DMNC
	Greenport GT	G1	52	28	0.54
	E Hamp GT	G2	18	17	0.94
	S Hamp IC	G3	8	12	1.50
	E Hamp Diesel	G4	6	9	1.50
	Southhold IC	G5	10	13	1.30

Therefore, the following linear constraints could be developed in general for the TVR operating guideline in Table A-1:

- 0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= Load – (115-1) (for D-VAR I/S)
- 0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= Load – (104-1) (for D-VAR O/S)

It is noted that the linear constraints should be written separately for commitment and pricing. Taken the 'D-VAR I/S' scenario as an example,

- For commitment, 0.54*C1 + 0.94*C2 + 1.5*C3 + 1.5*C4 + 1.3*C5 >= Load – 114, where C1-C5 are either 0 or individual UOL.
- For pricing, 0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= Load – 114, where G1-G5 are flexible from 0 to individual UOL.

These linear constraints could be developed similarly for all TVR requirements specified in the *East End Operating Guideline*, which provide a mechanism to efficiently schedule and price the TVR requirement through the market software rather than inefficient OOM actions and uplift payments.[277]

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-53: 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 the NYISO.

The 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. The 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-53 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2022 and 2023. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- West Zone Lines: Transmission lines in the West Zone.
- North to Central: Transmission lines in the North Zone, the Moses-South Interface, EDIC-Marcy 345 line, and Marcy 765-Marcy 345 line.

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277 The latest *East End Operating Guideline* provides "Equivalent Unit Support for South Fork Load to Resolve TVR" for these five resources under different DRSS conditions. These numbers are different from the "TVR Load Range MWs" derived in the tables in this subsection. This is likely due to system changes in recent years, including transmission upgrades and load pattern changes (e.g., increased BTM solar).

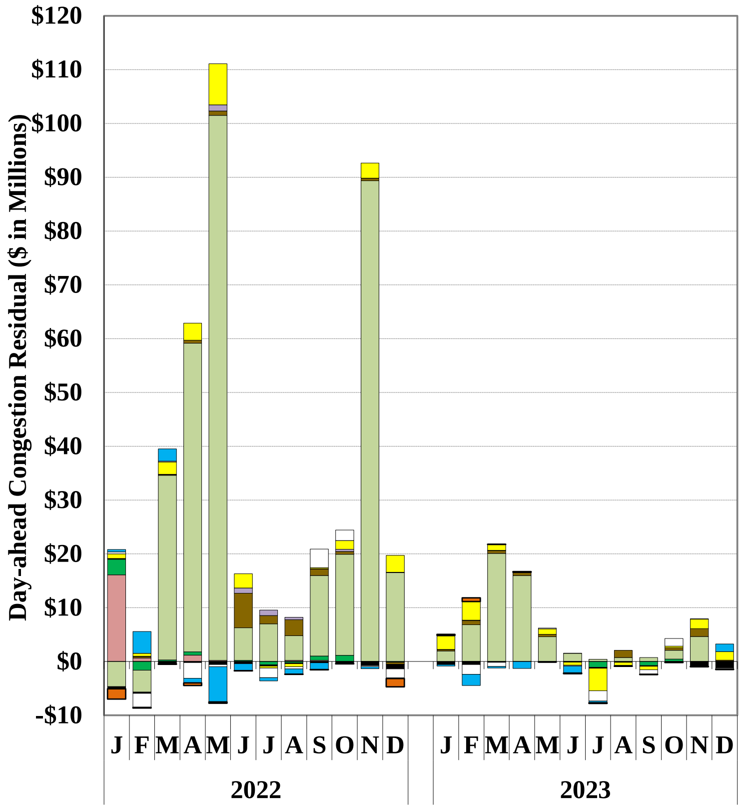
- Central to East: Primarily the Central-East interface.
- Long Island Lines: Lines leading into and within Long Island.
- External: Related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

The figure also shows the shortfalls resulted 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; and
  - Grandfathered TCCs ("GFTCC") that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K), labeled as "Excess GFTCC Allocations" in the figure.

Figure A-53: Day-Ahead Congestion Shortfalls

2022 – 2023



	Category	Annual Shortfall ($M) 2022	Annual Shortfall ($M) 2023
	Central to East	$341.4	$58.9
	North to Central	$14.6	$6.0
	Long Island Lines		
	901/903 PARs	-$4.7	-$3.9
	Excess GFTCC Allocations	$4.3	$0.2
	Other Factors	$23.9	$5.8
	West Zone Lines	$18.5	$0.0
	External	-$5.5	-$4.3
	All Other Facilities	-$4.1	-$4.1

Figure A-54: Balancing Congestion Revenue Shortfalls

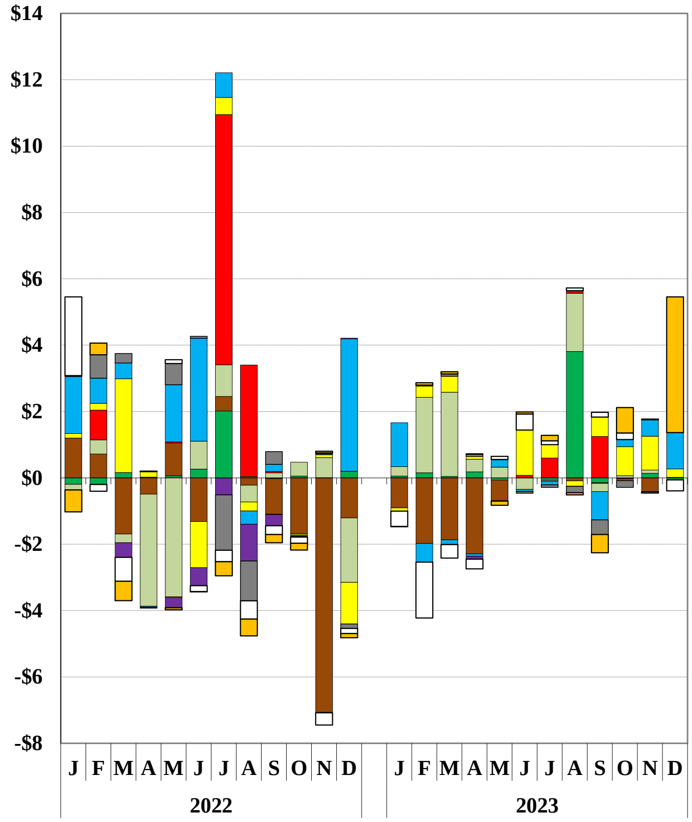
Similar to Figure A-53, Figure A-54 shows balancing congestion shortfalls by transmission path or facility in each month of 2022 and 2023.[278] For select transmission paths, the figure also shows the shortfalls resulted from some unique factors separately from other reasons. Positive values indicate shortfalls, while negative values indicate surpluses.

Like day-ahead congestion shortfalls, balancing congestion revenue shortfalls arise when day-ahead scheduled flows across a particular line or interface exceed its real-time transfer capability. When this occurs, the ISO must 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 balancing congestion shortfall is the cost of this redispatch. The changes in transfer capability between the day-ahead and real-time markets are most often related to:

- Deratings and outages of transmission lines – 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.
- Constraints not modeled 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.

278 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-54: Balancing Congestion Shortfalls
In $Millions, 2022 – 2023



Category	Annual Shortfall ($M) 2022	Annual Shortfall ($M) 2023
Long Island Lines	$1.0	$5.1
N.Y.C.	-$2.4	$4.5
North to Central	$2.4	$4.0
TSA Constraints	$11.9	$2.0
External	$12.3	$1.6
Capital to Hud VL		
Ramapo, A & JK PARs	-$3.3	-$0.1
Other Factors	-$0.9	-$0.8
Central to East		
Ramapo, A & JK PARs	-$11.4	-$8.2
Other Factors	-$6.4	$7.1
All Other Facilities	-$0.5	-$2.1

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.

G. Transmission Line Ratings

Transmission line ratings represent the maximum transfer capability of each transmission line. They are used in the market models to establish commitment and dispatch and affect congestion and prices, therefore it is important to incorporate accurate line ratings. Understated line ratings can lead to inefficient market outcomes (e.g., higher production costs, and unnecessarily high congestion and energy prices), while overstated line ratings may result in potential reliability concerns.

Transmission line ratings are typically based on three types of limits: thermal limits, voltage limits, and stability limits, of which thermal limits are usually the most limiting one for most of transmission lines and interfaces. Thermal limits are typically affected by ambient conditions (e.g., temperature, wind speed, and solar irradiance, etc.). For example, when ambient temperatures are cooler than the typical assumptions used for rating the facilities, additional power flows can be accommodated.

The current NYISO markets use static seasonal line ratings for most facilities in the day-ahead and real-time markets. Although transmission owners provide Ambient Adjusted Ratings ("AAR") to use for some facilities in the real-time market, static line ratings are used for most facilities. This subsection examines the potential economic value of using AARs on an hourly basis in the NYISO day-ahead and real-time markets.

Figure A-55: Potential Congestion Benefit of Using Ambient-Temperature Adjusted Ratings

Figure A-55 shows our estimate of potential congestion benefit from using ambient-temperature adjusted line ratings for 2019 to 2023.

We estimate ambient-adjusted ratings based on the following assumptions: [279]

- 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.[280] 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.[281] 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.

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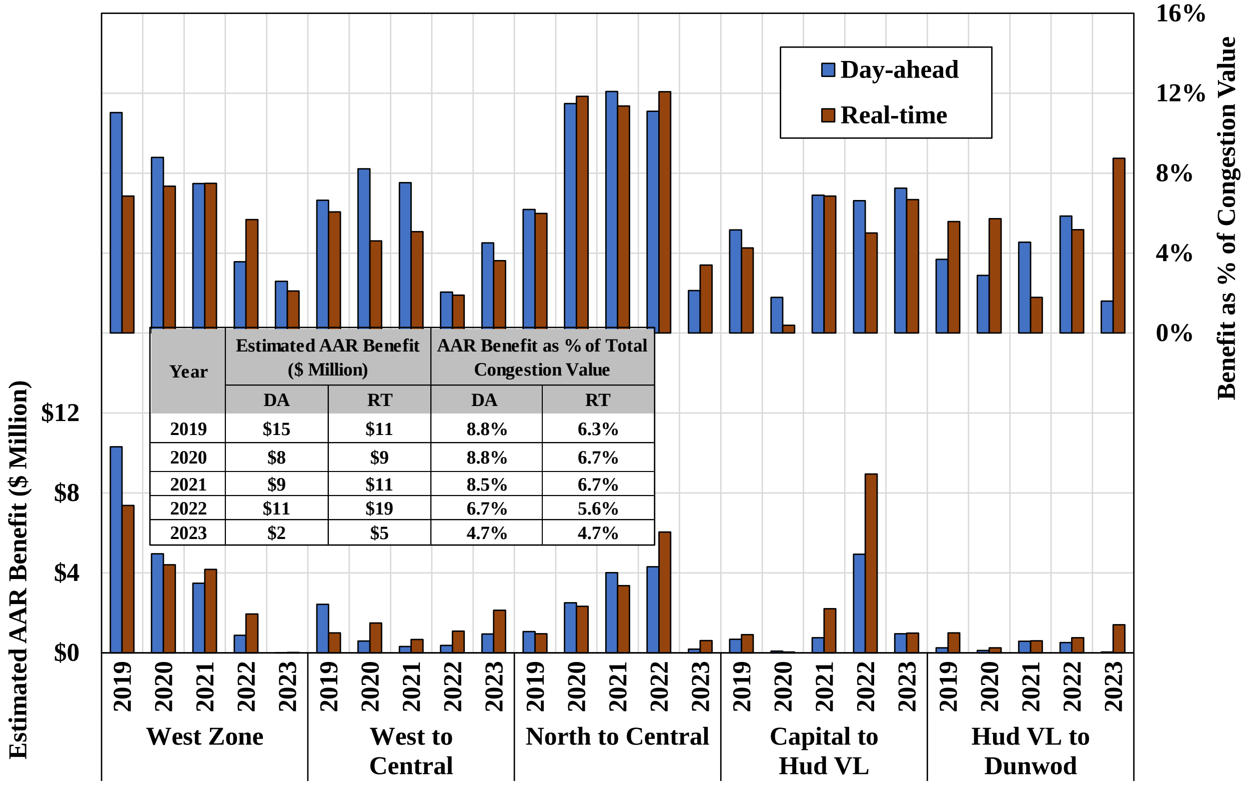
279 See "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" by New York Power Pool, 1995.

280 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.

281 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-55: Potential Congestion Benefit of Using AAR Line Ratings
2019-2023



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%

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* [282] – 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-56: TCC Cost and Profit by Auction Round and Path Type

Figure A-56 summarizes TCC cost and profit for the Winter 2022/23 and Summer 2023 Capability Periods (i.e., the 12-month period from November 2022 through October 2023). 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 2022/23 Capability Period; (c) four rounds of six-month auctions for the Summer 2023 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[283] 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.[284]

282 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.

283 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

284 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-56: TCC Cost and Profit by Auction Round and Path Type

Winter 2022/23 and Summer 2023 Capability Periods

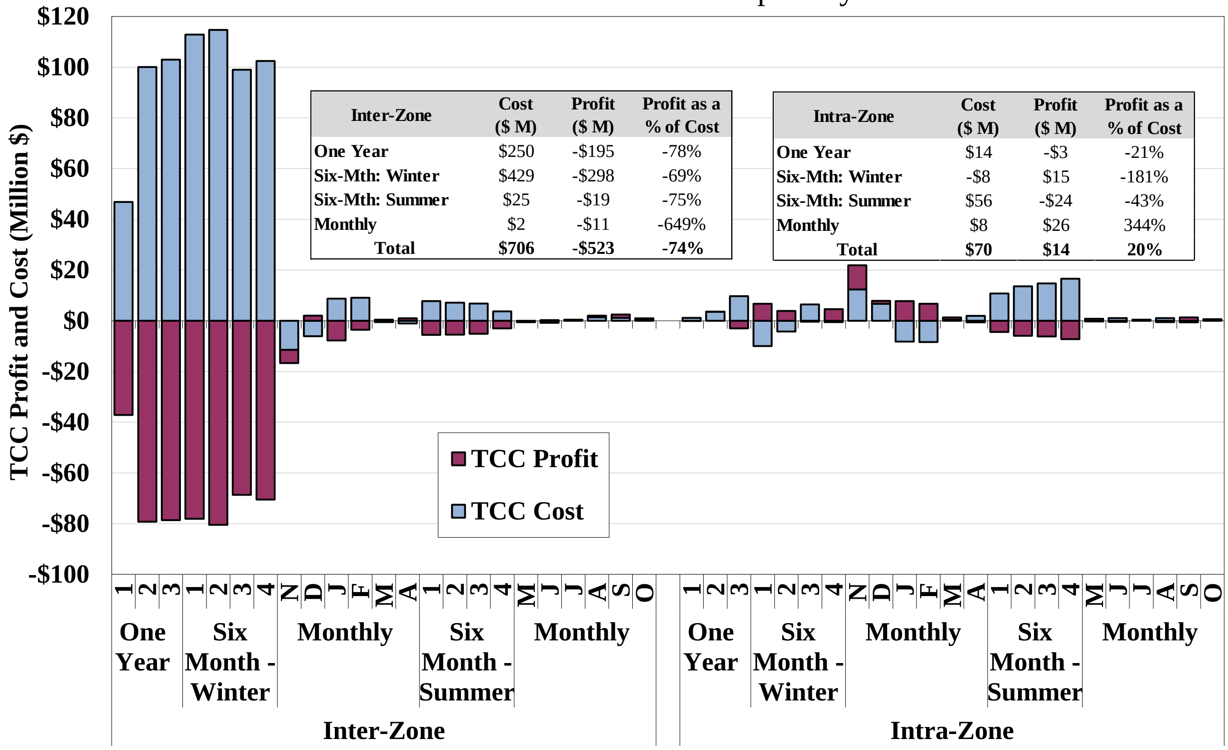


Table A-5 & Table A-6: TCC Cost and Profit by Path

The following two tables compare TCC costs with TCC profits for both intra-zonal paths and inter-zonal paths during the Winter 2022/23 and Summer 2023 Capability Periods (i.e., the 12-month period from November 2022 through October 2023). 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 2022/23 and Summer 2023 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	-$2	-$1	$0	$0	$0	$0	$125	$0	$0	$0	$0	$0	$0	$0	$0	$121
GENESE	$0	$1	$6	$0	$0	-$5	$1	$0	$0	$0	$0	$0	$0	$0	$0	$4
CENTRL	$0	-$3	$39	-$4	$0	$0	$285	-$1	$0	$1	$0	$0	$0	$0	$0	$317
MHK VL	$1	$0	$0	-$76	-$2	-$56	$0	$0	$0	$0	$0	$0	$0	$83	$0	-$50
NORTH	$0	$3	$4	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$69
CAPITL	$0	$0	-$23	-$1	$0	$76	-$73	-$3	-$2	$0	$0	$0	$0	-$1	$0	-$28
HUD VL	-$6	$0	-$18	$0	$0	$58	$1	$5	$4	$18	$0	$0	$0	$97	$0	$158
MILLWD	$0	$0	$0	$0	$0	$0	-$3	$0	$0	$0	$0	$0	$0	$0	$0	-$3
DUNWOD	$0	$0	$0	$0	$0	$0	-$2	$0	$0	$1	$2	$0	$0	$0	$0	$2
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$15	$1	$0	$0	$0	$0	$15
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15	$0	$0	$0	$0	$13
O H	$5	$0	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$7
H Q	$0	$0	$0	$66	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66
NPX	$0	$0	$0	$0	$0	$4	-$2	$0	$0	$0	$0	$0	$0	$0	$0	$1
PJM	-$1	$0	-$15	-$4	$0	$0	$99	$0	$0	$0	$0	$0	$0	$1	$0	$82
Total	**-$3**	**$0**	**-$7**	**$43**	**-$2**	**$76**	**$433**	**$1**	**$1**	**$35**	**$19**	**$0**	**-$1**	**$180**	**$0**	**$775**

Table A-6: TCC Profit by Path
Winter 2022/23 and Summer 2023 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	$1	$1	$2	$0	$0	$0	-$87	$0	$0	$0	$0	$0	$0	$0	$0	-$82
GENESE	$0	-$1	-$4	$0	$0	$3	-$1	$0	$0	$0	$0	$0	$0	$0	$0	-$2
CENTRL	-$6	$2	-$8	$4	$0	$0	-$218	$0	$0	$0	$0	$0	$0	$0	$0	-$226
MHK VL	-$3	$0	$0	$44	$1	$37	-$1	$0	$0	$0	$0	$0	$0	-$63	$0	$17
NORTH	$0	-$2	-$3	-$37	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$40
CAPITL	$0	$0	$13	$1	$0	-$18	$27	$0	$0	$0	$0	$0	$0	$0	$0	$22
HUD VL	$4	$0	$12	$0	$0	-$30	$1	-$4	-$3	-$15	$0	$0	$0	-$69	$0	-$104
MILLWD	$0	$0	$0	$0	$0	$0	$3	$0	$0	$0	$0	$0	$0	$0	$0	$3
DUNWOD	$0	$0	$0	$0	$0	$0	$1	$0	$0	-$1	$3	$0	$0	$0	$0	$3
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	$1	-$7	$0	$0	$0	$0	$0	-$5
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0
O H	-$5	$2	$0	$0	$0	$0	-$2	$0	$0	$0	$0	$0	$0	$0	$0	-$4
H Q	$0	$0	$0	-$40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$40
NPX	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$1
PJM	$0	$0	$13	$3	$0	$0	-$64	$0	$0	$0	$0	$0	$0	-$1	$0	-$50
Total	**-$8**	**$3**	**$26**	**-$25**	**$3**	**-$8**	**-$338**	**-$4**	**-$2**	**-$24**	**$1**	**$0**	**$0**	**-$132**	**$0**	**-$508**

Figure A-57: Oversold TCC vs. DAM Congestion

The analysis below examines the relationship between the oversell (or undersell) of transfer capability in the TCC auction (relative to the transfer capability modeled in the day-ahead market) and levels of day-ahead congestion costs, including congestion residuals and constraint shadow prices. [285] Figure A-57 presents the data related to the Central-East interface during 2023 as follows:

- The x-axis displays the estimated oversell or undersell of transfer capability in the TCC auction in increments of 100 MW. For example, a tranche of 200 MW means that the estimated oversold MW is less than or equal to 200 MW but greater than 100 MW.
- The y-axis shows the following quantities for each tranche:

285 For example, assuming that a constraint is modeled with a transfer limit of 1000 MW in the day-ahead market, an oversell of 200 MW occurs in the TCC auction when 1200 MW of TCC rights are sold along that path, while an undersell of 200 MW occurs when 800 MW of TCCs are sold.

- Average constraint shadow prices during congested hours in the top panel;
- The total number of congested hours in the middle panel; and
- Average congestion residuals accrued in the day-ahead market in the bottom panel. Positive bars indicate shortfalls, while negative bars show surpluses.

Figure A-57: Oversold TCC vs. DAM Congestion

Central-East Interface, 2023

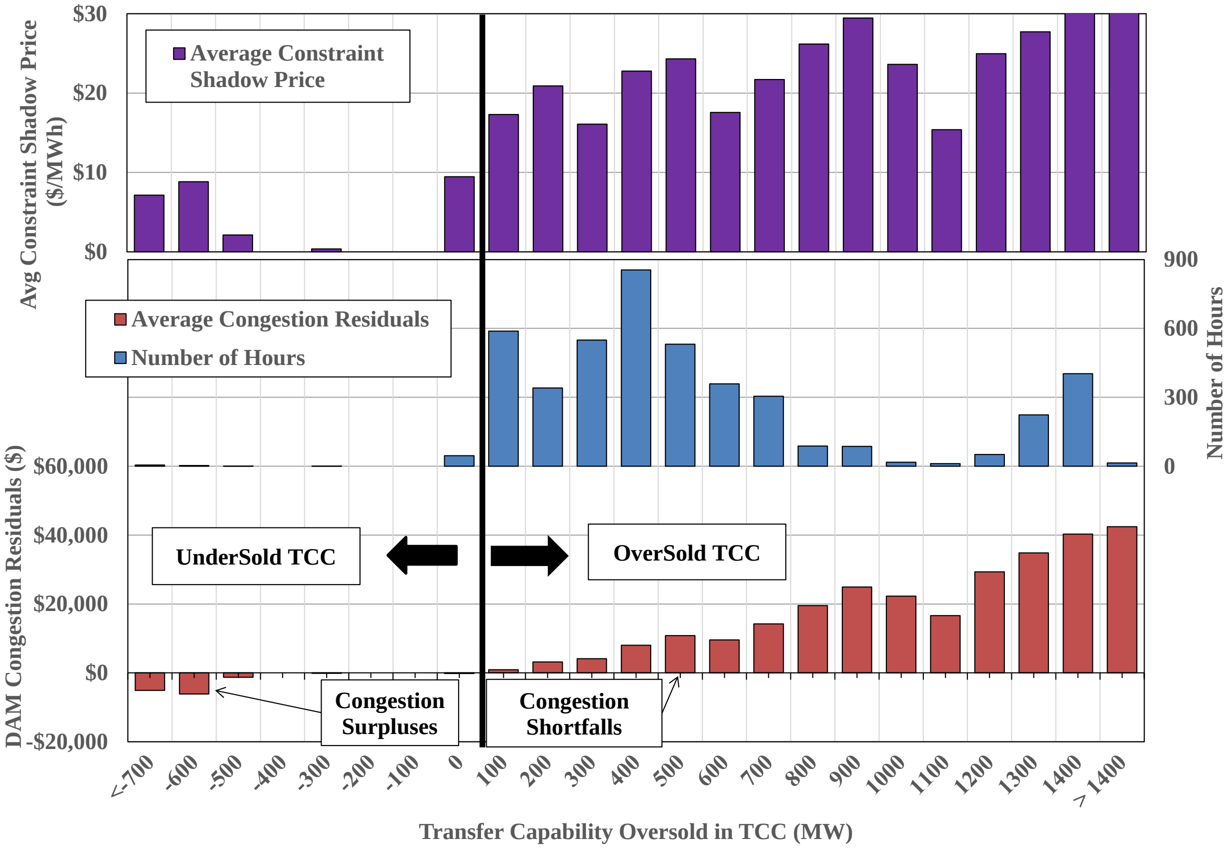


Figure A-58 & Figure A-59: Allocation of Day-ahead Congestion Residuals

The congestion shortfalls and surpluses resulting from differences between the TCC auctions and the day-ahead market are allocated back to transmission owners as charges or credits. As illustrated in Figure A-58, a portion of these shortfalls or surpluses, resulting from changes in transmission transfer capability, attributed to qualifying transmission outages, return-to-service of transmission, facility uprates, and derates, are allocated to the 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. [286]

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

Conversely, the remaining net congestion residuals are allocated to transmission owners in a different way. [287] These allocations are proportional to the auction revenues from each TO's TCC holdings and may not necessarily align with the cost causation principle.

Figure A-58: Illustration of Allocation of DAM Congestion Residuals

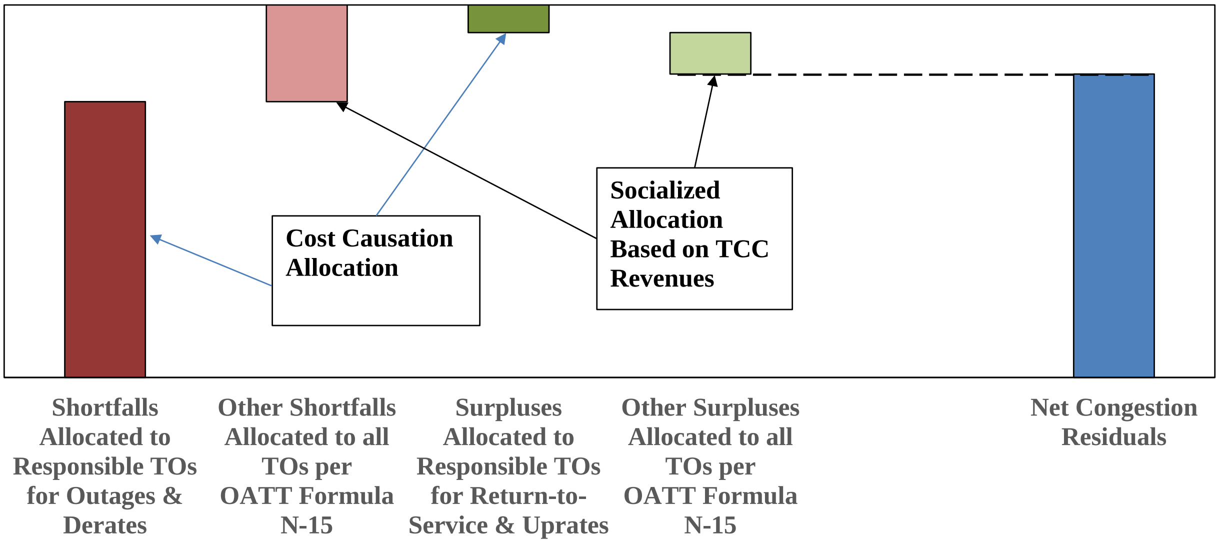
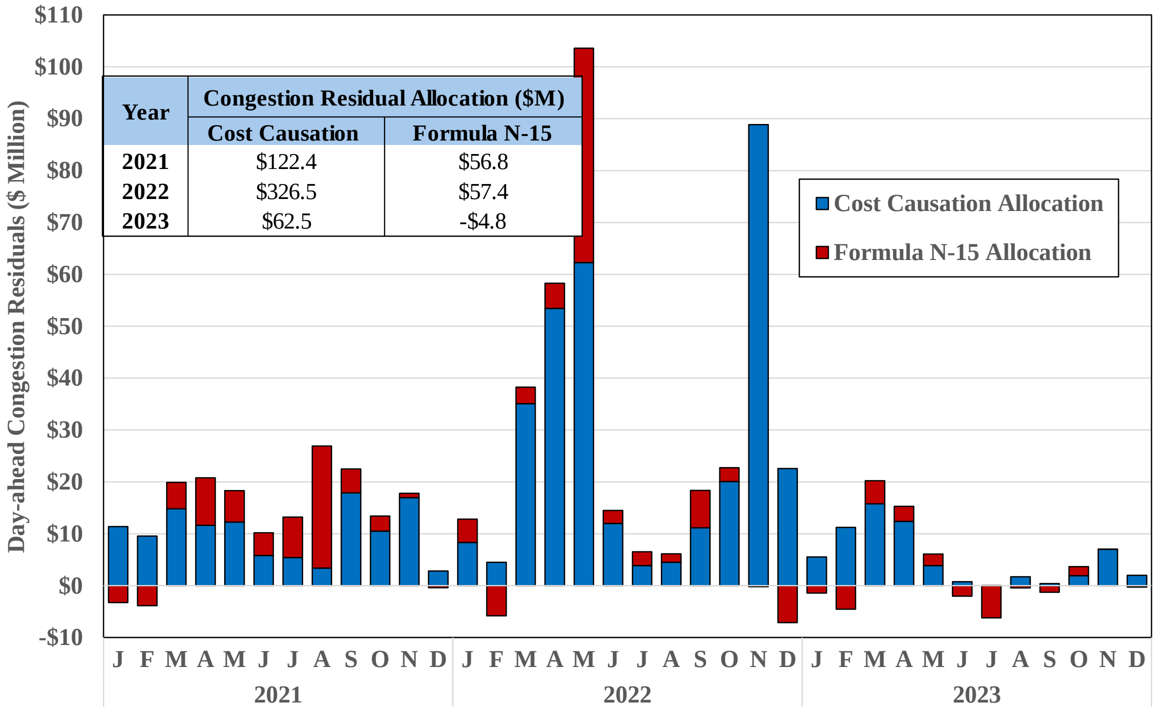


Figure A-59: Allocation of DAM Congestion Residuals
By Month, 2021-2023



Year	Congestion Residual Allocation ($M)	
	Cost Causation	Formula N-15
2021	$122.4	$56.8
2022	$326.5	$57.4
2023	$62.5	-$4.8

287 See OATT, Attachment N, Formula N-15 for the calculation of these allocations.

Figure A-59 shows actual allocations of day-ahead congestion residuals for each month over the past three years. The blue bars represent the portion allocated based on a cost causation principle, while the red bars represent the portion that was allocated based on TCC revenues using Formula N-15 in the OATT Attachment N. The inset table provides a summary of the net amount of congestion residuals allocated through these two methods for each year.

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 XI. 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	Upstate	$25	10000	13000	$250,000	$325,000
Payments	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	Dunwoodie	$5	2000	$10,000
Revenue	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 Payments	Upstate	$25	10000	13000	$250,000	$325,000
	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 Revenue	Dunwoodie	$5	2000	$10,000
	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. In addition to the four primary interfaces with adjacent regions, Long Island and New York City connect directly to PJM and New England across five controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, and the Neptune Cable. The controllable lines are collectively able to import nearly 2.2 GW directly to downstate areas.[288,289] The total transfer capability between New York and the adjacent regions is substantial relative to the total power consumption in New York, making it important to schedule the interfaces efficiently.

Efficient use of transmission interfaces between regions is beneficial in at least two ways. First, the external interfaces allow access to external resources, which helps lower the cost 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. Wholesale markets should facilitate the efficient use of both internal resources and transmission interfaces between control areas.

This section evaluates the following aspects of transaction scheduling between New York and adjacent control areas:

- Subsection A summarizes scheduling patterns 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; and
- 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.

288 The Cross Sound Cable ("CSC") connects Long Island to Connecticut with a transfer capability of 330 MW. The Neptune Cable connects Long Island to New Jersey with a transfer capability of 660 MW. The Northport-to-Norwalk line ("1385 Line") connects Long Island to Connecticut with a transfer capability of 200 MW. The Linden VFT Line connects New York City to PJM with a transfer capability of 315 MW. The Hudson Transmission Project ("HTP Line") connects New York City to New Jersey with a transfer capability of 660 MW.

289 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.

- Subsection E examines several key factors that lead to inconsistencies between RTC and RTD in more details.

A. Summary of Scheduled Imports and Exports

Figure A-60 to Figure A-63 : 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 2022 and 2023. 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-60, the primary interfaces with Quebec and New England in Figure A-61, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-62 and Figure A-63.

Figure A-60: Monthly Average Net Imports from Ontario and PJM

2022 – 2023

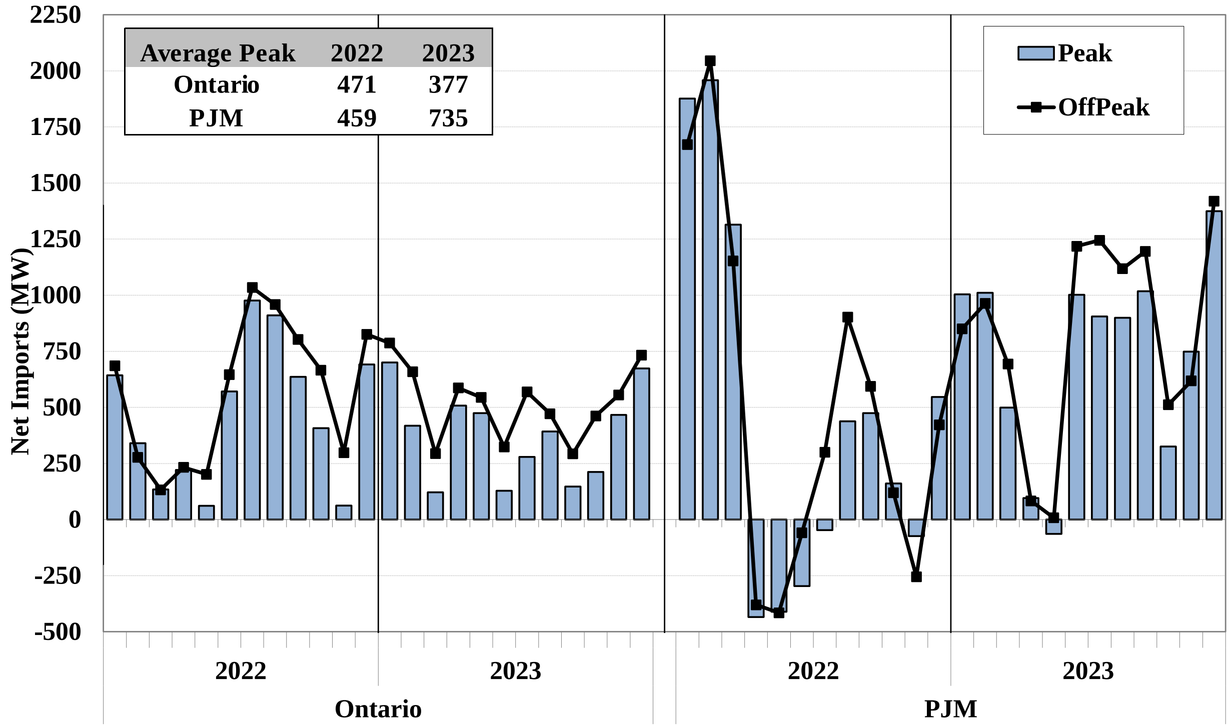
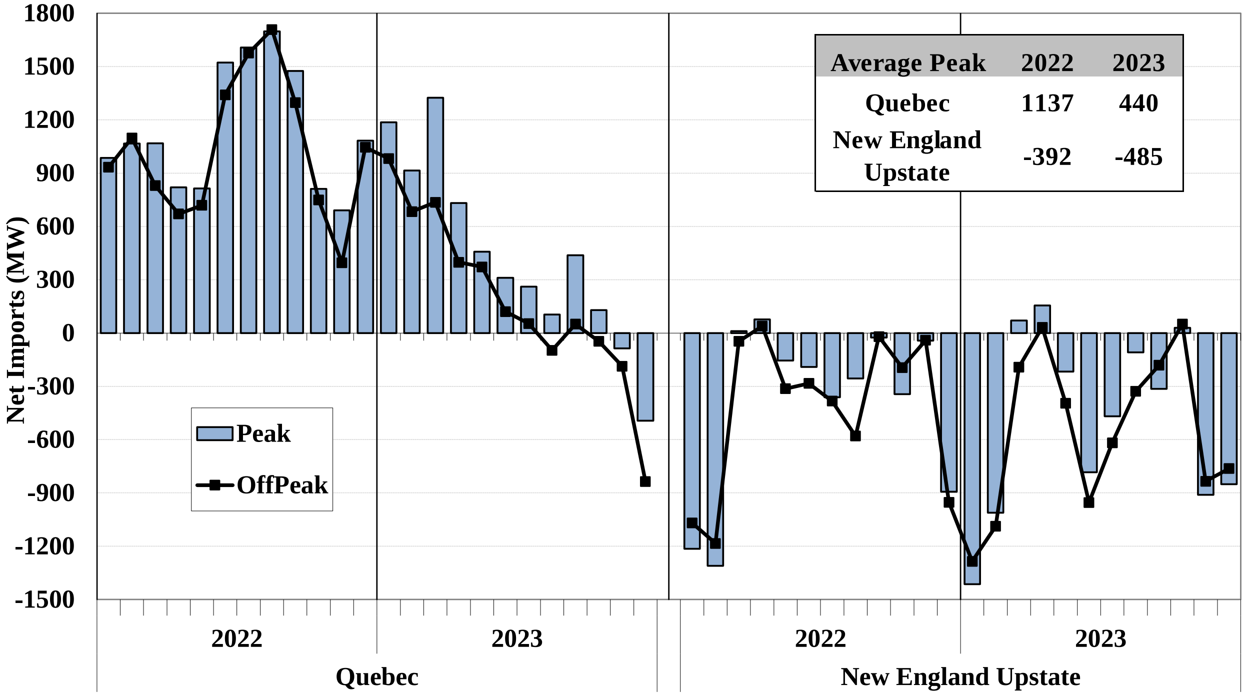
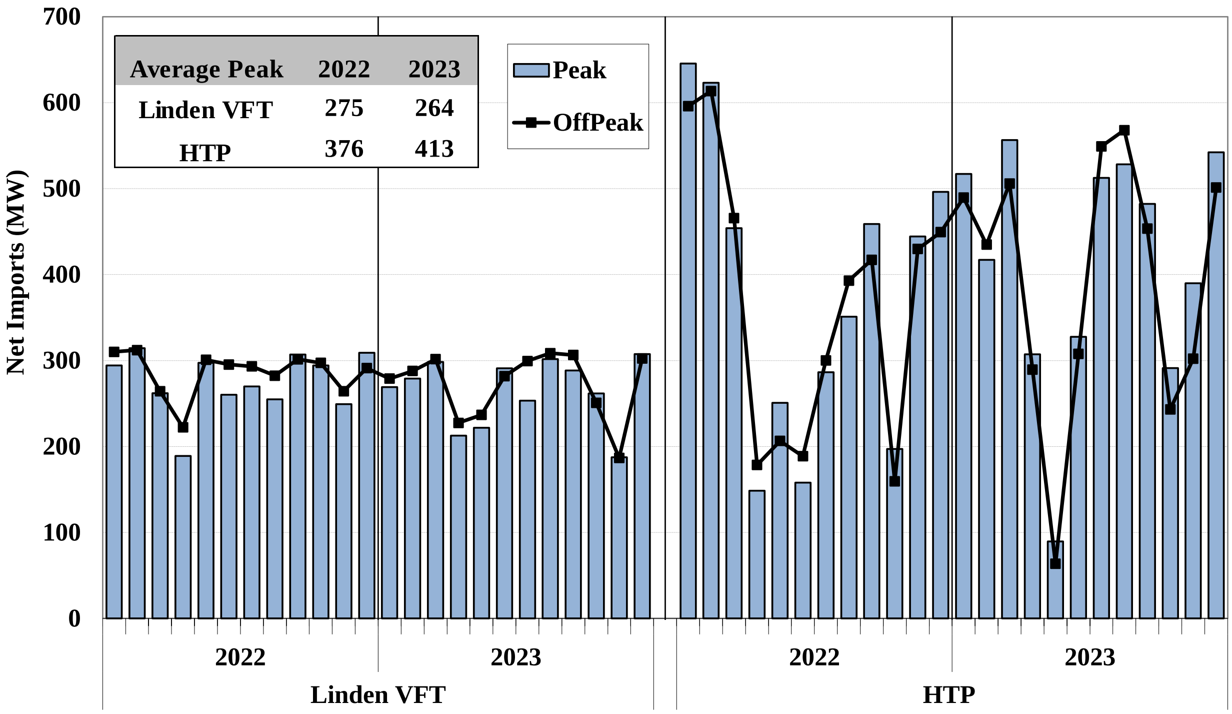


Figure A-61: Monthly Average Net Imports from Quebec and New England
2022 – 2023



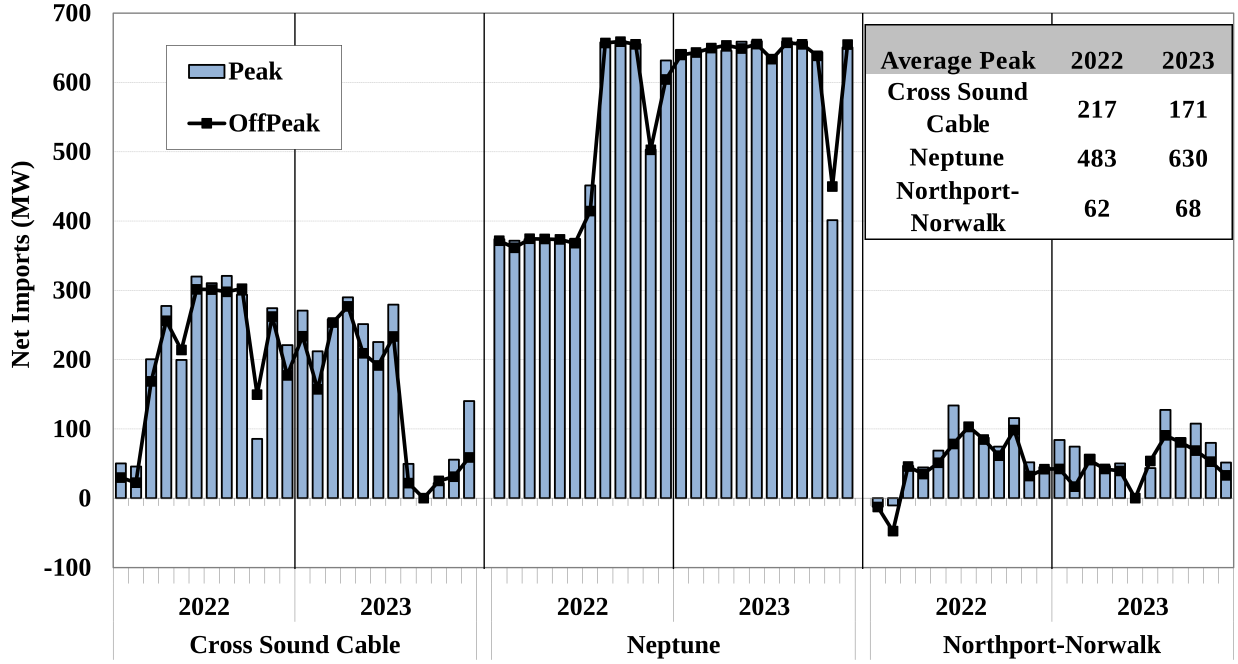
Average Peak	2022	2023
Quebec	1137	440
New England Upstate	-392	-485

Figure A-62: Monthly Average Net Imports into New York City
2022 – 2023



Average Peak	2022	2023
Linden VFT	275	264
HTP	376	413

Figure A-63: Monthly Average Net Imports into Long Island
2022 – 2023



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.

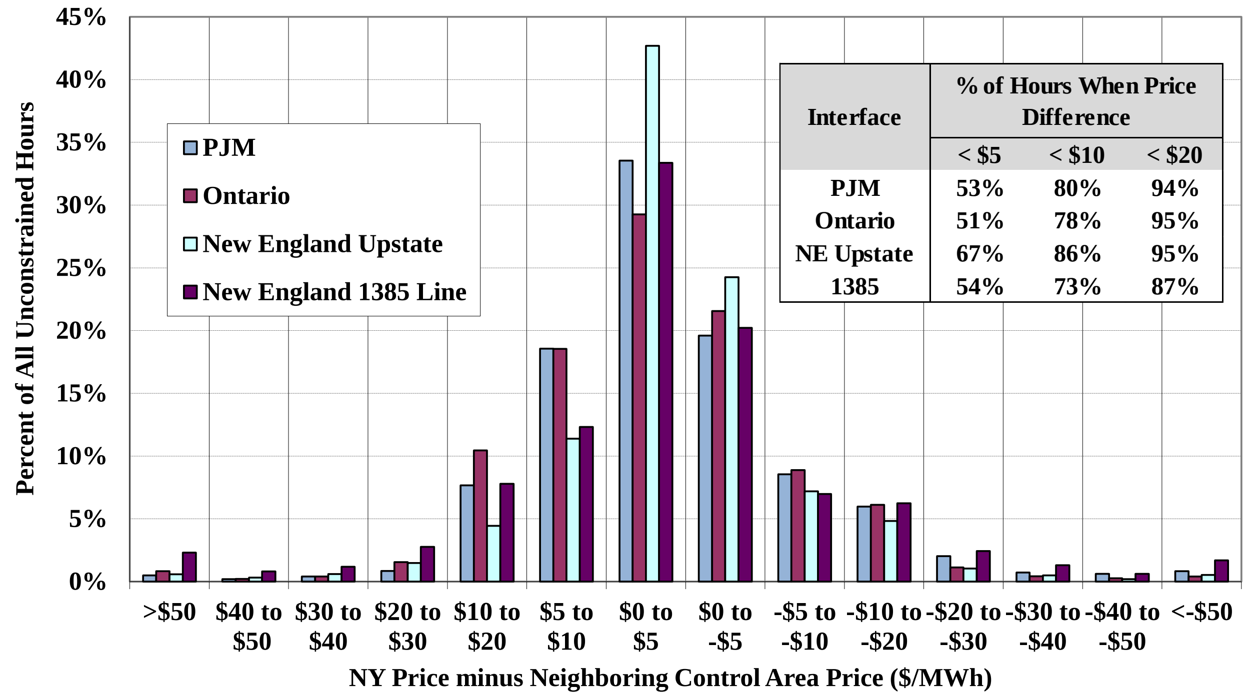
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-64: Price Convergence Between New York and Adjacent Markets

Figure A-64 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-64 summarizes price differences between New York and neighboring markets during unconstrained hours in 2023. 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.[290] 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-64: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2023



290 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 2023. 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.[291]

- 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. [292]

- 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.[293]

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

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291 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 towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

292 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.

293 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.

this will induce other firms to schedule counter-flow transactions, thereby offsetting the effect of 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 – 2023

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Free-flowing Ties								
New England	-584	$0.65	49%	-$3.1	73	$0.91	59%	$3.8
Ontario	388	$3.62	69%	$19.7	65	$3.37	57%	$4.3
PJM	824	$2.20	76%	$27.2	-42	$0.67	58%	$6.4
Controllable Ties								
1385 Line	58	$1.63	71%	$2.6	0	$2.23	55%	$1.1
Cross Sound Cable	156	$7.29	75%	$7.4	-1	$8.01	55%	$0.3
Neptune	637	$11.81	97%	$66.0	-6	$12.60	27%	-$1.5
HTP	370	$7.56	94%	$30.3	33	$7.58	67%	$3.8
Linden VFT	249	$7.77	93%	$18.9	20	$4.68	67%	$2.3

C. Evaluation of Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") allows two wholesale market operators exchange information about their internal prices shortly before real-time, which can be used to assist market participants in scheduling external transactions more efficiently. The CTS intra-hour scheduling system has at least two advantages over hourly LBMP-based scheduling:

- The CTS process schedules transactions much closer to the operating time. Hourly LBMP-based schedules are established up to 105 minutes in advance, while CTS schedules are determined less than 30 minutes ahead when more accurate system information is available.

- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

The CTS was first implemented with PJM on November 4, 2014 and then with ISO-NE on December 15, 2015. It is important to evaluate the performance of CTS on an on-going basis so that the process can be made to work as efficiently as possible.

Figure A-65: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

Figure A-65 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 2023. 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

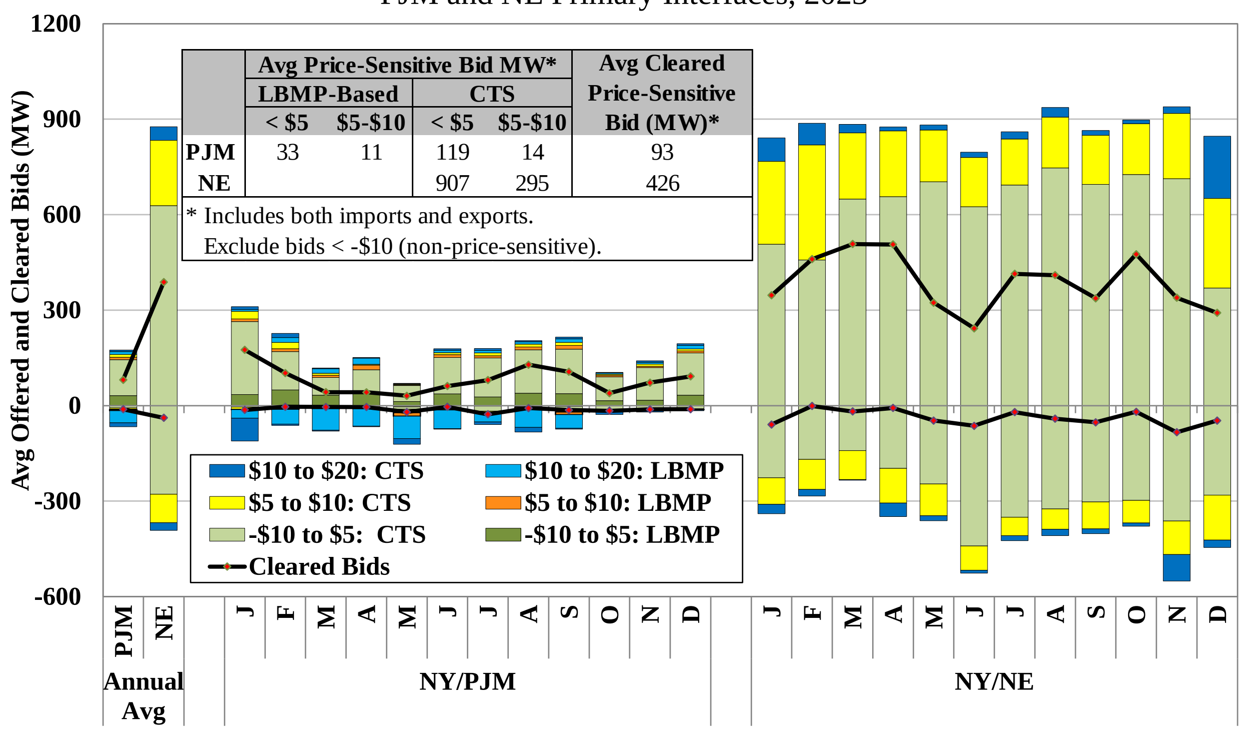
$10/MWh; and (c) between $10 and $20/MWh.[294] Bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis.

Traditional LBMP-based bids and CTS bids are allowed at the PJM interface (unlike the primary New England interface where only CTS bids are allowed). 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 2023.

Figure A-65: Price-Sensitive Real-Time Transaction Bids and Offers by Month
PJM and NE Primary Interfaces, 2023



	Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
	LBMP-Based		CTS		
	< $5	$5-$10	< $5	$5-$10	
PJM	33	11	119	14	93
NE			907	295	426

* Includes both imports and exports.
Exclude bids < -$10 (non-price-sensitive).

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294 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-66: 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-66, the column bars indicate the profitability spread of the middle two quartiles (i.e., 25 to 75 percentile) in 2023. 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 2023 and the inset table summarizes the annual average profit.

Figure A-66: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2023

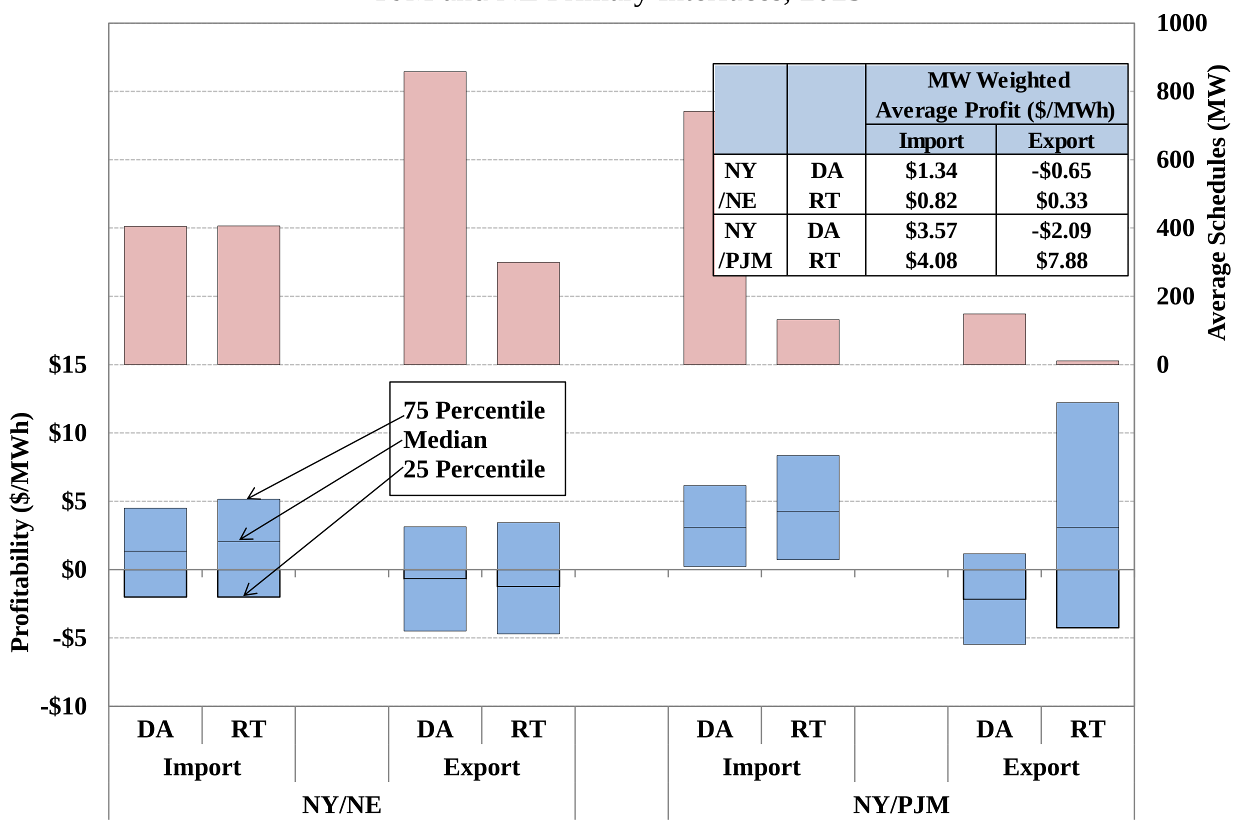

Table A-8: Efficiency of Intra-Hour Scheduling Under CTS

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. [295]

Table A-8 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2023. 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.[296]

    - 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,

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295 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.

296 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 301.

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. [297]

- Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
  - Real-time Curtailment[298] - 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[299] - 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-68). 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[300,301] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

297 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.

298 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).

299 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).

300 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).

301 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

- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.

- 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, 2023

			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total (For Adjustment Intervals Only)	Total (For All Intervals)	Both Forecast Errors <= $20	Any Forecast Error > $20	Total (For Adjustment Intervals Only)	Total (For All Intervals)
% of All Intervals w/ Adjustment			78%	9%	**87%**		40%	9%	**49%**	
Average Flow Adjustment (MW)	Net Imports		6	6	**6**		-10	-69	**-21**	
Average Flow Adjustment (MW)	Gross		116	145	**119**		74	110	**81**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$5.7	$3.6	**$9.3**		$1.3	$5.2	**$6.5**	
Production Cost Savings ($ Million)	Net Over-Projection by:	NY	-$0.3	-$1.1	**-$1.3**		-$0.1	-$0.4	**-$0.5**	
Production Cost Savings ($ Million)	Net Over-Projection by:	NE or PJM	$0.0	-$0.4	**-$0.4**		-$0.6	-$4.9	**-$5.5**	
Production Cost Savings ($ Million)	Other Unrealized Savings		-$0.3	-$0.7	**-$1.0**		$0.0	-$0.5	**-$0.5**	
Production Cost Savings ($ Million)	Actual Savings		$5.1	$1.5	**$6.6**		$0.6	-$0.6	**$0.0**	
Interface Prices ($/MWh)	NY	Actual	$27.97	$70.96	**$32.40**	**$32.77**	$26.20	$42.09	**$29.22**	**$27.91**
Interface Prices ($/MWh)	NY	Forecast	$28.78	$61.46	**$32.15**	**$32.50**	$26.72	$42.05	**$29.64**	**$28.16**
Interface Prices ($/MWh)	NE or PJM	Actual	$27.41	$69.89	**$31.79**	**$34.56**	$24.37	$46.16	**$28.52**	**$26.64**
Interface Prices ($/MWh)	NE or PJM	Forecast	$26.44	$56.77	**$29.56**	**$32.27**	$26.56	$87.55	**$38.17**	**$34.19**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.81	-$9.50	**-$0.25**	**-$0.27**	$0.51	-$0.04	**$0.41**	**$0.25**
Price Forecast Errors ($/MWh)	NY	Abs. Val.	$2.36	$38.55	**$6.09**	**$6.03**	$2.17	$19.27	**$5.42**	**$4.60**
Price Forecast Errors ($/MWh)	NE or PJM	Fcst. - Act.	-$0.98	-$13.12	**-$2.23**	**-$2.29**	$2.19	$41.39	**$9.65**	**$7.55**
Price Forecast Errors ($/MWh)	NE or PJM	Abs. Val.	$3.47	$33.73	**$6.59**	**$6.96**	$4.81	$64.45	**$16.16**	**$13.35**

Figure A-67 & Figure A-68: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-67 shows the cumulative distribution of forecasting errors in 2023. 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.

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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.

Figure A-67: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2023

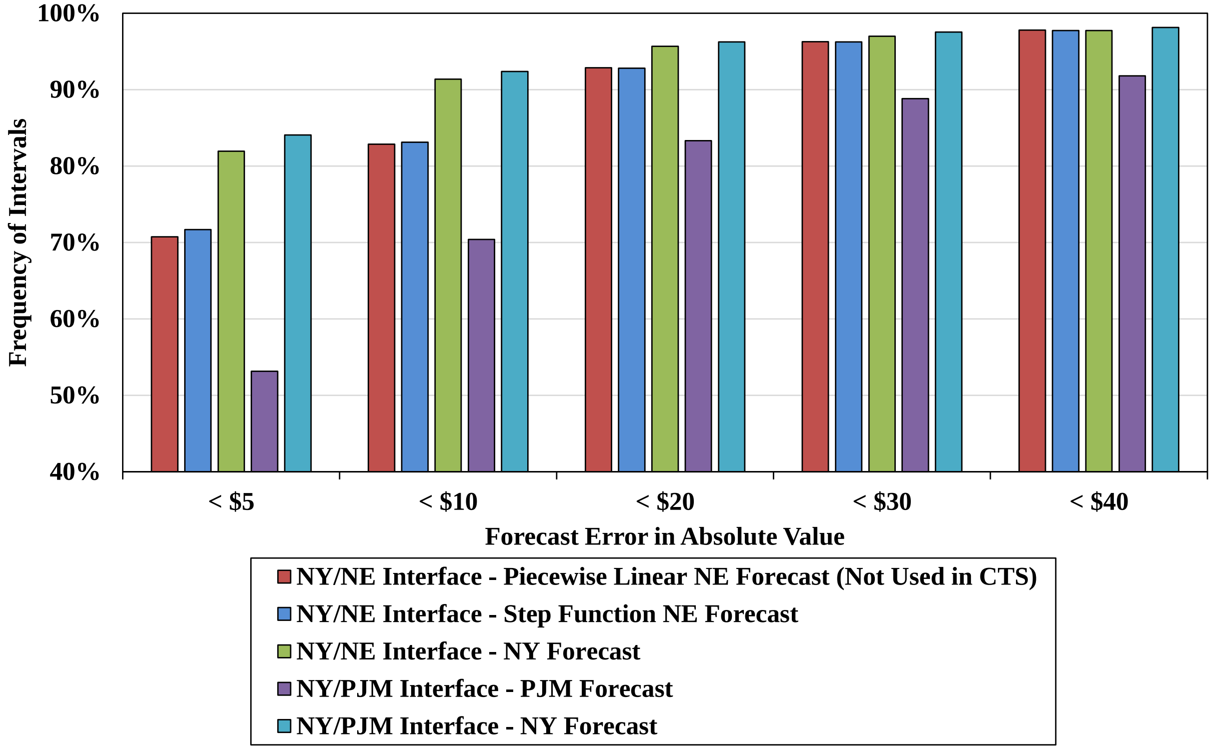

Figure A-68: Example of Supply Curve Produced by ISO-NE and Used by RTC

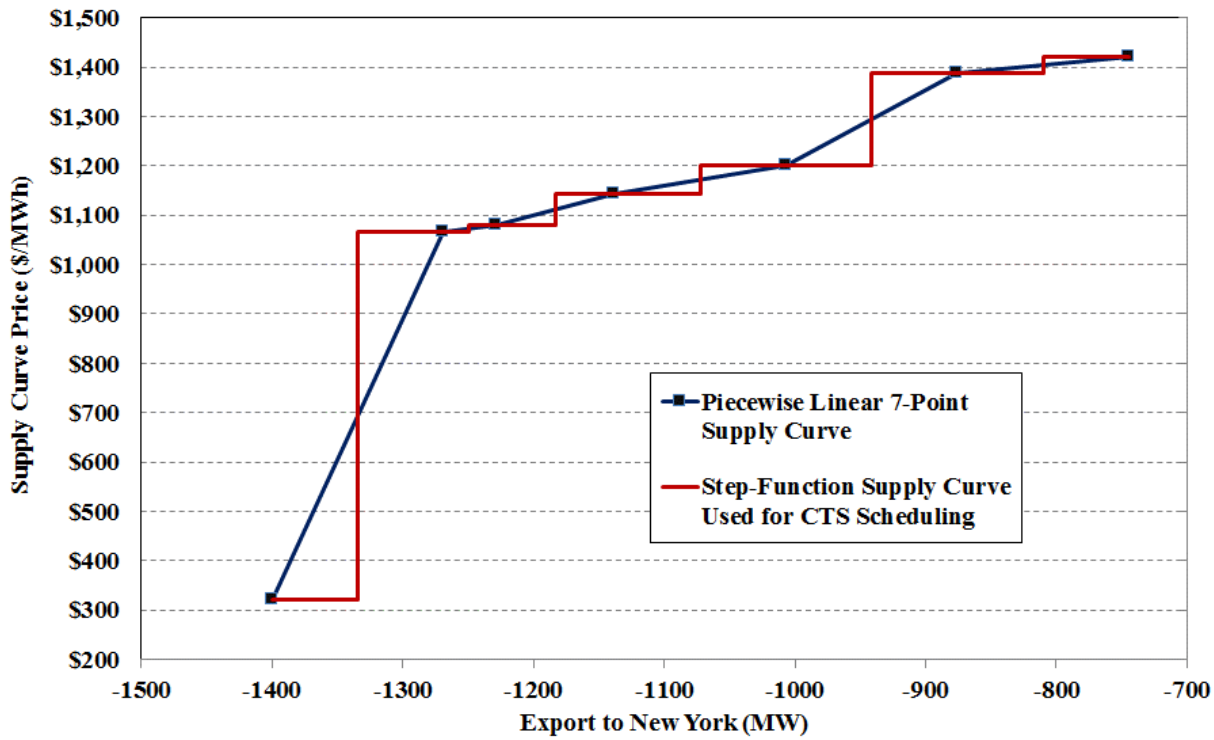

Figure A-67 shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.

Figure A-68 illustrates this with example curves.[302] 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 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.

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-69 to Figure A-71: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-69 to Figure A-71 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation 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).[303]

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-

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302 The two curves are forecasted supply curves used in the market on January 5, 2016.

303 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.

differential between RTC and RTD with the corresponding price-differential for resources that are explicitly considered and priced by the real-time models.

For generation resource, external transaction, or load i, our inconsistency metric is calculated as follows:

$$Metric_i = (NetInjectionMW_{i,RTC} – NetInjectionMW_{i,RTD}) * (Price_{i,RTC} – Price_{i,RTD})$$ [304]

Hence, for the load forecast in the example above, the metric is:

$$Metric_{load} = 100 \text{ MW} * (\$45/MWh – \$65/MWh) = -\$2,000/hour$$

For the high-cost generator in the example above, the metric is:

$$Metric_{generator} = -100 \text{ MW} * (\$45/MWh – \$65/MWh) = +\$2,000/hour$$

For the foregone CTS imports in the example above, the metric is:

$$Metric_{import} = 0 \text{ MW} * (\$45/MWh – \$65/MWh) = \$0/hour$$

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

[304] Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

divergence between RTC and RTD congestion prices). This calculation is performed for both "optimized" PARs and "non-optimized" PARs.[305]

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:

$$\text{Metric\_BindingTx}_c = \text{ShadowPrice}_{c,RTC} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTC} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$
$$- \text{ShadowPrice}_{c,RTD} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTD} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$

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.

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305 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.

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-74.

Figure A-69 summarizes the RTC/RTD divergence metric results for detrimental factors in 2022, while Figure A-70 provides the summary for beneficial factors. Figure A-71 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-69: Detrimental Factors Causing Divergence between RTC and RTD
2023

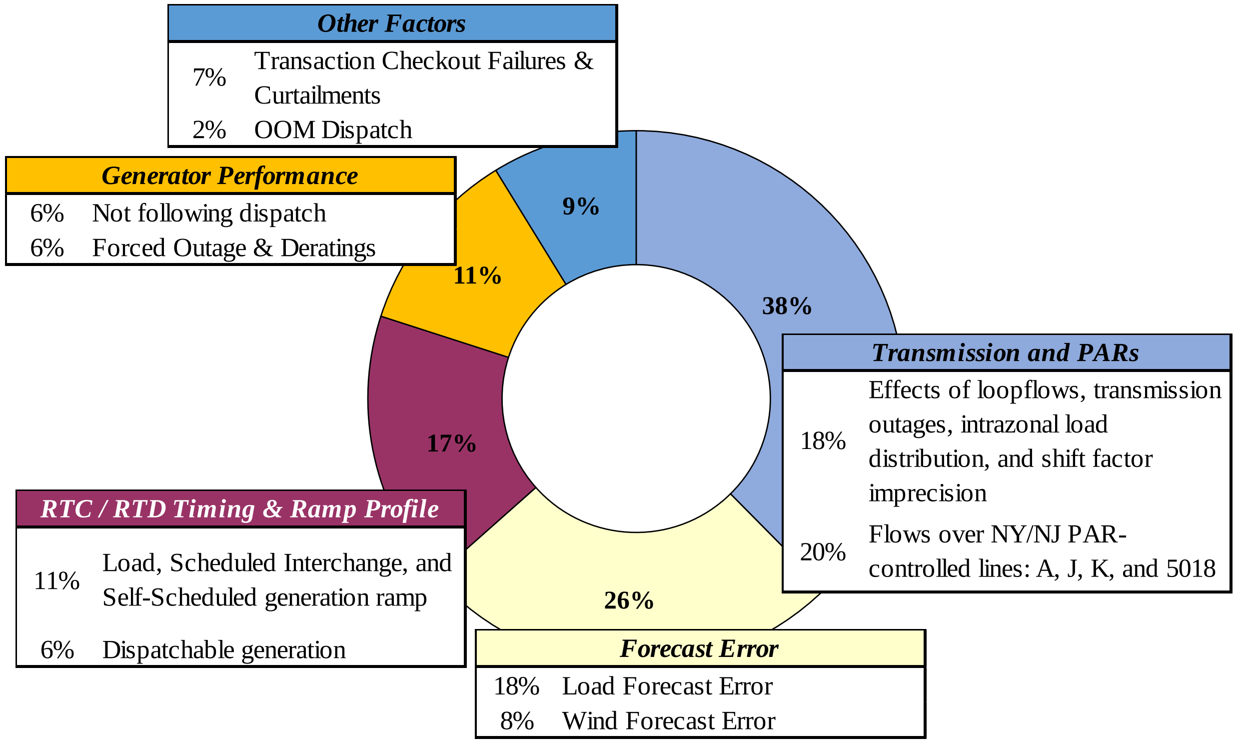


Figure A-70: Beneficial Factors Reducing Divergence between RTC and RTD
2023

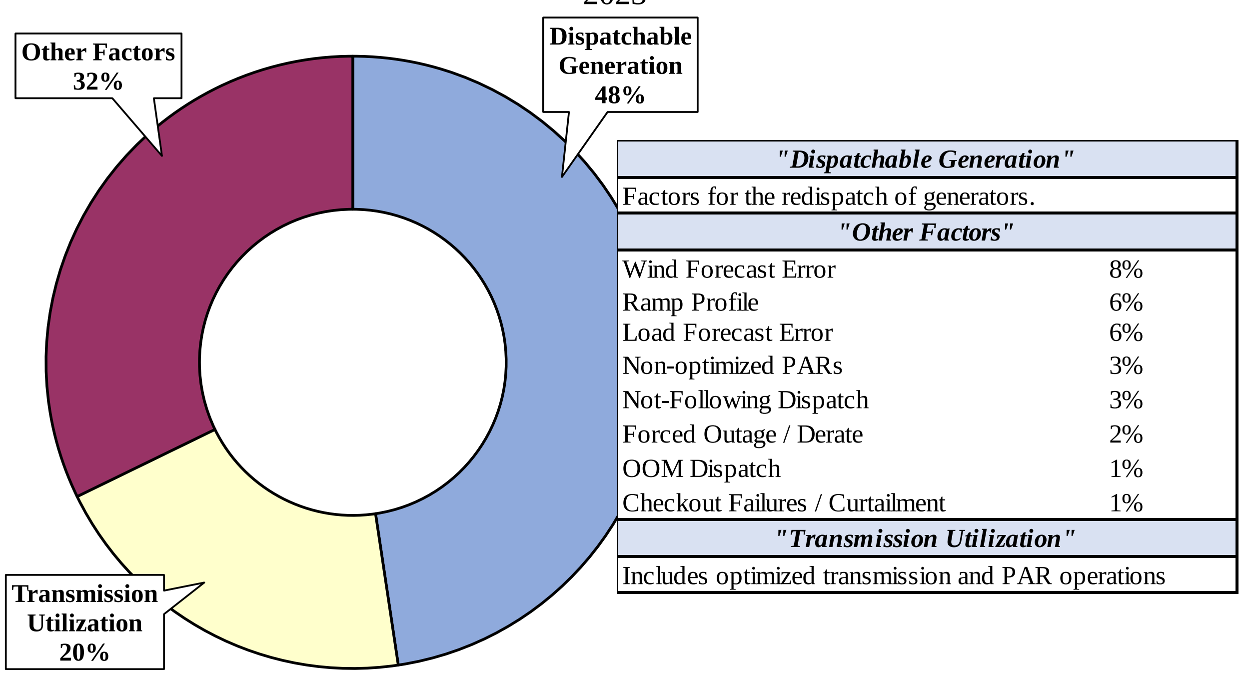
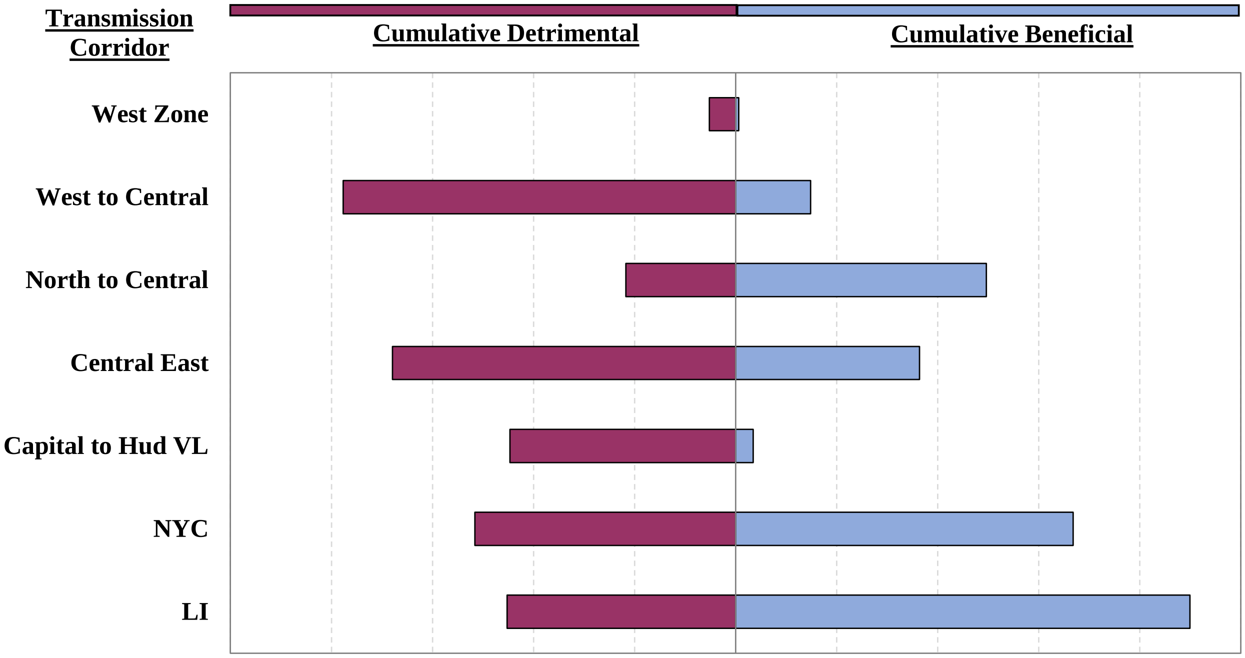


Figure A-71: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2023



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-72 & Figure A-73: Differences in Prices vs Differences in Assumptions of Net Interchanges between RTC and RTD

Figure A-72 shows a histogram of the differences in 2023 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-73 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-72: Histogram of Differences Between RTC and RTD Prices and Net Interchange
2023

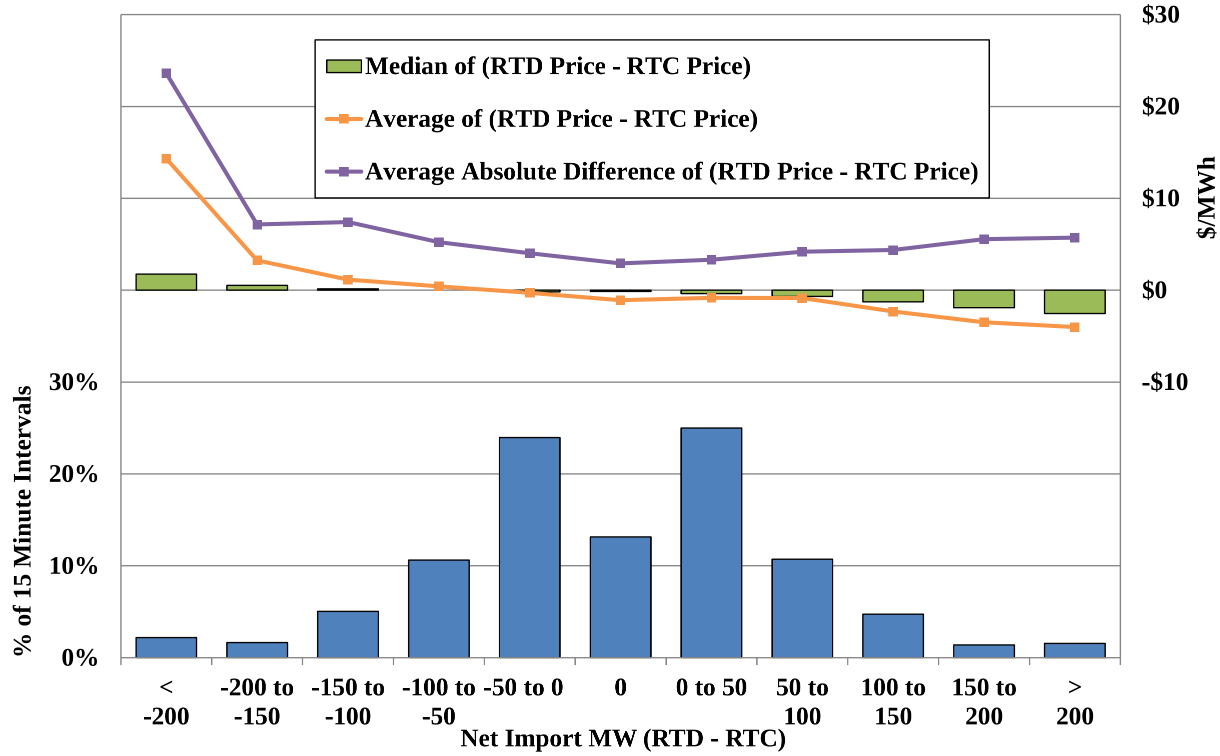


Figure A-73: Differences Between RTC and RTD Prices and Net Interchange Schedules
by Time of Day, 2023

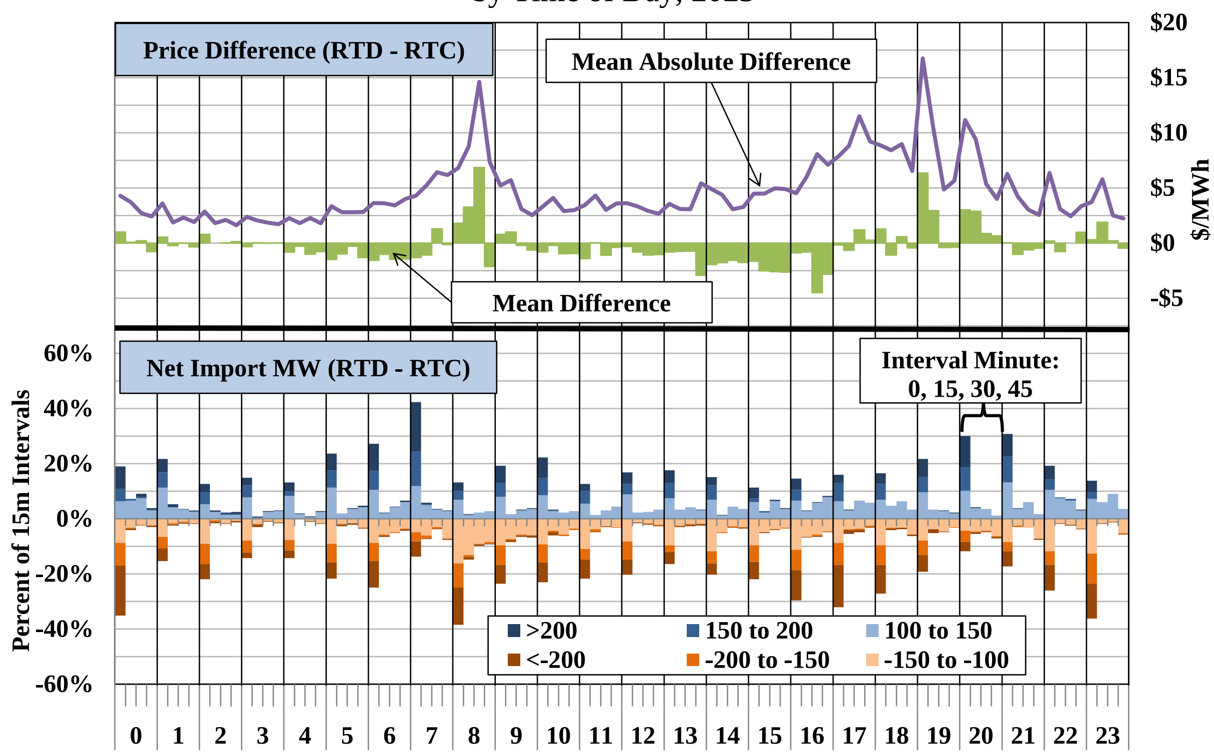


Figure A-74: Illustration of the ramp profiles that are assumed by RTC and RTD

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-74 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-74: Illustration of External Transaction Ramp Profiles in RTC and RTD

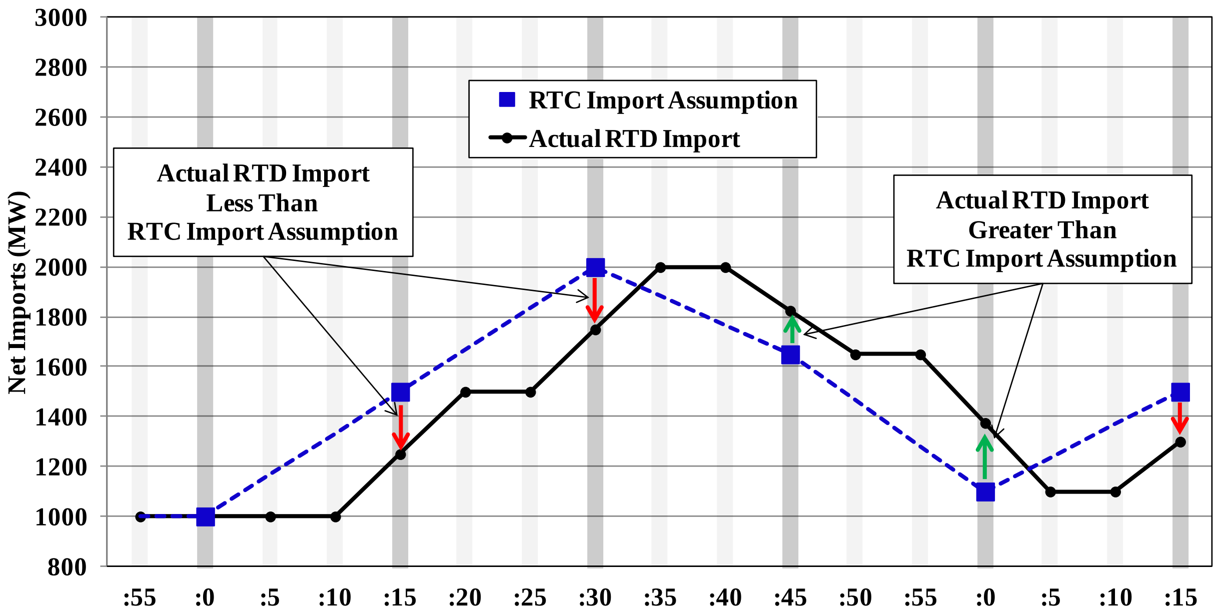


Figure A-75 & Figure A-76: Differences in Prices vs Differences in Load Forecasts between RTC and RTD

Figure A-75 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 2023. 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-76 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-75: Histogram of Differences Between RTC and RTD Prices and Load Forecasts
2023

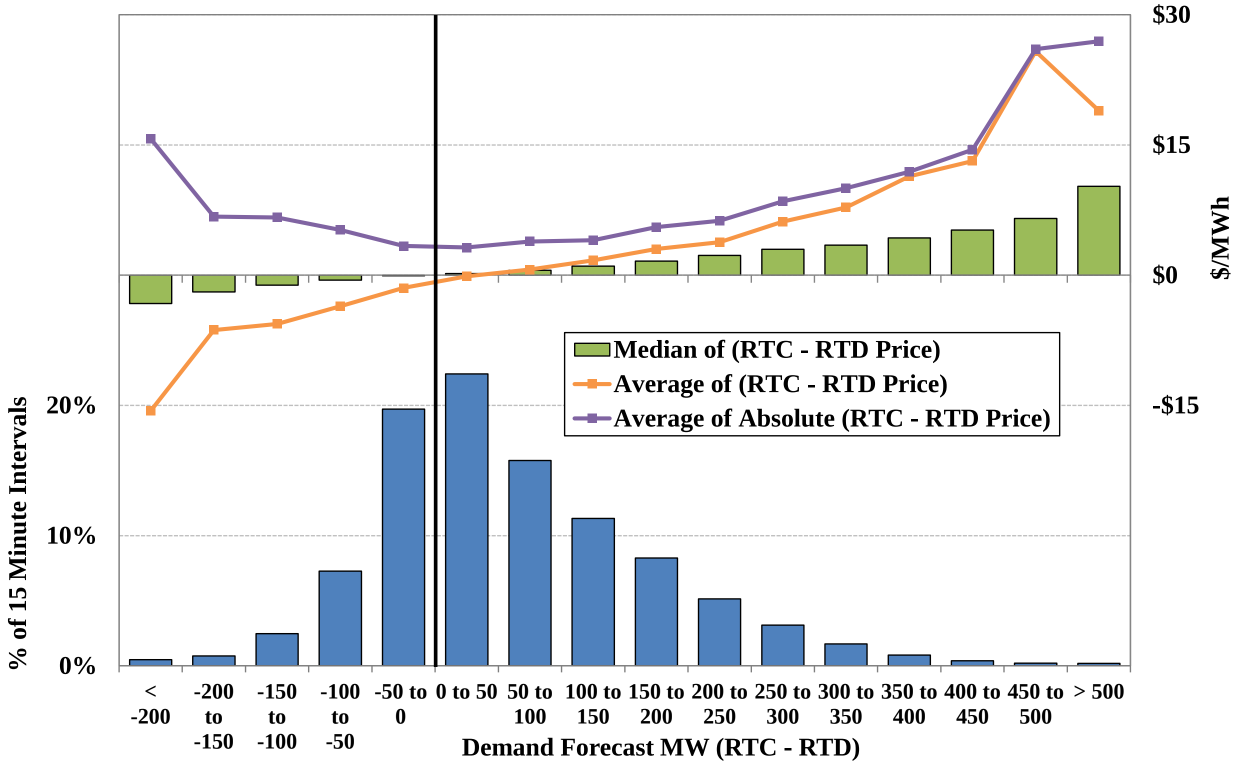


Figure A-76: Differences Between RTC and RTD Prices and Load Forecasts
by Time of Day, 2023

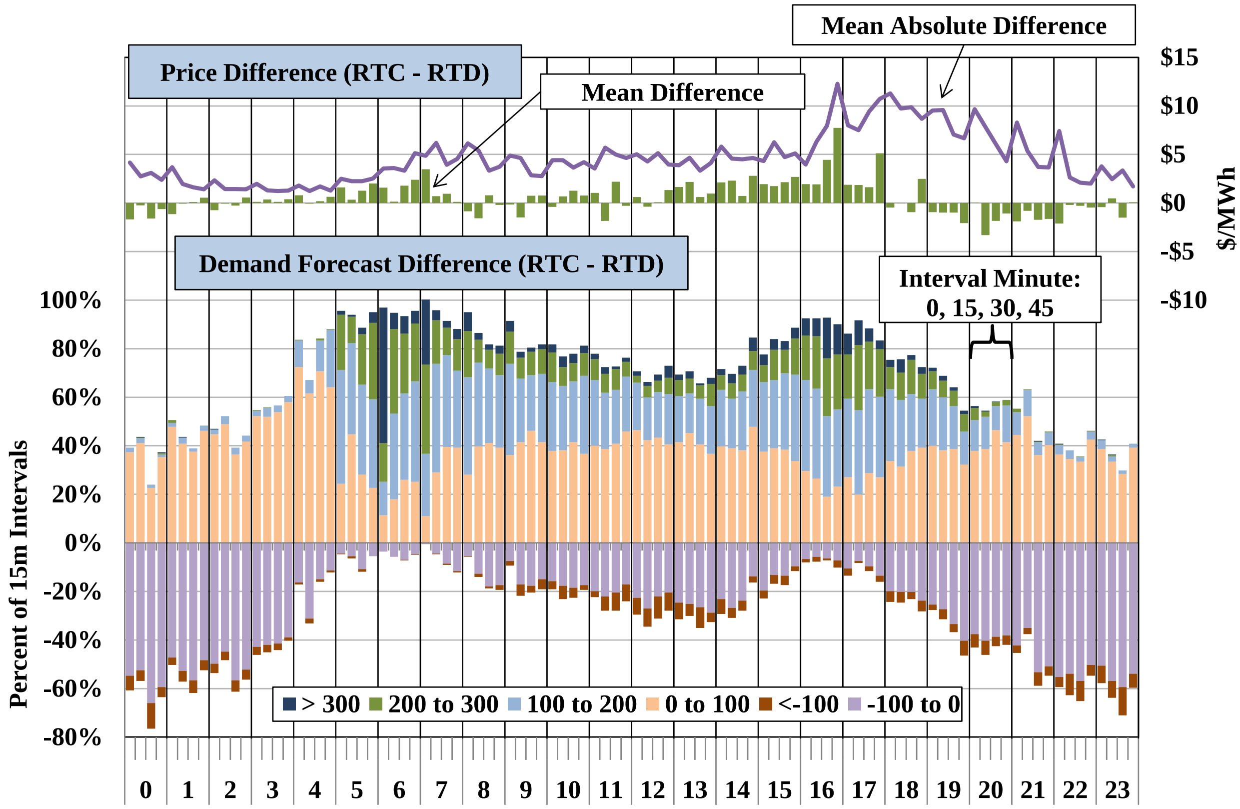


Figure A-77 & Figure A-78: Curtailments on RTC/RTD Divergence

Figure A-77 compares the frequency of external transaction curtailments by month in 2022 and 2023. 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-78 shows the 10 days in 2023 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 (80 percent) is contained within the top 10 days.

Figure A-77: Number of Hours with External Transaction Curtailments by Interface
By Month, 2022-2023

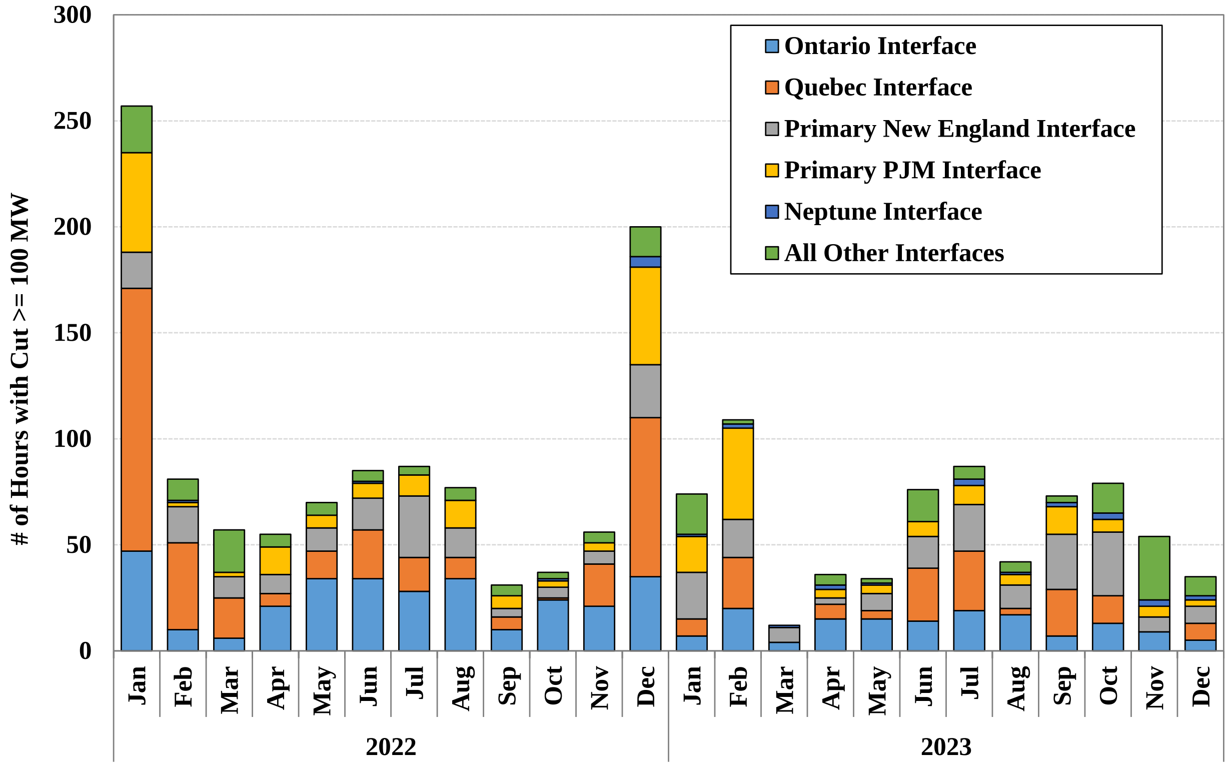
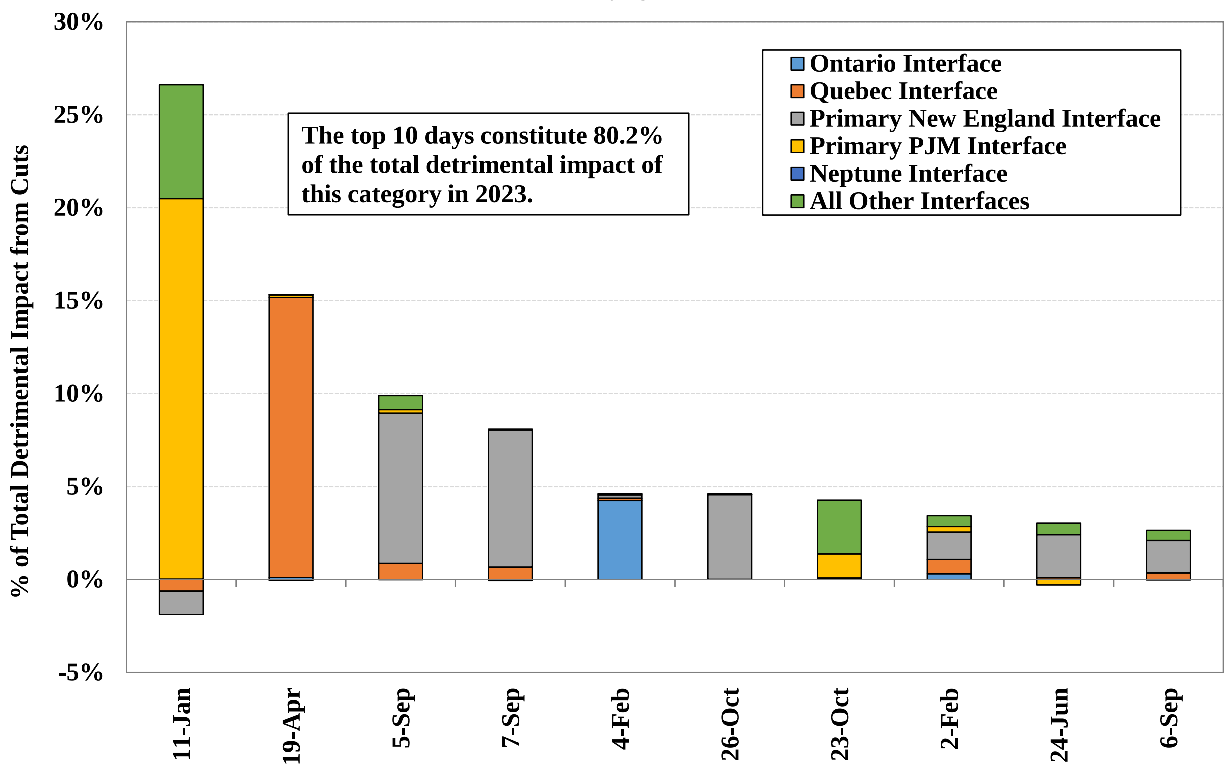


Figure A-78: Top 10 Days in Detrimental Curtailment Category
2023



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 2023:

- *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.

- *Real-Time Transient Price Volatility* – This subsection evaluates the factors that lead to transient price volatility in the real-time market.

- *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.

- *Market Operations and Prices on High Load Days* – This subsection evaluates the market effects of SRE commitments for capacity by NYISO and deployment of utility demand response programs by TOs on several high load days.

- *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.

- *Potential Design of Dynamic Reserves for Constrained Areas* – This subsection describes a modeling approach, in accordance with Recommendation 2015-16, with which locational reserve requirements and associated price signals could be dynamically determined based on load, transmission capability, and online generation.

- *Potential Design for Compensating Reserve Suppliers that Provide Congestion Relief* – This subsection describes a modeling approach, in accordance with Recommendation 2016-1, with which reserve suppliers that provide congestion relief in New York City could be properly compensated.

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.[306] 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.[307] RTC also schedules bids and offers to export, import, and wheel-through power to and from other control areas.

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306 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

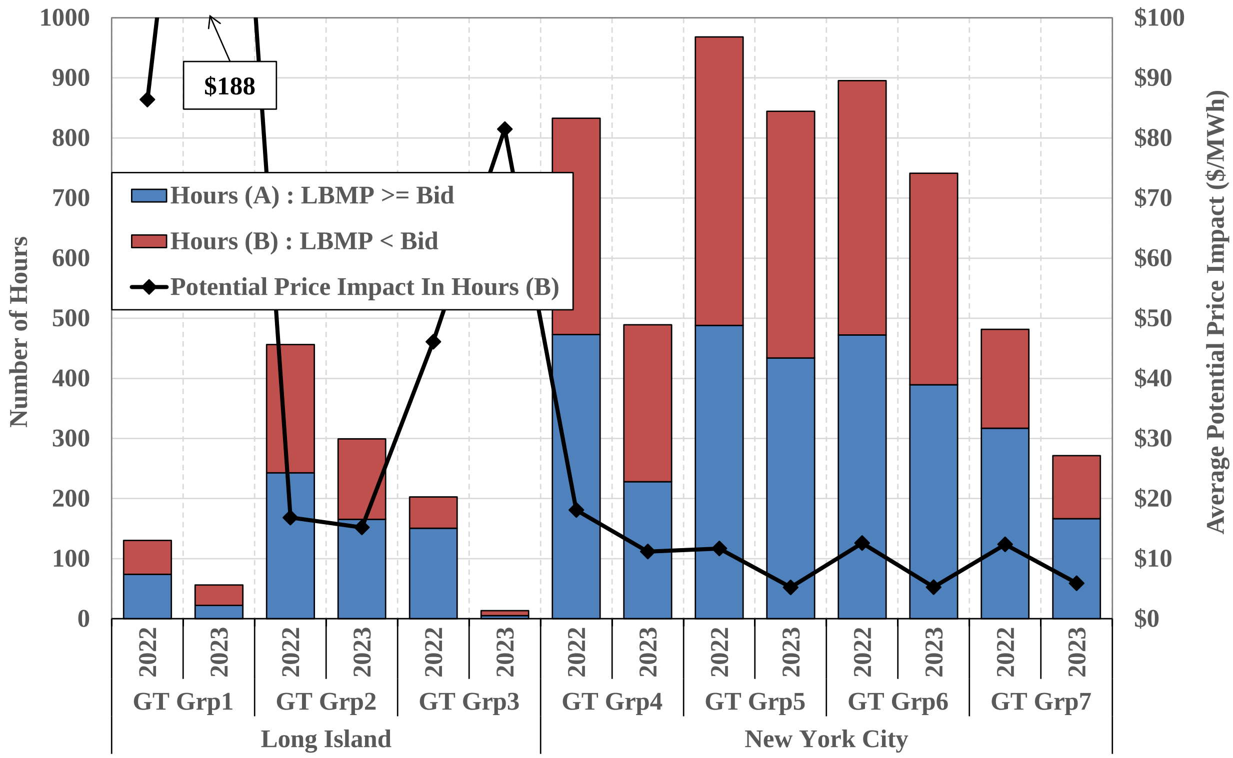
307 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

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-79: Real-Time Prices during Commitment of GTs with Multi-Hour MRT

Figure A-79 evaluates prices during commitments of gas turbines offering multi-hour minimum run times in the real-time market in 2022 and 2023. The evaluation focuses on economic commitments made by RTC, RTD, or RTD-CAM,[308] excluding self-schedules and out-of-market commitments made by operators.

Figure A-79: Prices During Commitments of GTs Offering Multi-Hour Min Run Times
2022-2023



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.

308 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.

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-80 & Figure A-81: 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.

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**

Figure A-80 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.

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-80: Duct Burner Real-Time Dispatch Issue
Example of a Failed RPU

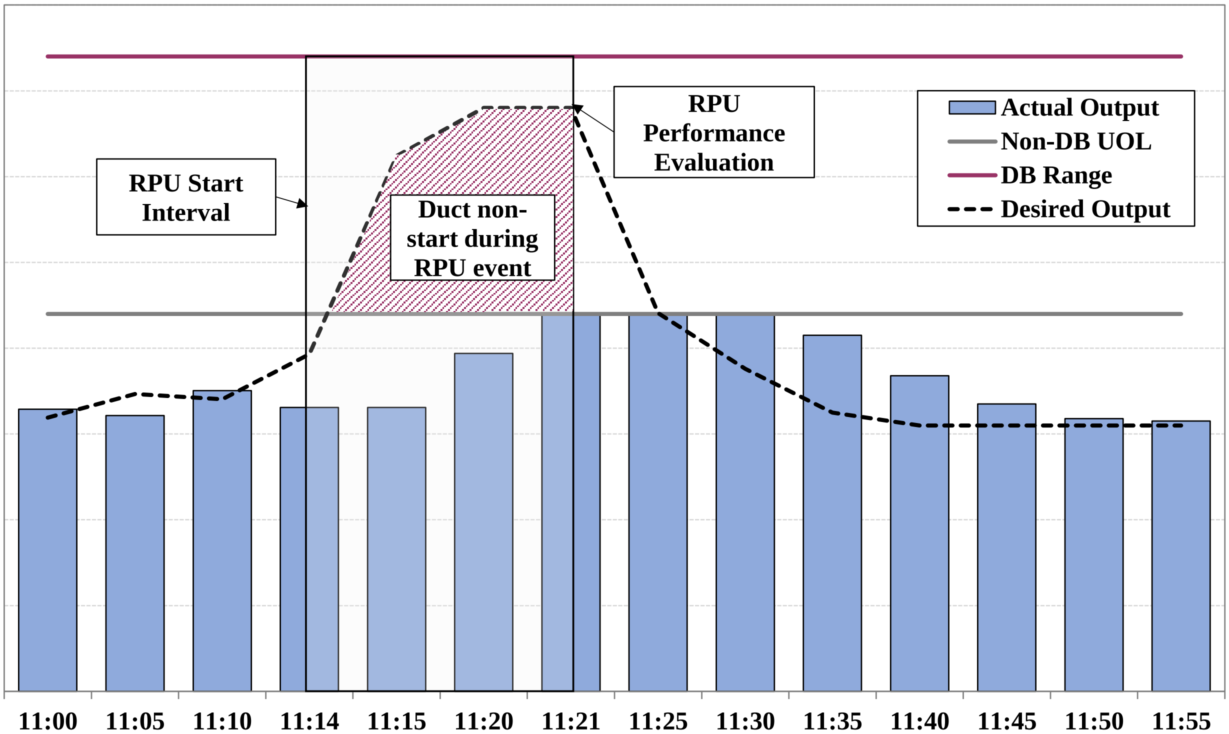


Figure A-81 examines duct burner availability in the real-time market for each quarter of 2023. The quantities in the charts are calculated for each 5-minute interval and then aggregated to the hourly level.

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-81: Evaluation of Duct-Burner Availability in Real-Time

2023

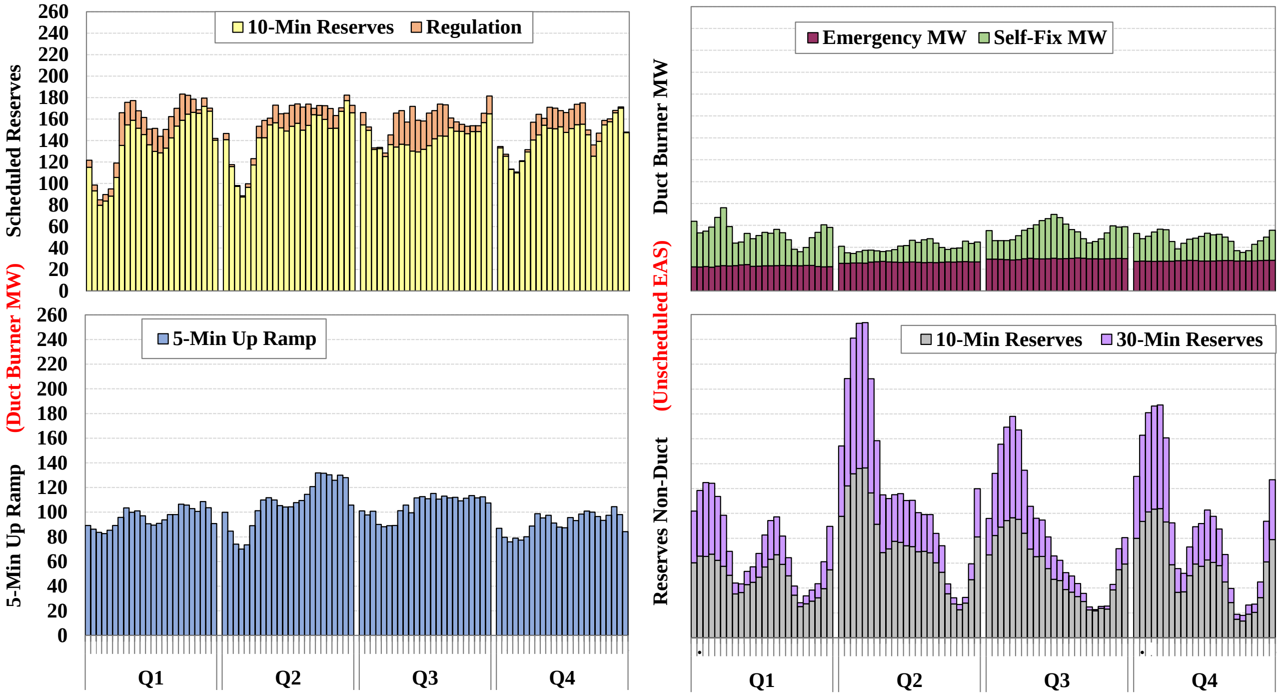


Figure A-82 & Figure A-83 – Ambient Impact on Duct Burner Availability Intraday

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. 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.

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-82 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-82: Illustration of Duct Burner Range
Example Generator Hourly Capability

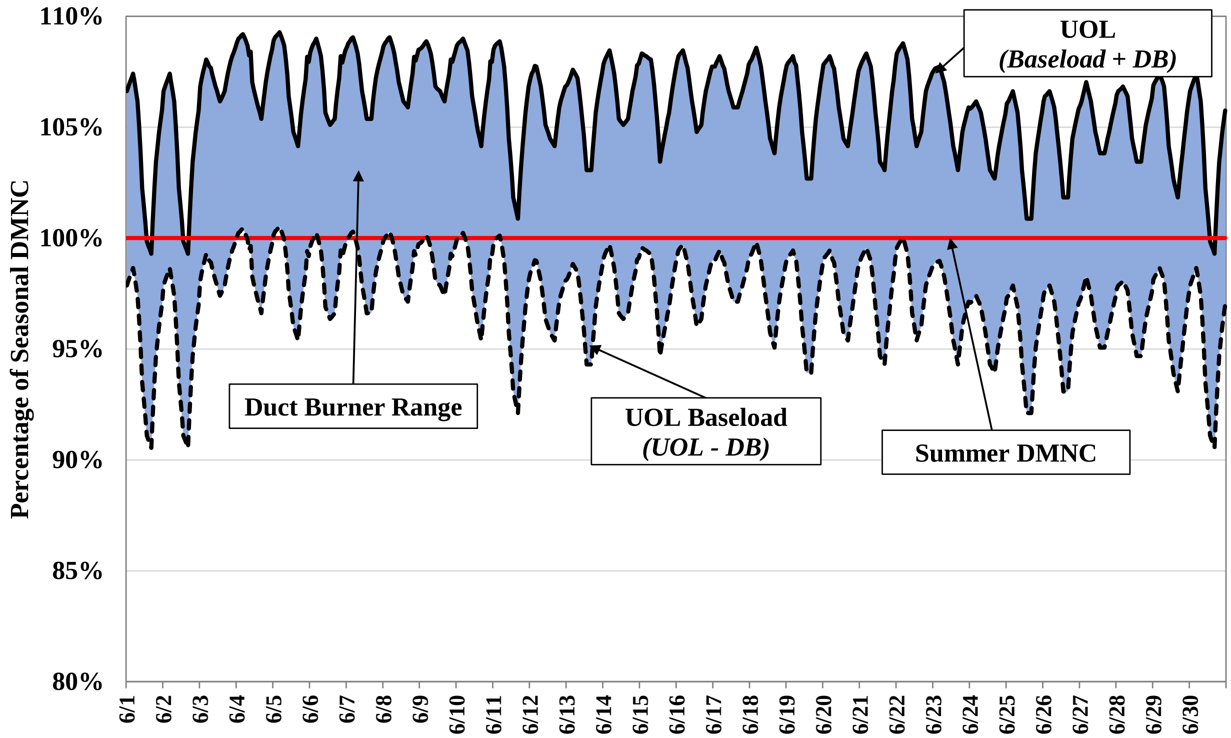


Figure A-83 displays how the availability of the duct burner range may be mischaracterized by static ramp rate ranges even when market participants actively adjust this parameter through the registration process. The figure shows the following two hourly average quantities:

- 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:

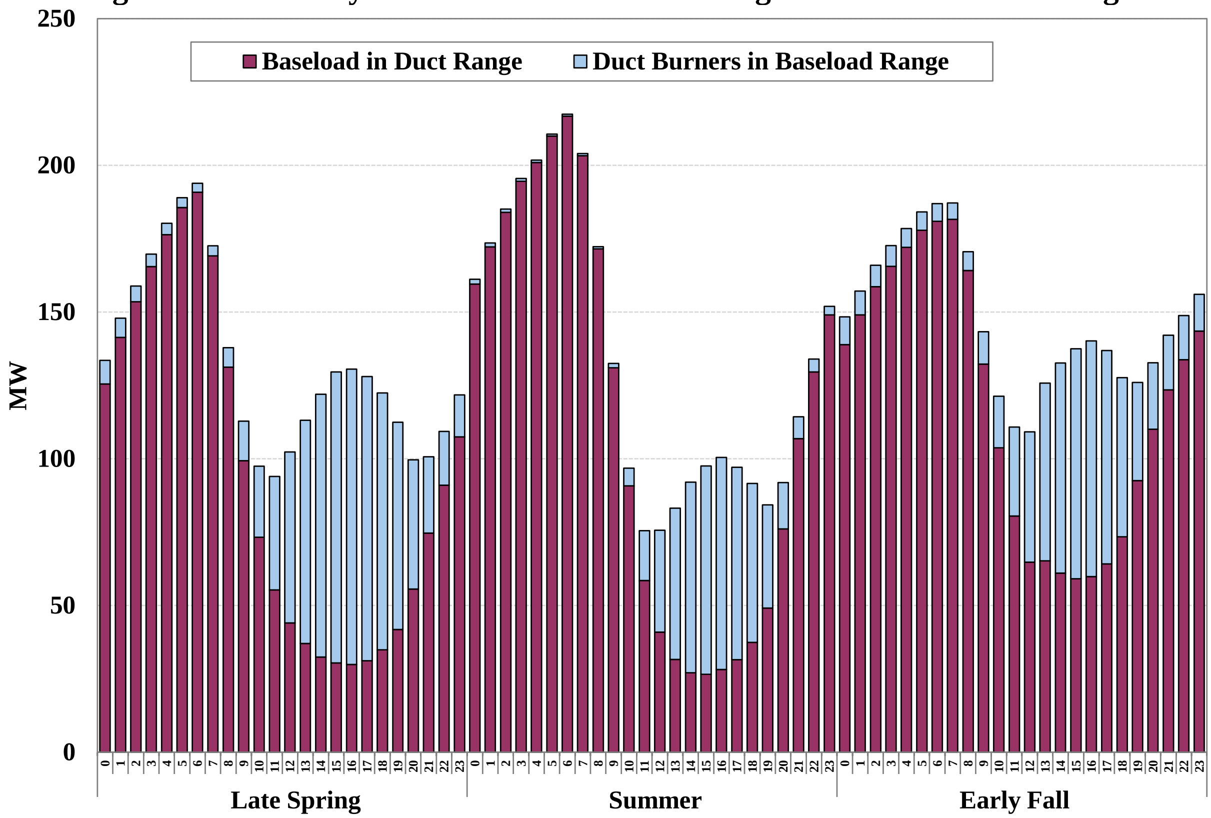
- *Late Spring:* includes the months of May and June;

- *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.[309] The results in the chart show how much capacity on average could be mischaracterized for combined cycle generators with duct burners.

Figure A-83: Hourly Limitations of Administering Static Duct Burner Ranges



C. Dispatch Performance of Intermittent Power Resources during Curtailments

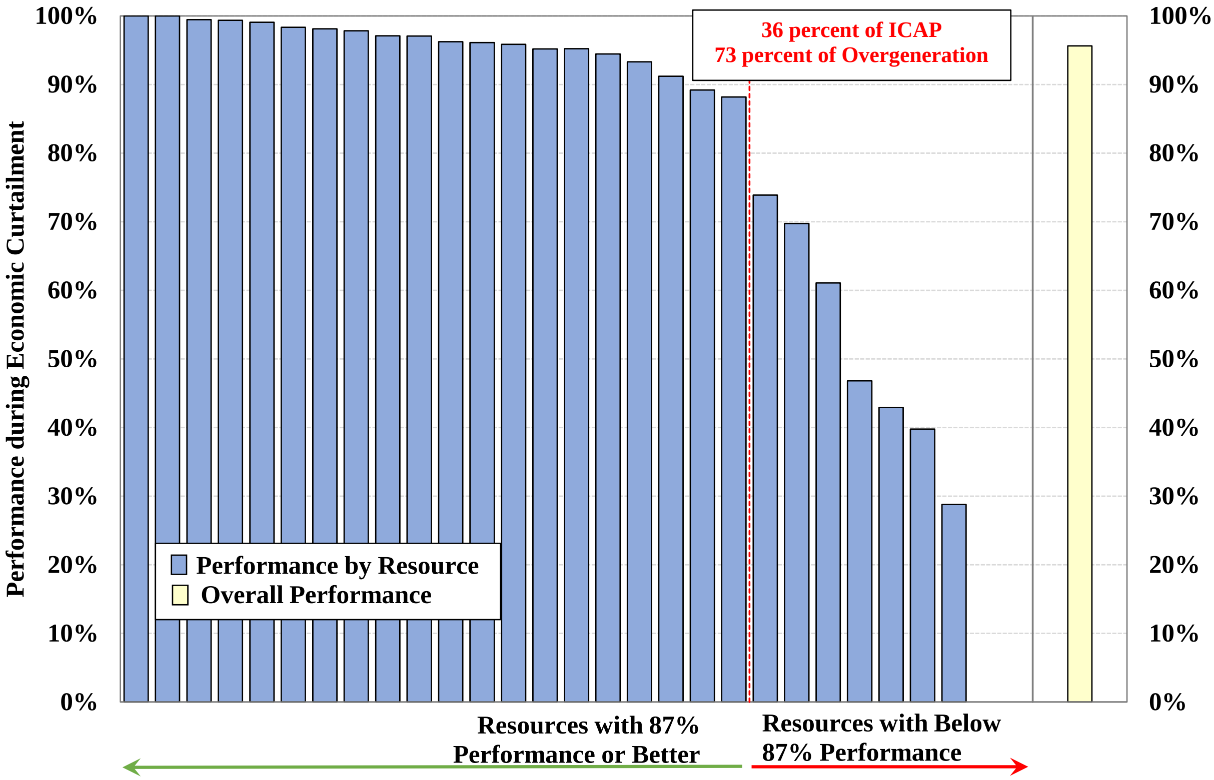
Figure A-84 displays the performance of individual Intermittent Power Resources ("IPRs") in 2023 when receiving an Output Limit (i.e., being curtailed). Results are shown for each unit that received a minimum of 10 RTD-intervals with an Output Limit (blue columns) and for all IPRs in aggregate (yellow column).[310] Performance is measured as the sum of overgeneration divided by expected curtailment by resource during all RTD intervals where an RTD Output Limit was

309 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.

310 Resource names are not given to protect confidentiality.

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.[311] Performance metrics are then calculated based on the total annual overgeneration divided by the total annual expected curtailment value.

Figure A-84: Performance of IPRs during Economic Curtailment
2023



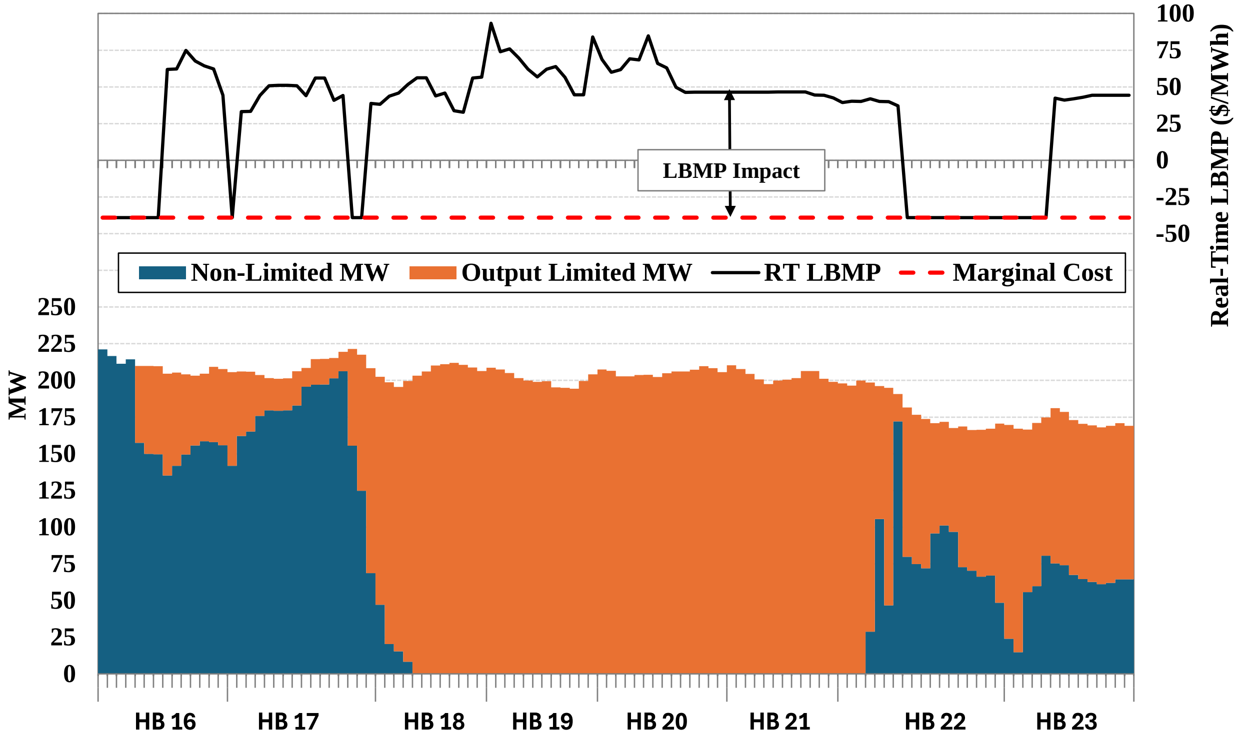
While most intermittent generators comply well with curtailment instructions, a small number of generators perform significantly worse than average. Figure A-85 shows the performance of one wind resource that did not respond appropriately during a January 2024 event. Since this unit did not respond to 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).

311 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-85: 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:[312]

$$(E_{RT} – E_{DA}) * LBMP_{RT} + P$$

Where:

E_{RT} = Real-time Actual Output in MW from the resource

E_{DA} = Day-ahead scheduled Output in MW from the resource

312 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.[313]

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-85), 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.

313 The overgeneration charge is based on the maximum of the day-ahead and real-time regulation capacity price for the impacted intervals.

Figure A-86 - Figure A-88 & Table A-10: Average GT Performance after a Start-Up Instruction

Figure A-86 to Figure A-88 summarize the performance of offline GTs in responding to start-up instructions that result from economic commitments (including commitment by RTC, RTD, and RTD-CAM).[314] The figure reports the average performance in 2022 and 2023. The unit's performance is measured based on its output level at its expected full output time (i.e., measured as the GT output at 10 or 30 minutes after receiving a start-up instruction, as a percent of its UOL).[315] Figure A-86 shows the performance evaluation for all GTs while Figure A-87 and Figure A-88 show the same evaluation separately for 10-minute and 30-minute GTs. Since 30-minute GTs cannot be started by either RTD-CAM or RTD, the two categories are excluded in Figure A-88.

For a particular type of start, the x-axis shows the share of starts in each range of performance. The length of the green bar represents the percent of starts in which the unit achieved at least 90 percent of its UOL by the expected full output time. Similarly, the blue, light blue, and orange bars represent the percent of GT starts in the following performance ranges: (a) from 80 to 90 percent; (b) 50 to 80 percent; and (c) 0 to 50 percent, respectively. The burgundy bars show the percent of GT starts that failed to produce any output within the expected start time.

The three figures also compare the performance for each start-up category to the performance of the associated units in the NYISO auditing process. Table A-10 also tabulates this comparison for 2023 with all categories of economic starts combined. The rows in the table provide the number of units in each performance range from 0 to 100 percent with a 10 percent increment. The left hand side of the table shows these numbers based on performance measured during economic starts, while the right hand side of the table shows numbers based on audit results. The units that are in service but were never started by RTC, RTD, or RTD-CAM in 2023 are placed in a separate category of "Not Evaluated", which also includes several units that we could not assess their performance reliably because of data issues. The following is an example read of the table: "21 GTs exhibited a response rate of 80 to 90 percent during economic starts in 2023, 21 of them were audited 58 times in total with 9 failures".

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314 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 nor self-started units.

315 For example, for a 40 MW 10-minute GT, if its output is 30 MW at 10 minute after receiving a start-up instruction, then its response rate is 75 percent, which falls into the 50-to-80-percent group.

Figure A-86: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, 2022 - 2023

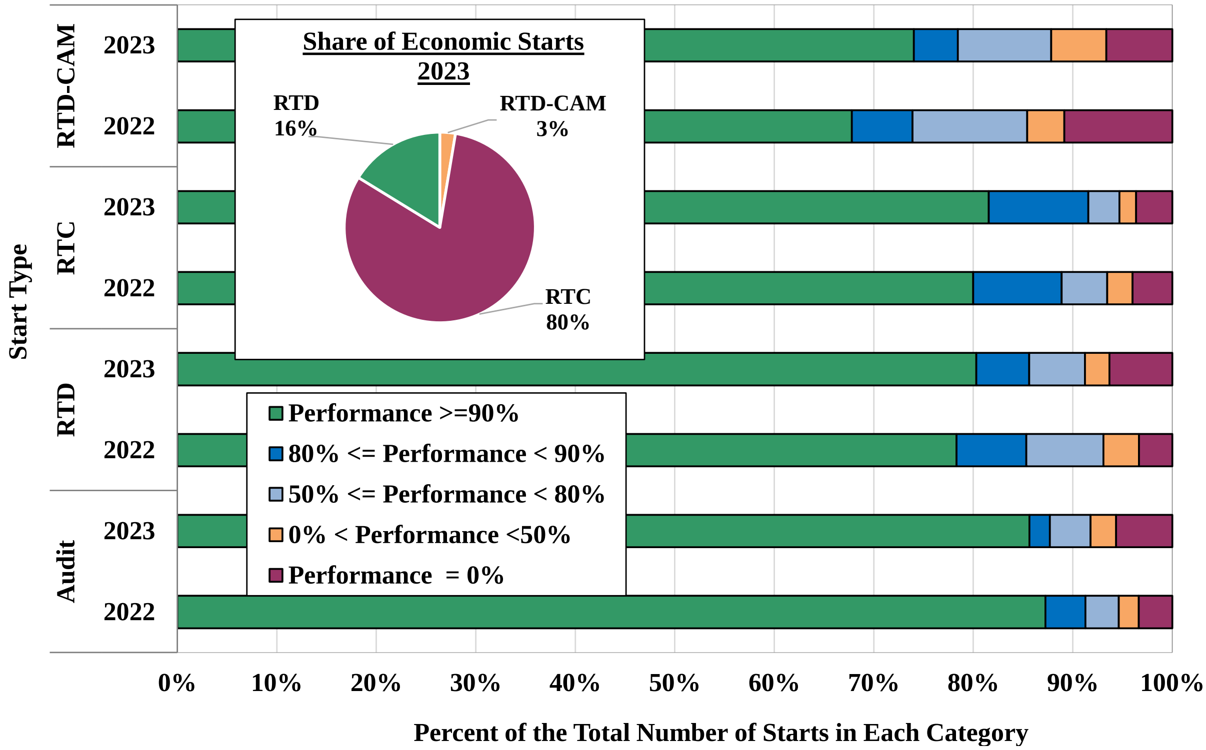


Figure A-87: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 10-Minute GTs, 2022 - 2023

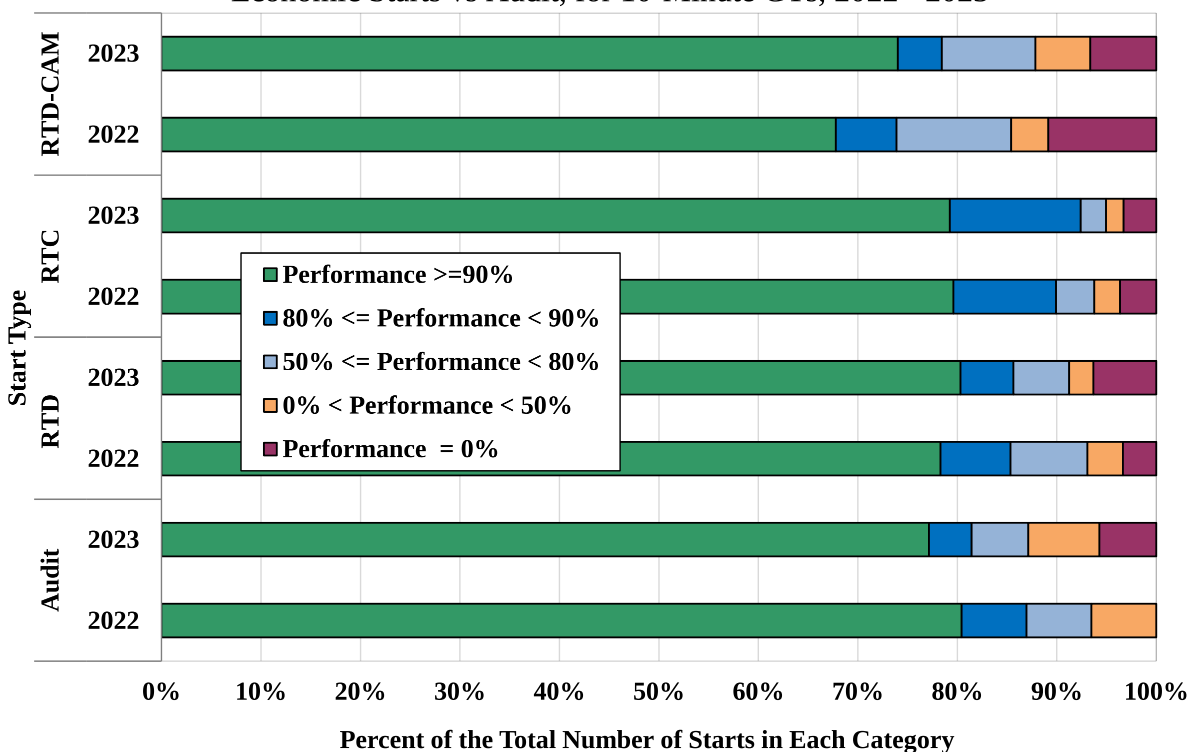


Figure A-88: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 30-Minute GTs, 2022 - 2023

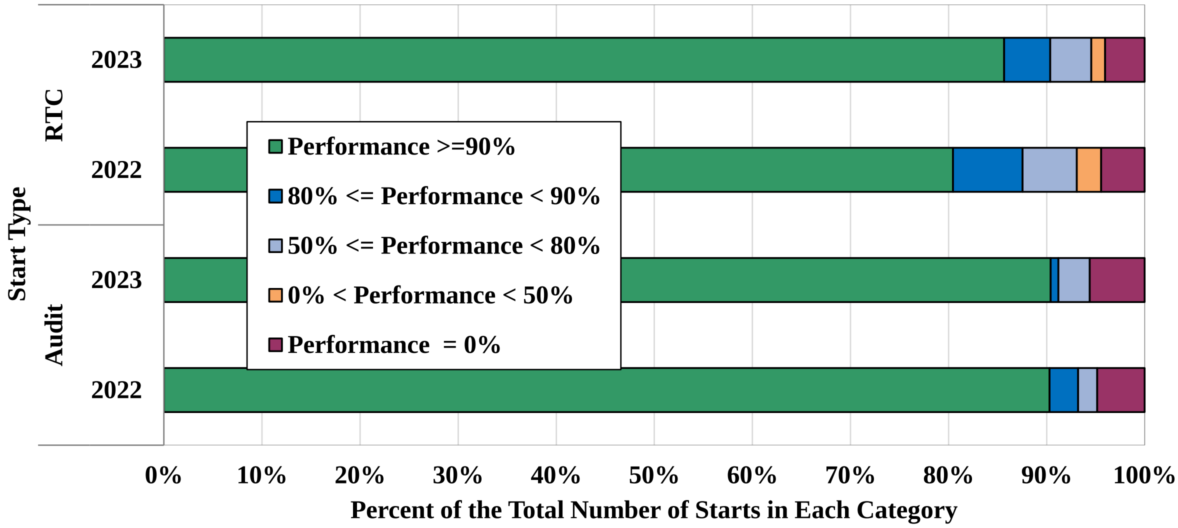


Table A-10: Economic GT Start Performance vs. Audit Results
2023

Economic GT Start Performance vs. Audit Results (Jan - Dec 2023)				
Economic GT Starts (RTC, RTD, and RTD-CAM)		GT Audit Results		
Performance Category	No. of Units	No. of Audits	Unique GTs Audited	No. of Audit Failures
Data Unavailable	7	12	7	0
0% - 10%	1	2	1	1
10% - 20%	0	0	0	0
20% - 30%	1	2	1	1
30% - 40%	1	6	1	4
40% - 50%	1	2	1	0
50% - 60%	4	20	4	13
60% - 70%	2	4	2	0
70% - 80%	10	23	10	3
80% - 90%	21	58	21	9
90% - 100%	55	174	55	9
TOTAL	**103**	**303**	**103**	**40**

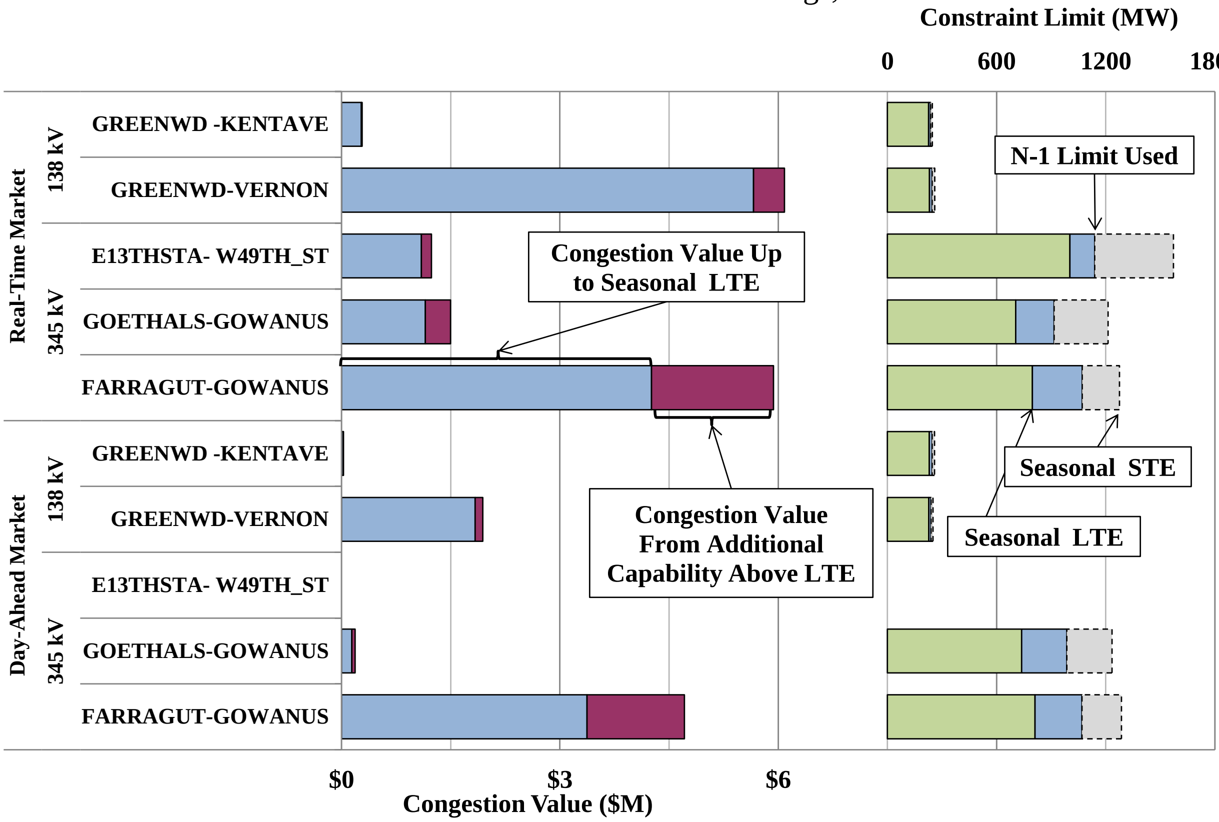
Figure A-89: Use of Operating Reserves to Manage Congestion in New York City

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-89 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 2023. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[316] The red bars represent the congestion values measured for the additional transfer capability above LTE.[317] 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-89: Use of Operating Reserves to Manage N-1 Constraints in New York City

Limits Used vs Seasonal LTE Ratings, 2023



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.[318] M2M includes two types of coordination:

316 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

317 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

318 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

- 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.[319]

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.[320]

Figure A-90: 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 2023.

Figure A-90 evaluates operations of these NY-NJ PARs under M2M with PJM in 2023 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:

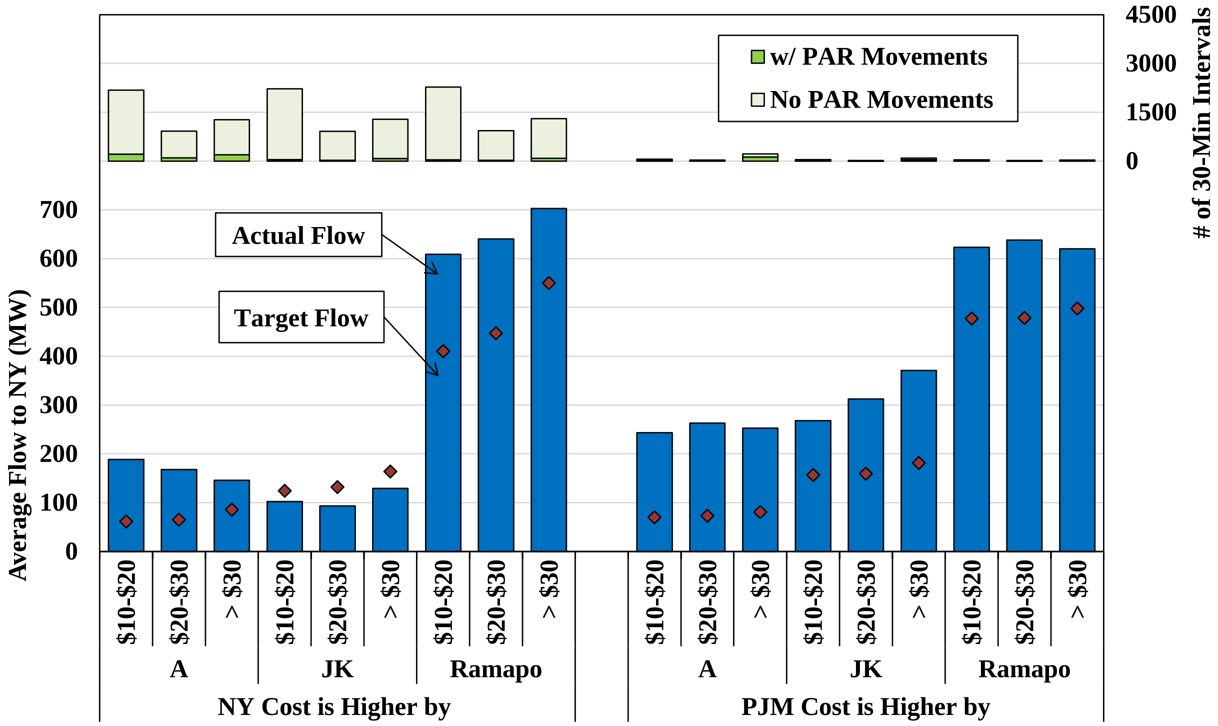
- When NY costs on relevant M2M constraints exceed PJM costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh.
- When PJM costs on relevant M2M constraints exceed NY costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh;

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 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).

319 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.

320 The list of pre-defined flowgates, *Coordinated Flowgates and Entitlements*, is posted here in the subgroup "Notices" under "General Information".

Figure A-90: NY-NJ PAR Operation under M2M with PJM
2023



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.[321] Such lines are analyzed in Section V.F of the Appendix, 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.

321 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.

Table A-11 and Figure A-91: 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 2023.

Table A-11 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2023. 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, the table 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.[322]

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.[323] For Ontario, the

[322] 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 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.

[323] 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

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.

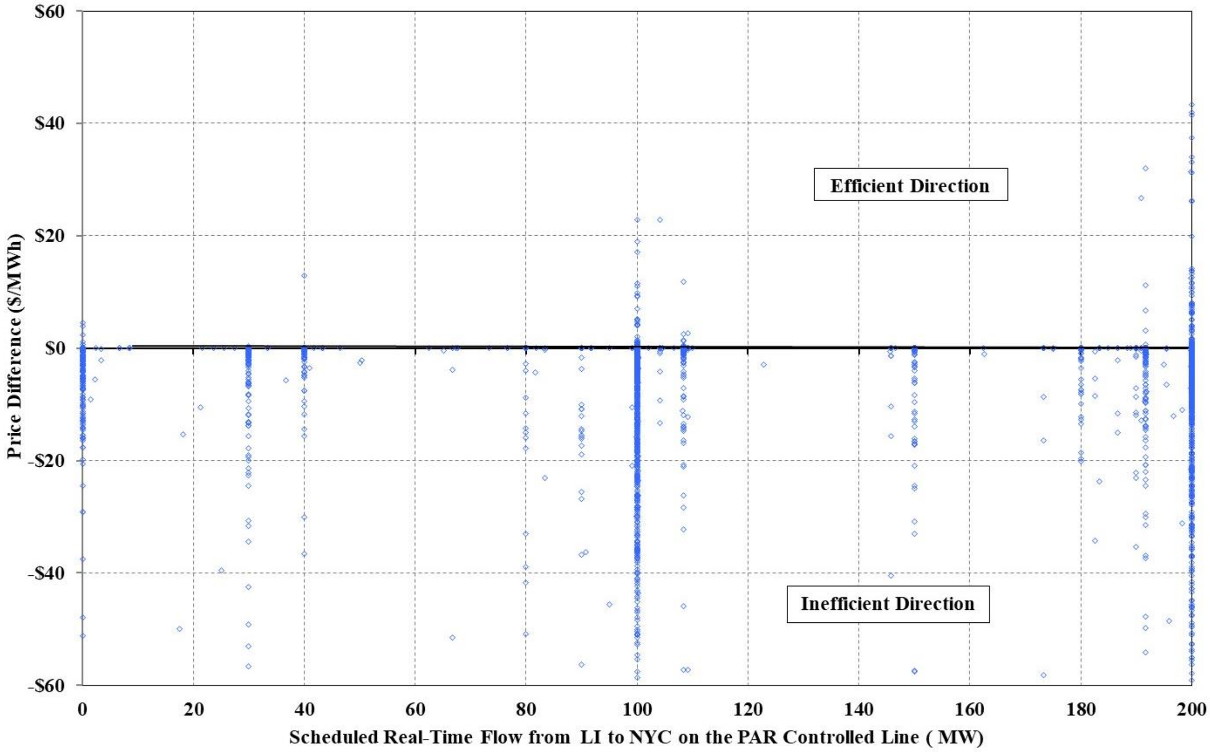
Table A-11: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2023

	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					-3	$1.49	55%	$1.4
New England to NYCA								
Sand Bar	-73	-$12.11	82%	$8	0	-$12.57	53%	$0.2
PJM to NYCA								
Waldwick	112	$6.76	83%	$8	18	$5.47	52%	-$1.1
Ramapo	406	$7.79	93%	$32	144	$6.86	73%	$11
Goethals	57	$8.00	83%	$5	114	$5.04	69%	$1.4
Long Island to NYC								
Lake Success	128	-$4.74	4%	-$6	-4	-$5.98	49%	$0.0
Valley Stream	78	-$5.35	3%	-$4	1.1	-$6.94	42%	-$0.1

Figure A-91 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.

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-91: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2023



G. Transient Real-Time Price Volatility

The New York ISO usually dispatches the real-time system and updates clearing prices once every five minutes. Real-time clearing prices can be quite volatile in wholesale electricity markets, even when sufficient supply is online. Generators (and demand response resources) are sometimes unable to adjust quickly enough to rapidly changing system conditions. As a result, wholesale markets experience brief periods of shortage, leading to very high prices; as well as brief periods of excess, leading to very low or even negative prices.

Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient market operations if generators are being cycled unnecessarily. Real-time price volatility also raises concerns because it increases risks for market participants, although market participants can hedge this risk by buying and selling in the day-ahead market and/or in the bilateral market. Generally, the ISO should seek ways to reduce unnecessary price volatility while maintaining efficient signals for generators to be flexible in real-time.

This sub-section evaluates scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2023. The effects of transient transmission constraints tend to be localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

A spike in the shadow price of a particular transmission constraint is considered *"transient"* if it satisfies both of the following criteria:

- It exceeds $150 per MWh; and
- It increases by at least 100 percent from the previous interval.

A spike in the shadow price of the power-balance constraint (known as the "reference bus price") affects prices statewide rather than in a particular area. A statewide price spike is considered *"*transient*"* if:

- The price at the reference bus exceeds $100 per MWh; and
- It increases by at least 100 percent from the previous interval.

Although the price spikes meeting these criteria usually account for a small number of the real-time pricing intervals, these intervals are important because they account for a disproportionately large share of the overall market costs. Furthermore, analysis of factors that lead to the most sudden and severe real-time price spikes provides insight about factors that contribute to less severe price volatility under a wider range of market conditions. In general, price volatility makes it more difficult for market participants, the NYISO, and neighboring system operators to commit quick-start resources and schedule external transactions efficiently. Hence, reducing unnecessary price volatility will lead to more efficient interchange between markets, lower production costs across markets, and less uplift from BPCG and DAMAP payments.

Table A-12: Transient Real-Time Price Volatility

Table A-12 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2023 for facilities exhibiting the most volatility. The table reports the frequency of transient price spikes, the average shadow price during the spikes, and the average transfer limit during the spikes.

The table also analyzes major factors that contributed to price volatility in these price spike intervals. These factors are grouped into three categories:

- Flows from resources scheduled by RTC
- Flow changes from non-modeled factors
- Other factors

Specifically, the table shows factors that contributed to an increase in flows from the previous five-minute interval. For the power-balance constraint, the table summarizes factors that contributed to an increase in demand and/or reduction in supply. This analysis quantifies contributions from the following factors, which are listed in order of significance:

- External Interchange – This adjusts as often as every 15 minutes, depending on the interface. The interchange at each interface is assumed to "ramp" over a 10-minute period from five minutes before the quarter hour (i.e., :55, :10, :25, :40) to five minutes after the quarter hour (i.e., :05, :20, :35, :50). Interchange schedules are determined before each 5-minute interval, so RTD must schedule internal dispatchable resources up or down to accommodate adjustments in interchange.

- Fixed Schedule PARs – These include PARs that are operated to a fixed schedule (as opposed to optimized PARs, which are operated to relieve congestion). The fixed schedule PARs that are the most significant drivers of price volatility include the A, J, K, and the 5018 lines (which are scheduled under the M2M process) and the 901 and 903 lines (which are used to support the ConEd-LIPA wheeling agreement).[324,325] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[326] but their flow is affected by changes in generation and load and changes in the settings of the fixed schedule PAR or other nearby PARs. Hence, RTD and RTC do not anticipate changes in flows across fixed schedule PARs in future intervals, which can lead to sudden congestion price spikes when RTD recognizes the need to redispatch internal resources in response to unforeseen changes in flows across a fixed schedule PAR.

- RTC Shutdown Peaking Resource – This includes gas turbines and other capacity that is brought offline by RTC based on economic criteria. When RTC shuts-down a significant amount of capacity in a single 5-minute interval, it can lead to a sudden price spike if dispatchable internal generation is ramp-limited.

- Loop Flows & Other Non-Market Scheduled – Includes flows that are not accounted for in the pricing logic of the NYISO's real-time market. These result when other system operators schedule resources and external transactions to satisfy their internal load, causing loop flow across the NYISO system. These also result from differences between the shift factors assumed by the NYISO for pricing purposes and the actual flows that result from adjustments in generation, load, interchange, and PAR controls.

- Self-Scheduled Generator – Includes units moving in accordance with a self-schedule, resources shut-down in accordance with a self-schedule, and resources shut down because they did not submit a real-time offer. In some cases, large inconsistencies arise between the ramp constraints in the physical and pricing passes of RTD for such units.

- Load – This includes the effects of changes in load.

- Generator Trip/Derate/Dragging – Includes adjustments in output when a generator trips, is derated, or is not following its previous base point.

- Wind – This includes the effects of changes in output from wind turbines.

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324 These lines are discussed further in Subsection F.

325 M2M coordination is discussed further in Subsection E.

326 The flows over the A, JK, and 5018 lines are assumed to be fixed in future intervals at the most recent telemetered value plus a portion of expected changes of interchanges between PJM and New York over its primary interface.

- Redispatch for Other Constraint (OOM) – Includes adjustments in output when a generator is logged as being dispatched out-of-merit order. Typically, this results when a generator is dispatched manually for ACE or to manage a constraint that is not reflected in the real-time market (i.e., in RTD or RTD-CAM).

- Re-Dispatch for Other Constraint (RTD) – Multiple constraints often bind suddenly at the same time because of some common causal factors. For example, the sudden trip of a generator could lead to a power-balance constraint and a shortage of 10-minute spinning reserves. In such cases, some units are dispatched to provide more energy, while others may be dispatched to provide additional reserves, so the units dispatched to provide additional reserves would be identified in this category. The analysis does not include this category in the total row of Table A-12, since this category includes the responses to a primary cause that is reflected in one of the other rows.

The contributions from each of the factors during transient spikes are shown in MWs and as a percent of the total contributions to the price spike for the facility. For each constraint category, we highlight the category of aggravating factors that most contributed to the transient price spike in purple. We highlight the largest sub-categories in green.

Table A-12: Drivers of Transient Real-Time Price Volatility

2023

	Power Balance		West Zone Lines		Central East		Upstate to Long Island		Intra-LI Constraints		Capital to Hud VL		NYC Load Pockets		North to Central		West to Central	
Average Transfer Limit	**n/a**		**255**		**1037**		**810**		**217**		**617**		**363**		**163**		**177**	
Number of Price Spikes	**168**		**31**		**522**		**389**		**1502**		**154**		**604**		**129**		**351**	
Average Constraint Shadow Price	**$299**		**$846**		**$468**		**$356**		**$426**		**$795**		**$690**		**$625**		**$587**	
Source of Increased Constraint Cost:	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Scheduled By RTC	**190**	**63%**	**0**	**0%**	**37**	**47%**	**32**	**50%**	**6**	**60%**	**8**	**24%**	**4**	**29%**	**2**	**33%**	**1**	**11%**
External Interchange	104	35%	0	0%	16	21%	14	22%	1	10%	6	18%	1	7%	2	33%	1	11%
RTC Shutdown Resource	63	21%	0	0%	14	18%	15	23%	3	30%	1	3%	2	14%	0	0%	0	0%
Self Scheduled Shutdown/Dispatch	23	8%	0	0%	7	9%	3	5%	2	20%	1	3%	1	7%	0	0%	0	0%
Flow Change from Non-Modeled Facto	**7**	**2%**	**8**	**80%**	**28**	**36%**	**13**	**20%**	**3**	**30%**	**23**	**68%**	**9**	**64%**	**2**	**33%**	**5**	**56%**
Loop Flows & Other Non-Market	4	1%	8	80%	8	10%	6	9%	3	30%	19	56%	4	29%	1	17%	3	33%
Fixed Schedule PARs	0	0%	0	0%	20	26%	5	8%	0	0%	4	12%	5	36%	1	17%	2	22%
Redispatch for Other Constraint (OOM)	3	1%	0	0%	0	0%	2	3%	0	0%	0	0%	0	0%	0	0%	0	0%
Other Factors	**104**	**35%**	**2**	**20%**	**13**	**17%**	**19**	**30%**	**1**	**10%**	**3**	**9%**	**1**	**7%**	**2**	**33%**	**3**	**33%**
Load	59	20%	0	0%	10	13%	15	23%	1	10%	1	3%	0	0%	1	17%	0	0%
Generator Trip/Derate/Dragging	19	6%	0	0%	2	3%	4	6%	0	0%	2	6%	1	7%	0	0%	0	0%
Wind	26	9%	2	20%	1	1%	0	0%	0	0%	0	0%	0	0%	1	17%	3	33%
Total	**301**		**10**		**78**		**64**		**10**		**34**		**14**		**6**		**9**	
Redispatch for Other Constraint (RTD)	**70**		**0**		**10**		**2**		**1**		**1**		**10**		**4**		**4**	

H. 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, [327] 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-92 & Figure A-93: Regulation Movement-to-Capacity Ratio

Figure A-92 shows a distribution of actual movement-to-capacity ratio of all scheduled regulation suppliers from one sample day. The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio. The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the multiplier of 8 that is used for all resources when formulating the composite regulation offer.

Figure A-92: Distribution of Actual Regulation Movement-to-Capacity Ratio
From a Sample Day

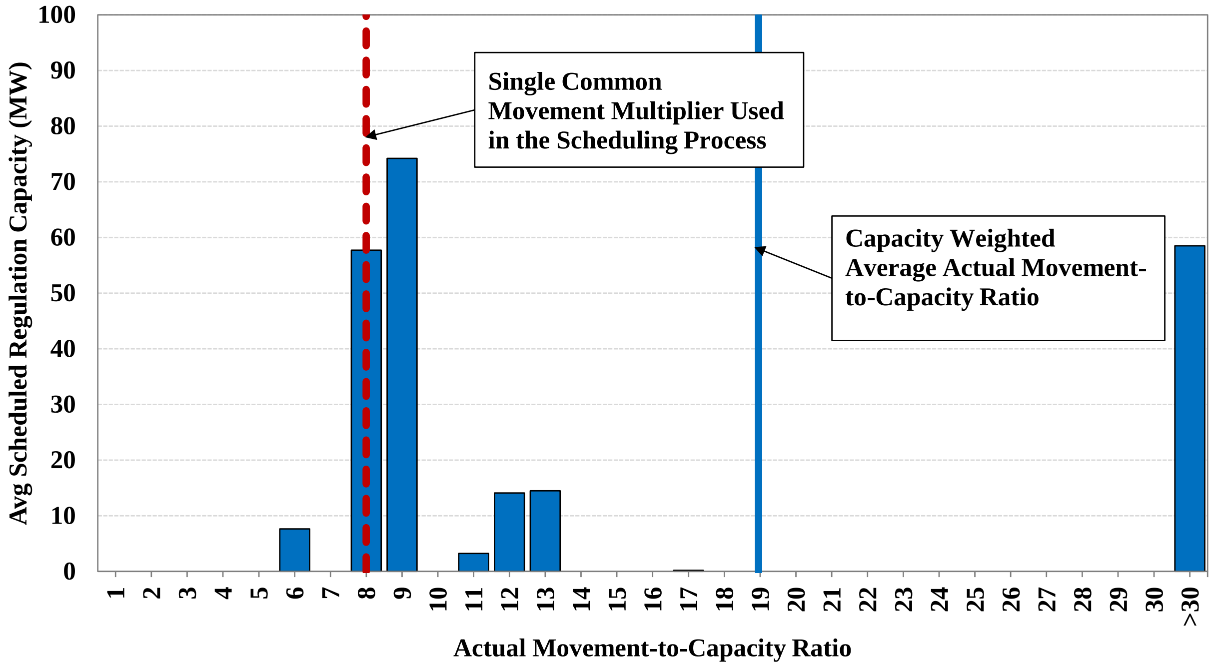
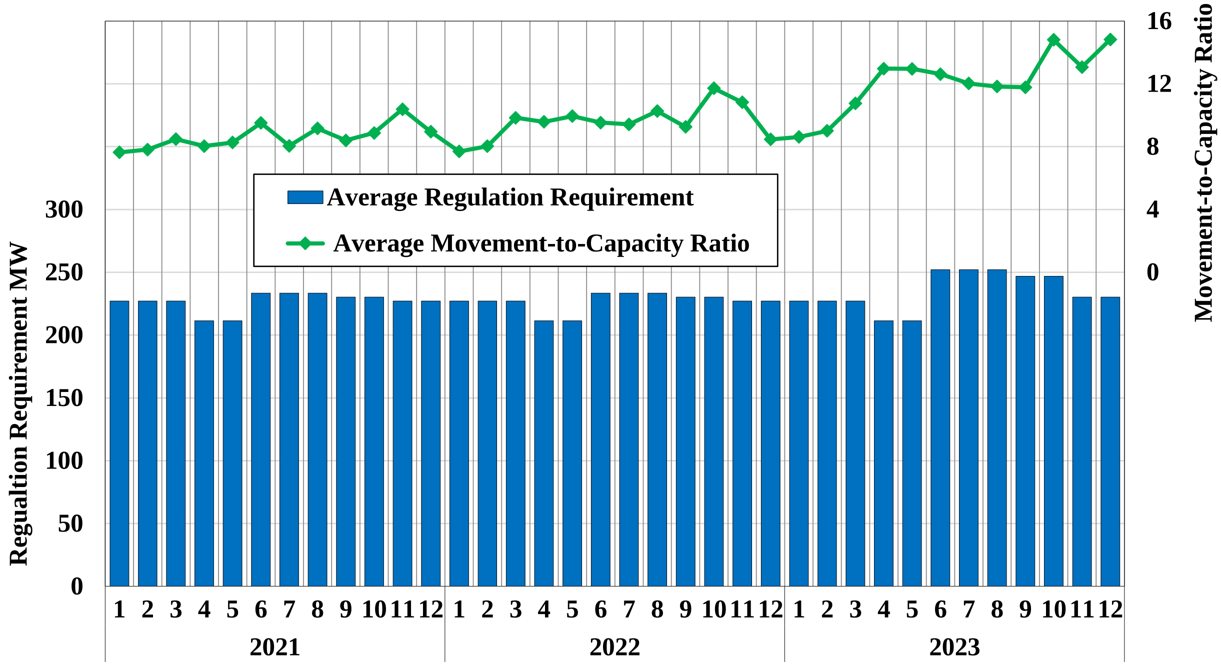


Figure A-93 tracks the variation of regulation movement-to-capacity ratio in recent years, summarizing the following quantities by month:

- 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.

[327] The uniform Regulation Movement Multiplier was changed from 13 to 8 on August 31, 2021.

Figure A-93: Regulation Requirement and Movement-to-Capacity Ratio
By Month, 2021-2023



I. 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 the NYISO's market design that facilitate shortage pricing. First, the NYISO uses operating reserves and regulation demand curves to set real-time clearing prices during operating reserves and regulation shortages. Second, the NYISO uses a transmission demand curve to set real-time clearing prices during a portion of transmission shortages. Third, the 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 2023:

- Shortages of operating reserves and regulation (evaluated in this Subsection); and

- Transmission shortages (evaluated in Subsection J).

Figure A-94: Real-Time Prices During Physical Ancillary Services Shortages

The 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-94 summarizes physical ancillary services shortages and their effects on real-time prices in 2022 and 2023 for the following eight categories: [328]

- 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.

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328 See *NYISO Ancillary Services Manual* for more details.

- 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.

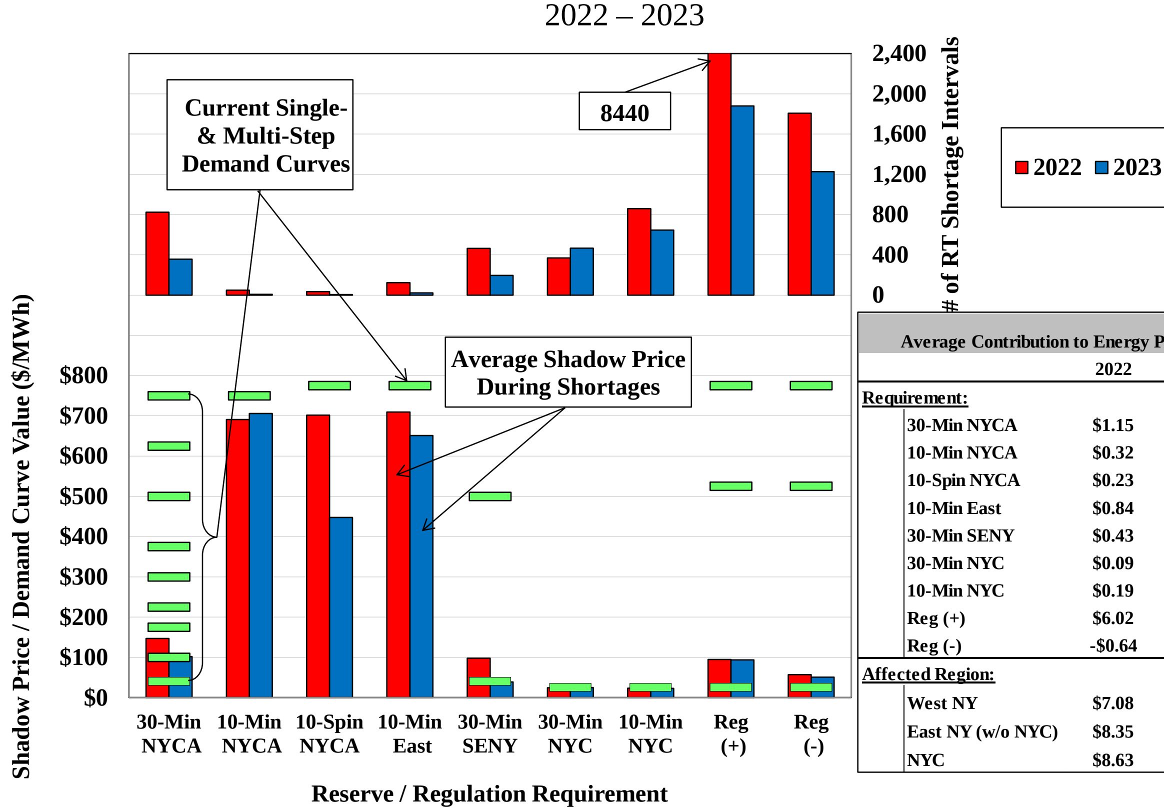
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency 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.

- 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-94: Real-Time Prices During Ancillary Services Shortages
2022 – 2023



Average Contribution to Energy Price	2022	2023
Requirement:		
30-Min NYCA	$1.15	$0.35
10-Min NYCA	$0.32	$0.05
10-Spin NYCA	$0.23	$0.03
10-Min East	$0.84	$0.13
30-Min SENY	$0.43	$0.07
30-Min NYC	$0.09	$0.11
10-Min NYC	$0.19	$0.14
Reg (+)	$6.02	$1.32
Reg (-)	-$0.64	-$0.36
Affected Region:		
West NY	$7.08	$1.38
East NY (w/o NYC)	$8.35	$1.58
NYC	$8.63	$1.83

Figure A-95 & Table A-13: Reserves Shortages in New York City

The 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 2023. 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
2023

	RT Reserve Shortages in NYC in 2023		
Month	**# Intervals**	**Avg. Shortage MW**	**#Intervals w/ toNYC Congestion**
Jan	21	158	0
Feb	3	28	0
Mar	0	0	0
Apr	50	41	0
May	27	67	2
Jun	41	50	0
Jul	205	81	0
Aug	32	26	0
Sep	344	366	0
Oct	150	80	20
Nov	115	79	0
Dec	18	36	0
Total	**1006**	**173**	**22**

Figure A-95 illustrates a sample real-time shortage event on September 5, 2023. 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 10 to the end of hour 22 the figure shows:

- The amount of reserve shortages (red bar); and

- Net imports from upstate areas (blue bar).[329]

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.

Figure A-95: Real-Time Reserve Shortages in New York City
Sample Event on September 5, 2023

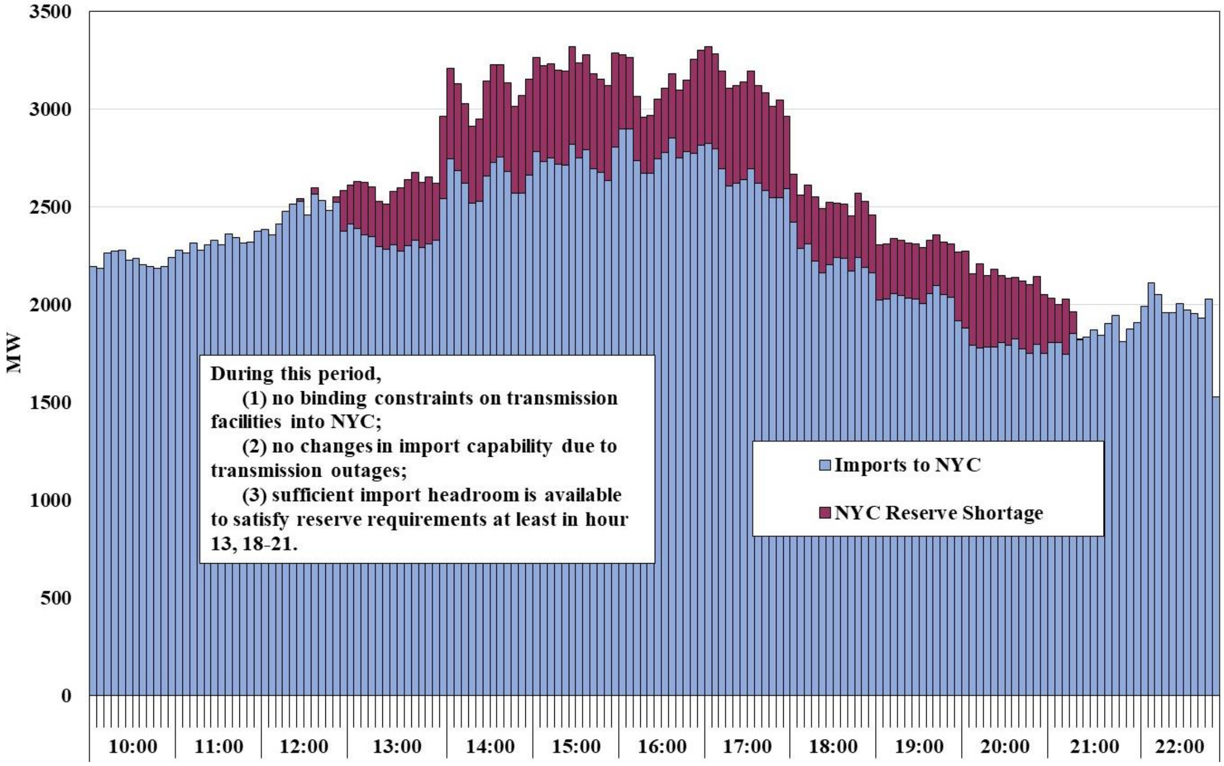


Figure A-96: Comparison of Shortage Pricing in NYISO and Neighboring Markets

In recent years, shortage pricing values in the neighboring PJM and ISO-NE regions have increased dramatically relative to NYISO. ISO-NE implemented Pay-for-Performance in its capacity market in 2018, which provides real-time performance incentives of $3,500/MWh, rising to $5,455/MWh in 2024 and $9,337/MWh in 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

329 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).

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-96 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.[330]

Figure A-96: Shortage Pricing in NYISO vs. Neighboring Markets

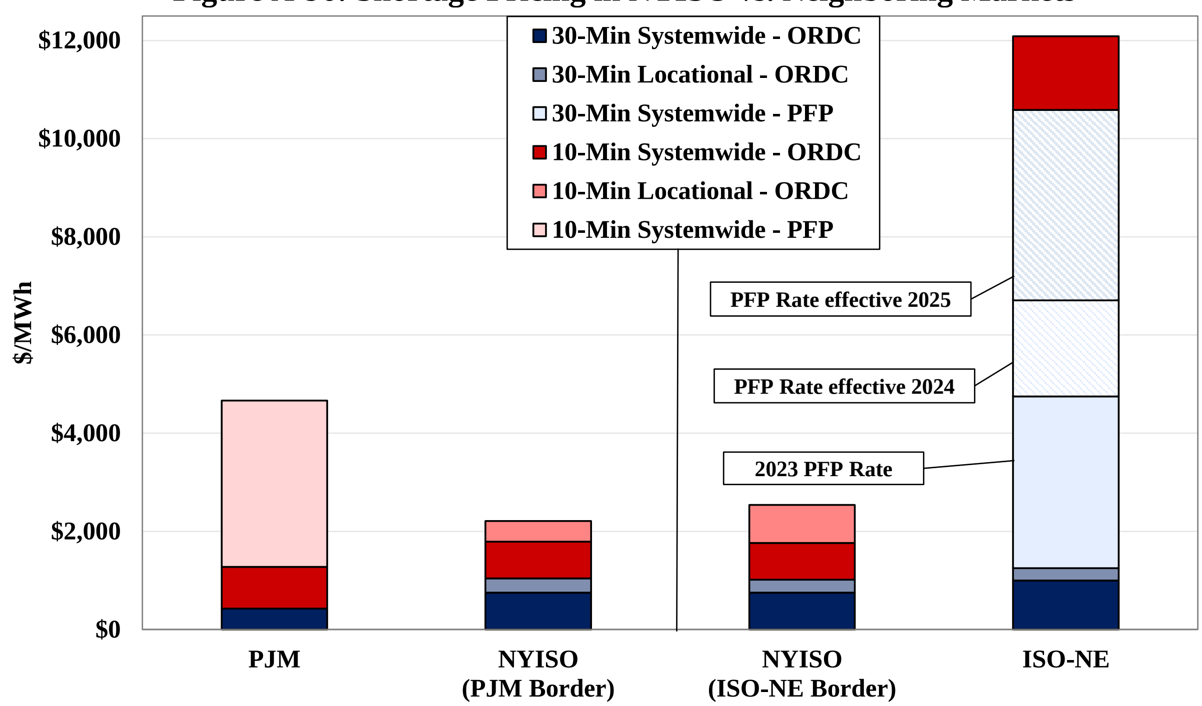


Figure A-97 - Figure A-99: NYISO ORDCs vs. MMU EVOLL Curve

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

330 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.

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 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 uncertain 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:

$$\textit{Modeled Capacity} = \textit{ICAP} * \textit{Participation Factor}$$

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 purposes of this analysis, we only consider land-based wind resources, given the limited capacity currently available from in-service utility-scale solar, offshore wind, and battery storage resources within the NYISO market, while BTM solar is reflected in the net load forecast error. 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 they have been scheduled by RTC for various reasons, including 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 historic 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 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-97 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.

The EVOLL curves are compared with 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 sum of the 10-Spin ORDC and 10-Minute ORDC as shown in Figure A-98. The analysis reveals that the current ORDCs significantly undervalue 10-minute reserves when the available quantity drop below 600 MW. Moreover, the MMU EVOLL curve shows that 10-minute reserves have reliability value beyond the existing 1310 MW requirement. This supports the NYISO's proposal to use a relatively low ORDC to hold 10-minute reserves quantities above 1,310 MW to address uncertainty in load and intermittent generation.[331]

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-99 shows this MMU economic 30-minute ORDC, compared to the current 30-minute ORDC.

331 See *Balancing Intermittency: Percentiles and Shortage Pricing Curves,* ICAPWG/MIWG, March 4, 2024.

Figure A-97: NYISO ORDC vs. MMU EVOLL Curve

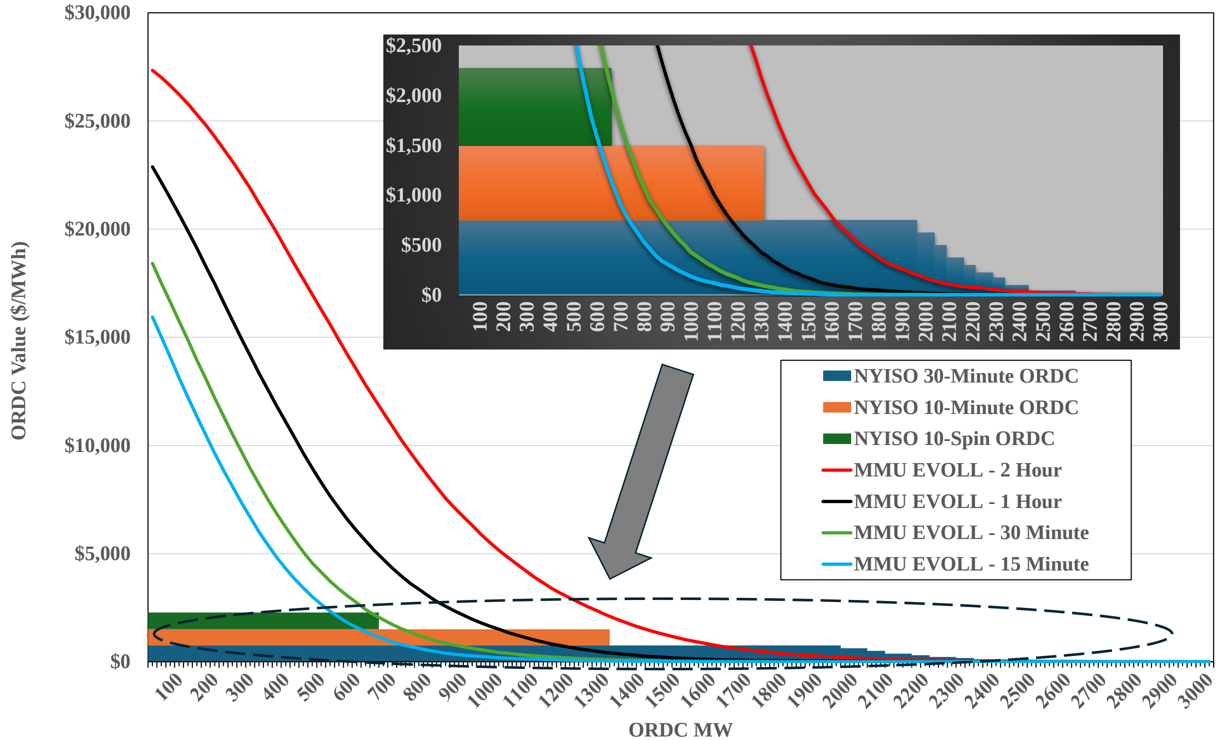


Figure A-98: NYISO ORDC vs. MMU EVOLL Curve
10-Minute Reserves

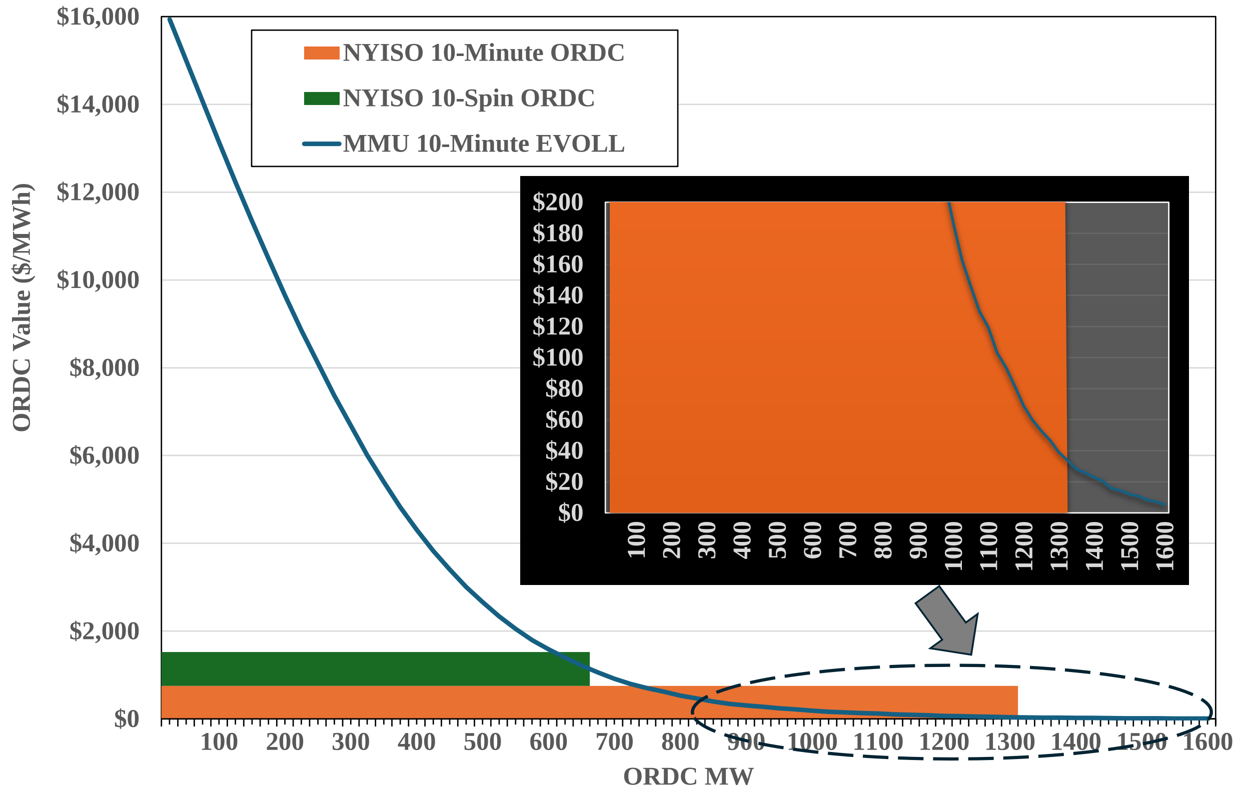
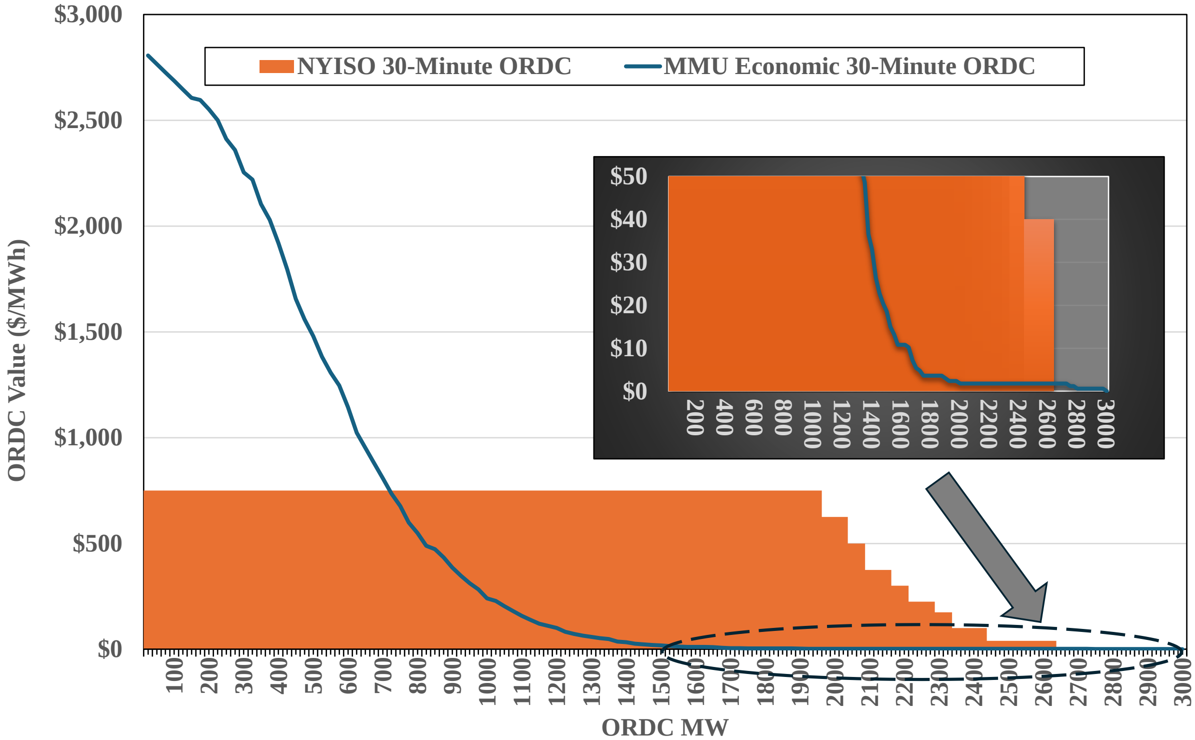


Figure A-99: NYISO ORDC vs. MMU EVOLL Curve
30-Minute Reserves



J. Real-Time Prices During Transmission Shortages

Transmission shortages occur when power flows exceed the limit of a transmission constraint. Transmission shortages may compel the ISO to shed firm load to maintain system security, but in most cases, transmission shortages persist for many hours without load shedding or damage to equipment. During transmission shortages, it is important for wholesale markets to set efficient prices that appropriately reflect the acuteness of operating conditions. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes.

If the available physical capacity is not sufficient to resolve a transmission constraint, a Graduated Transmission Demand Curve ("GTDC"), combined with the constraint relaxation (which increases the constraint limit to a level that can be resolved) under certain circumstances, will be used to set prices under shortage conditions. The NYISO first adopted the GTDC approach on February 12, 2016, [332] and made two subsequent enhancements to improve market efficiency during transmission shortages. [333] [334]

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. A default CRM value of 20 MW is used for most facilities across the system regardless of their actual physical limits. This often overly restricted transmission constraints with small physical limits. Starting in December 2018, a CRM of 10 MW was used on 115 kV facilities in the Upstate area.

This subsection evaluates market performance during transmission shortages in 2023, focusing on the use of the GTDC and the CRM. In addition, a condition similar to a shortage occurs when the available capacity from an offline quick-start gas turbine is counted towards resolving a transmission constraint, but the gas turbine is not given a startup instruction.[335] 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 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. [336] This category of shortage is evaluated in this section. The analyses in this subsection only include data prior to November 14, 2023 when the new GTDC became effective. Future reports will evaluate market performance under the new curve.

Figure A-100, Table A-14,& Figure A-101: RT Congestion Management with GTDCs

Figure A-100 examines the use of the GTDC during transmission shortages in the real-time market by constraint group in 2023.

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332 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.

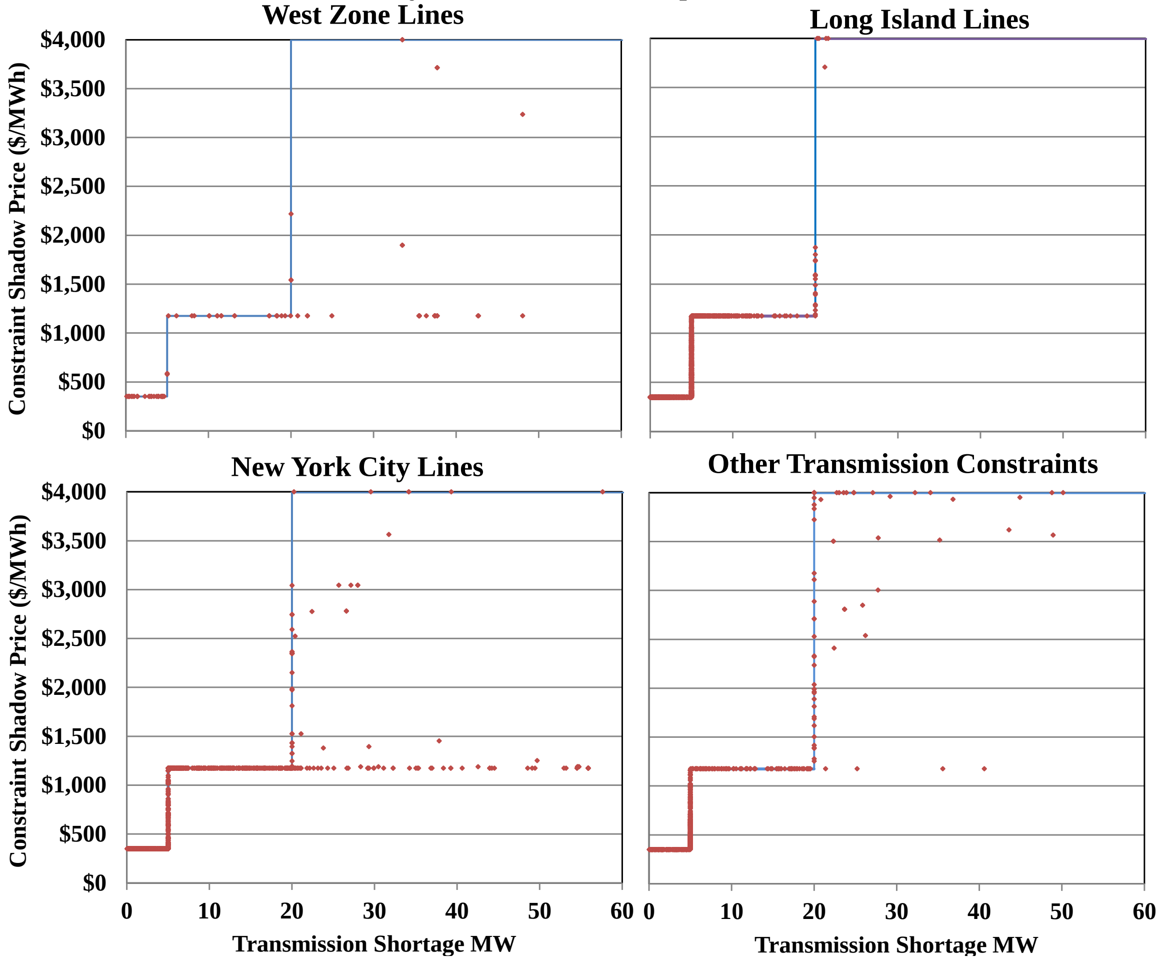
333 The first enhancement was made on June 20, 2017. Key changes include: 1) modifying the second step of the GTDC from $2350 to $1175/MWh; and 2) removing the "feasibility screen" and applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM"). These changes are discussed in detail in Commission Docket ER17-1453-000.

334 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.

335 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.

336 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-100: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2023



In each of the four scatter plots, every point represents a binding transmission constraint during a 5-minute interval, with the amount of transmission shortage (relative to the BMS limit adjusted for the CRM)[337] showing on the x-axis and the constraint shadow price on the y-axis.

Table A-14 evaluates the congestion-relief effect from offline GTs and the effect of the CRM on different transmission constraints in 2023. The table summarizes the following quantities for constraints by facility voltage class and by location for facilities that have a 10+ MW CRM:

- The number of constraint-shortage intervals – For each facility group, this includes: (a) the average transmission shortage quantity that is recognized in the market model; and (b) additional shortages when removing the congestion-relief effect from offline GTs.

337 BMS limit is the constraint limit that is used in the market dispatch model. For example, if a constraint has a 1000 MW BMS limit and a 20 MW CRM, the shortage quantities reported here are measured against a constraint limit of 980 MW.

- Average shortage quantity – Includes: (a) average shortage MW recognized in the market model; and (b) additional shortages if congestion-relief from offline GTs is removed.

- Average constraint limit – This indicates the average transmission limit overall all transmission constraints in each facility group.

- Average CRM – This indicates the average CRM MW used in each facility group.

- CRM as a percent of limit – This is the average CRM as a percentage of average limit.

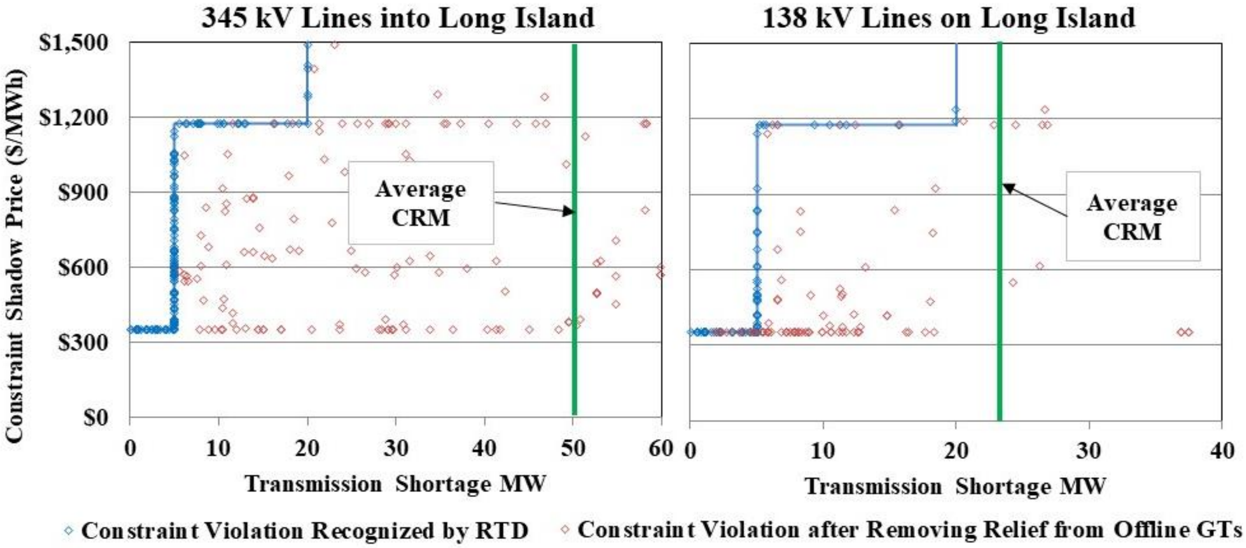
Table A-14: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2023

Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals		Avg Shortage MW		Avg Constraint Limit (MW)	Avg CRM (MW)	CRM as % of Limit
		Recognized in Model	Excluding Offline GT	Recognized in Model	Excluding Offline GT			
69 kV	Long Island	2482	2514	4	4	112	10	9%
115 kV	West	80	80	16	16	155	10	6%
	North	467	467	7	7	137	10	7%
	All Others	952	955	9	9	197	10	5%
138 kV	New York City	1092	1093	8	8	254	21	8%
	Long Island	1093	1418	3	6	288	23	8%
	All Others	225	238	6	6	280	20	7%
230 kV	West	4	4	133	133	403	20	5%
	North	1	1	10	10	386	20	5%
	All Others	657	688	9	11	689	20	3%
345 kV	New York City	269	271	19	19	567	20	4%
	Long Island	270	948	2	24	803	50	6%
	All Others	35	130	5	9	1331	44	3%

The table shows that offline GTs were used much more frequently to manage congestion on the transmission facilities on Long Island than in other regions in 2023. Therefore, Figure A-101 focuses on examining the price effects of offline GTs on transmission constraints on Long Island, grouped as: (a) the 345 kV transmission circuits from upstate to Long Island; and (b) the 138 kV transmission constraints within Long Island.

The scatter plots show transmission constraint shadow prices on the y-axis and transmission violations on the x-axis. For one particular constraint shadow price, the blue diamond represents the transmission violation recognized by RTD, while the red diamond represents the violation after removing the relief from offline GTs.

Figure A-101: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2023



K. Market Operations and Prices on High Load Days

NYISO experienced three heat waves in the summer of 2023 (July 5-7 and 26-28 and September 5-8), while load exceeded 30 GW on just one day (September 6). The NYISO did not activate mandatory EDRP/SCR responses during these periods. Nonetheless, NYISO SREed resources for statewide capacity needs and local TOs activated various amounts of utility demand response resources on several days.[338] This subsection evaluates prices under these market conditions.

Figure A-102 -Figure A-104: Market Operations and Prices on High Load Days

Figure A-102 to Figure A-104 summarize market outcomes on select high load days when SRE commitments were made by the NYISO to maintain adequate reserves and/or DR was deployed by NYISO and/or TOs. Both figures report the following quantities in each interval of afternoon peak hours (HB 10 - HB 22) for NYCA:

- Available capacity from non-SRE resources – Includes three categories of unloaded capacity on online units and offline peaking units up to the Upper Operating Limit:
  - 30-minute reserves that are scheduled by the market model;
  - 30-minute reserves that are available but are not scheduled by the market model; and
  - Additional capacity that is only available beyond 30 minutes of ramping.
- Schedules from SRE resources – This includes scheduled energy and total 30-minute reserves from SRE resources.

338 See presentation "NYISO Summer 2023 Hot Weather Operations" by Aaron Markham at the October 11 OC meeting for more details.

- Constraint shadow prices on the NYCA 30-minute reserve requirement.

In both figures, the solid black lines represent the NYCA 30-minute reserves requirement, adjusted for SCR/EDRP calls when applicable, which is 2620 MW plus estimated SCR/EDRP deployment. The dashed black lines show the quantity equal to the amount of deployed utility DR plus the SCR/EDRP-adjusted NYCA 30-minute reserves requirement. The solid purple lines show the system surplus capacity that would be available had the SRE commitments not been made, which is estimated as the amount of available capacity from non-SRE resources minus energy schedules on SRE resources. Therefore, the difference between the solid black line and the solid purple line indicates the size of the shortage without the SRE commitments; and the difference between the dashed black line and the solid purple line indicates the size of the shortage without SRE commitments and utility DR deployments.

Figure A-102: SRE Commitments and Utility DR Deployment on High Load Days

July 6-7, 2023

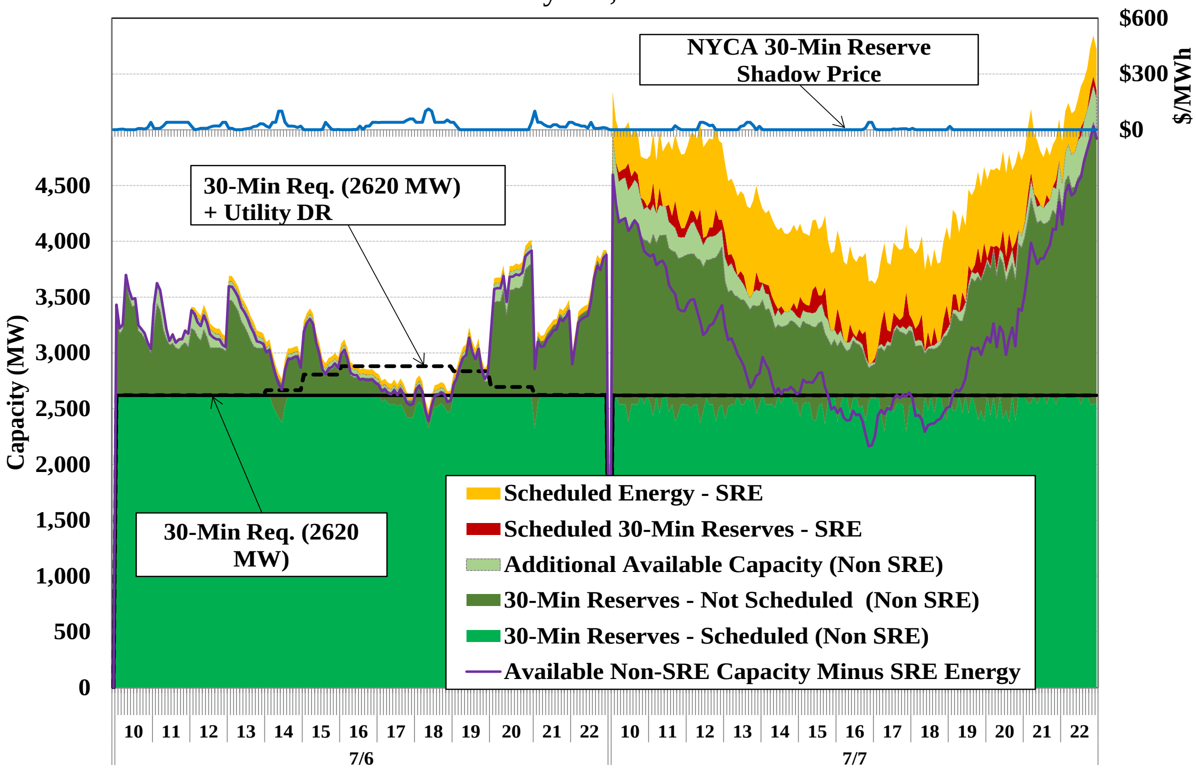


Figure A-103: SRE Commitments and Utility DR Deployment on High Load Days
July 27-28, 2023

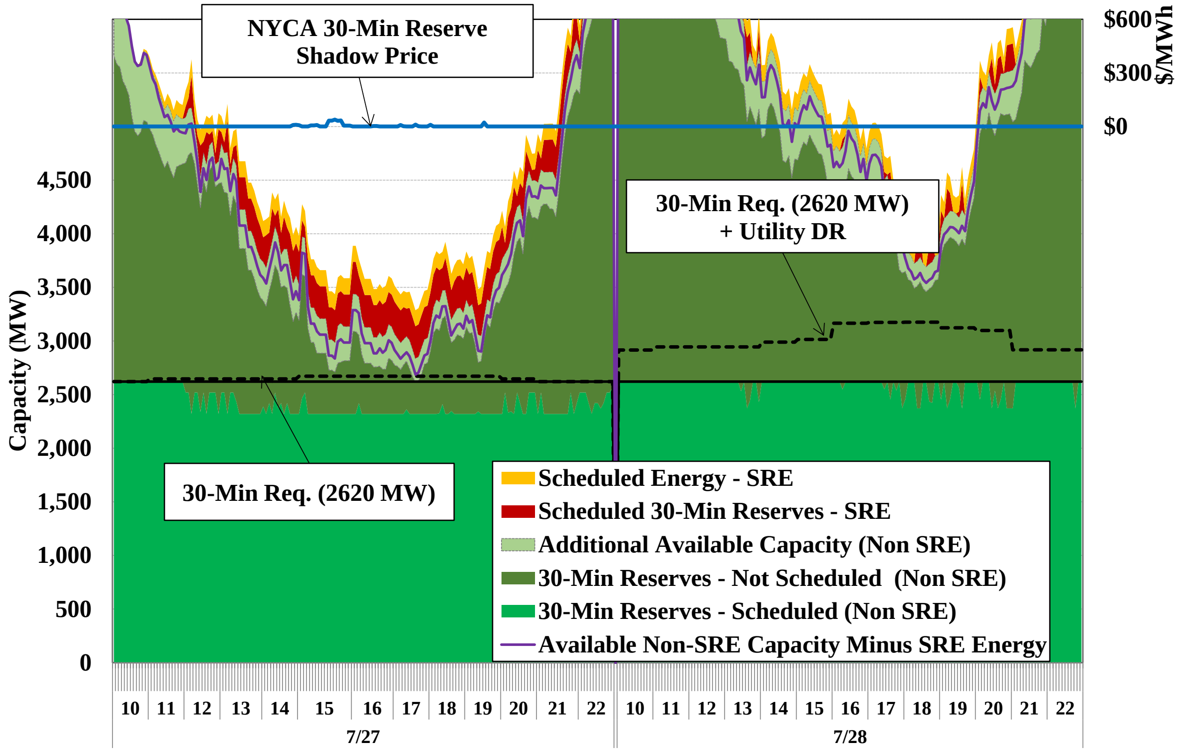
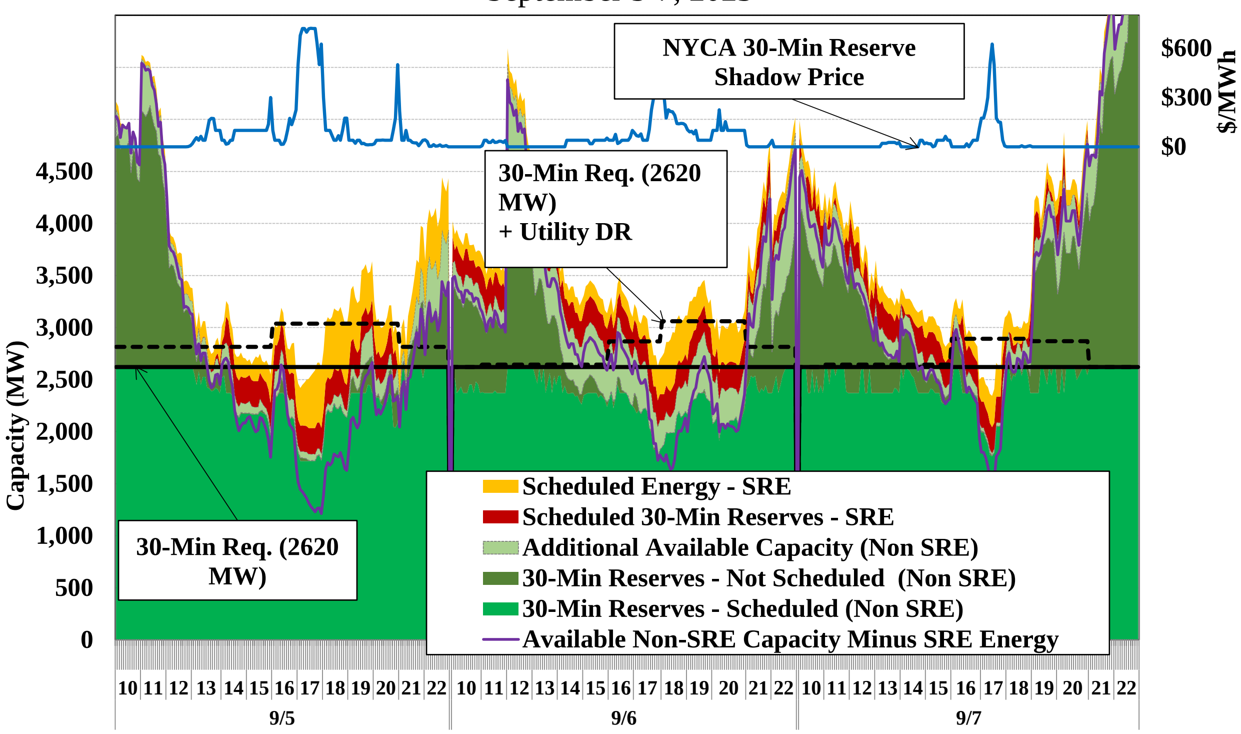


Figure A-104: SRE Commitments and Utility DR Deployment on High Load Days
September 5-7, 2023



L. 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-105: 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.

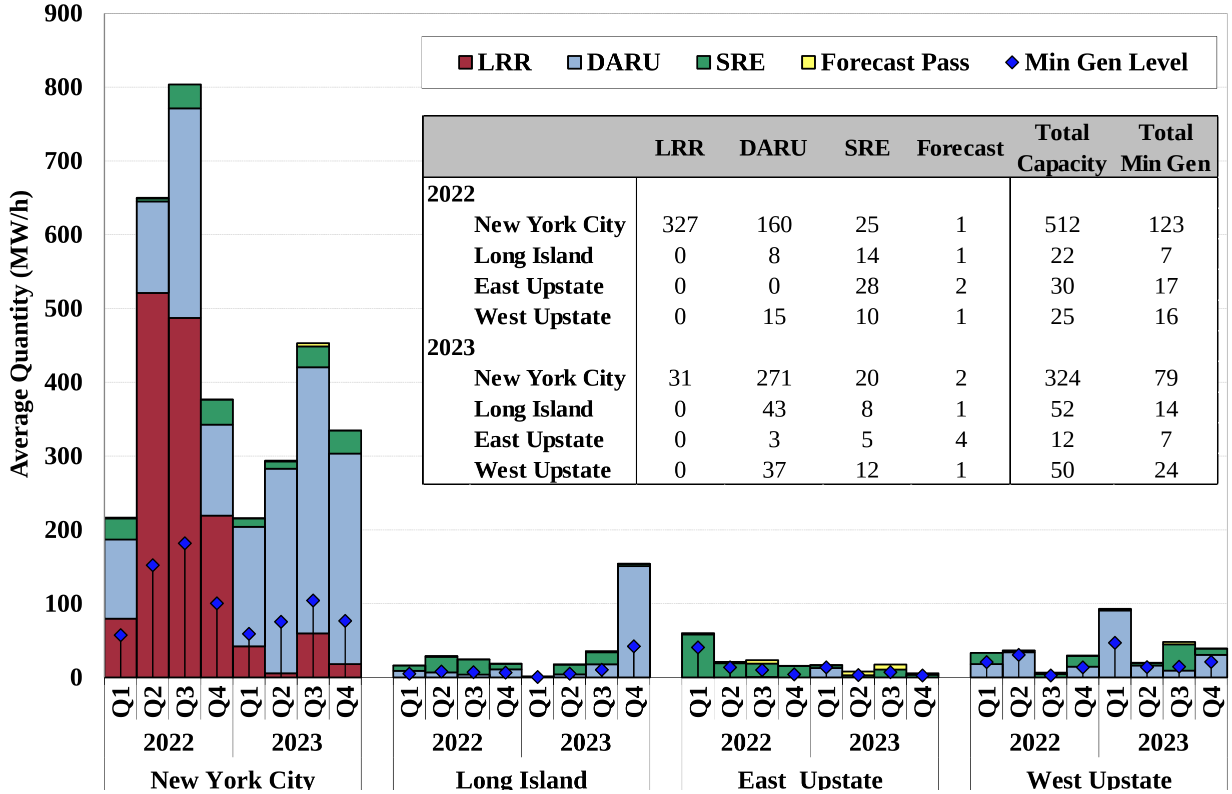
To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected outside the economic evaluation of SCUC. However, to commit units efficiently, SCUC must have accurate assumptions regarding the needs in each local reliability area.

Figure A-105 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 2022 and 2023. 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 2022 and 2023 on an annual basis.

Figure A-105: Supplemental Commitment for Reliability in New York

By Category and Region, 2022 – 2023



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2022						
New York City	327	160	25	1	512	123
Long Island	0	8	14	1	22	7
East Upstate	0	0	28	2	30	17
West Upstate	0	15	10	1	25	16
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

Figure A-106 & Figure A-107: 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-105). 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-106 examines Forecast Pass commitments. The x-axis shows all days when Forecast Pass commitments occurred in 2023. 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 2023 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.

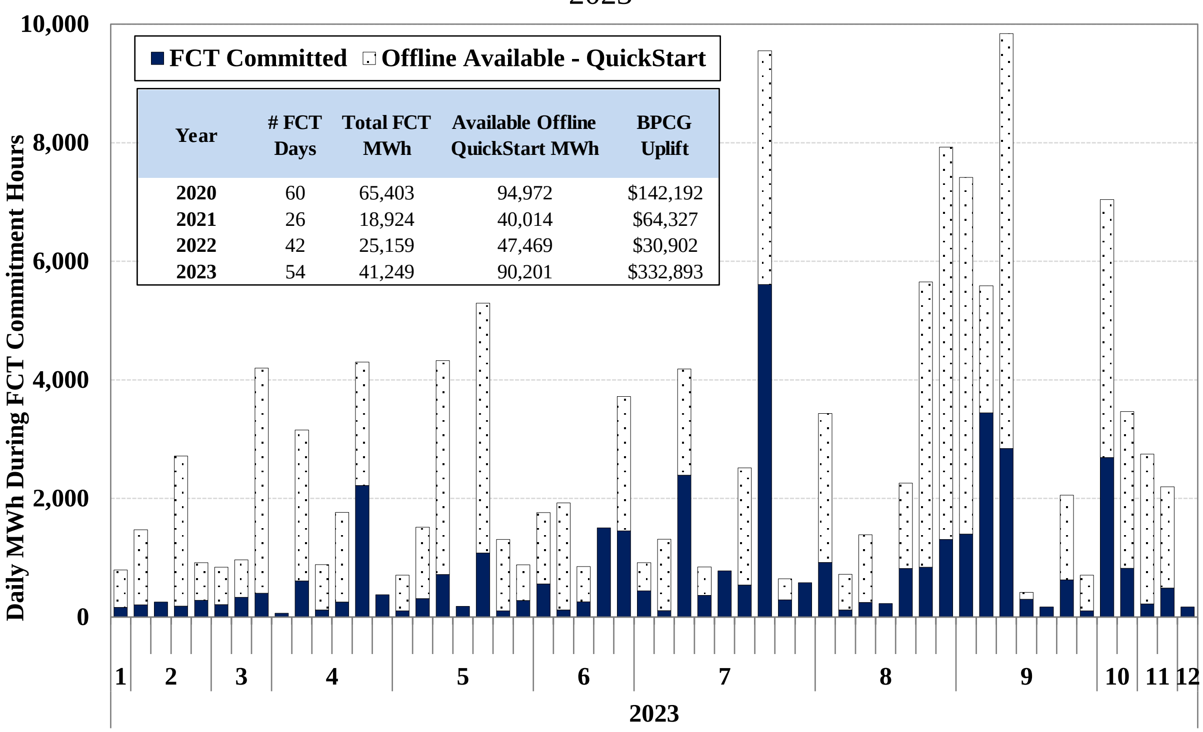
Figure A-107 compares the FCT commitment with forecast physical energy needs in the day-ahead market in 2023, summarizing the following quantities on a daily basis:

- *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-106: Forecast-Pass Commitment

2023



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

Figure A-107: FCT Commitment and DAM Forecast Physical Energy Needs
By Day, 2023

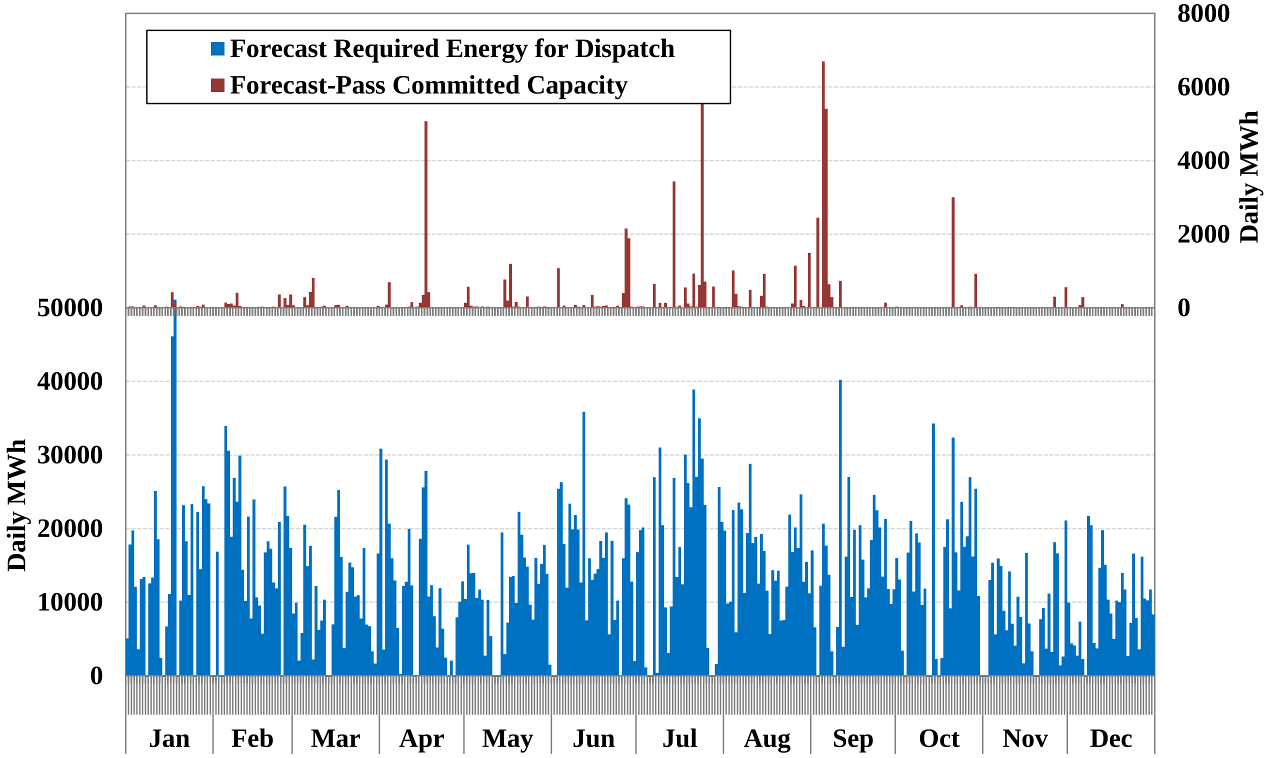


Figure A-108 & Figure A-109 : Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City. Figure A-108 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-108 shows the average capacity committed for reliability by reason and by location in New York City during 2022 and 2023.

Based on our review of the reliability commitment logs and LRR constraint information, each hour of commitment that was flagged as DARU, LRR, or SRE was categorized as committed for one of the following reliability reasons: [339]

- N-1-1-0 – If needed for one or two of the following reasons:
  - Voltage Support – If needed for ARR 26. This occurs when additional resources are needed to maintain voltage without shedding load in an N-1-1-0 scenario.
  - Thermal Support – If needed for ARR 37. Occurs when resources are needed to maintain flows below acceptable levels without shedding load in an N-1-1-0 scenario.

339 A unit is considered committed for a LRR constraint if it would be violated without the unit's capacity.

- Loss of Gas – If needed to protect NYC against a sudden loss of gas supply and no other reason except NOx.[340]
- NOx Only – If only needed for the NOx bubble requirement.[341] When a steam turbine is committed for a NOx bubble, it is because the bubble contains gas turbines that are needed for local reliability, particularly in an N-1-1-0 scenario.

In Figure A-108, for N-1-1-0 constraints, capacity is shown for the load pocket that was secured:

- ERLP - East River Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

Figure A-109 further examines the necessity of DARU commitments in New York City, which accounted for the majority of the reliability commitments during 2023. The figure shows the DARU quantity in stacked bars for each month of 2023 in three distinct categories:

- *Economic MWh*: This 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 MWh*: This represents the total MWh of the initial DARU 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 market, including factors such as load forecast, resource availability, and transmission network conditions.
  - For a particular DARU unit, if it is verified to meet reliability need for at least one hour of the day, all other hours of the day not designated as *Economic* are included in this category.
- *Unverified MWh**:*** This category represents the remaining DARU commitments that do not fit into the other two categories.

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340 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

341 The New York Department of Environmental Conservation ("NYDEC") promulgates Reasonably Available Control Technology ("RACT") emissions standards for NOx and other pollutants, under the federal Clean Air Act. The NYDEC NOx standards for power plants are defined in the Subpart 227-2.4 in the Chapter III of Regulations : "Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx) - Control Requirements", which is available online here. With the retirement of several fast start resources prior to Summer 2023, the NOx Only requirement no longer applies.

Figure A-108: Supplemental Commitment for Reliability in New York City
By Category and Region, 2022 – 2023

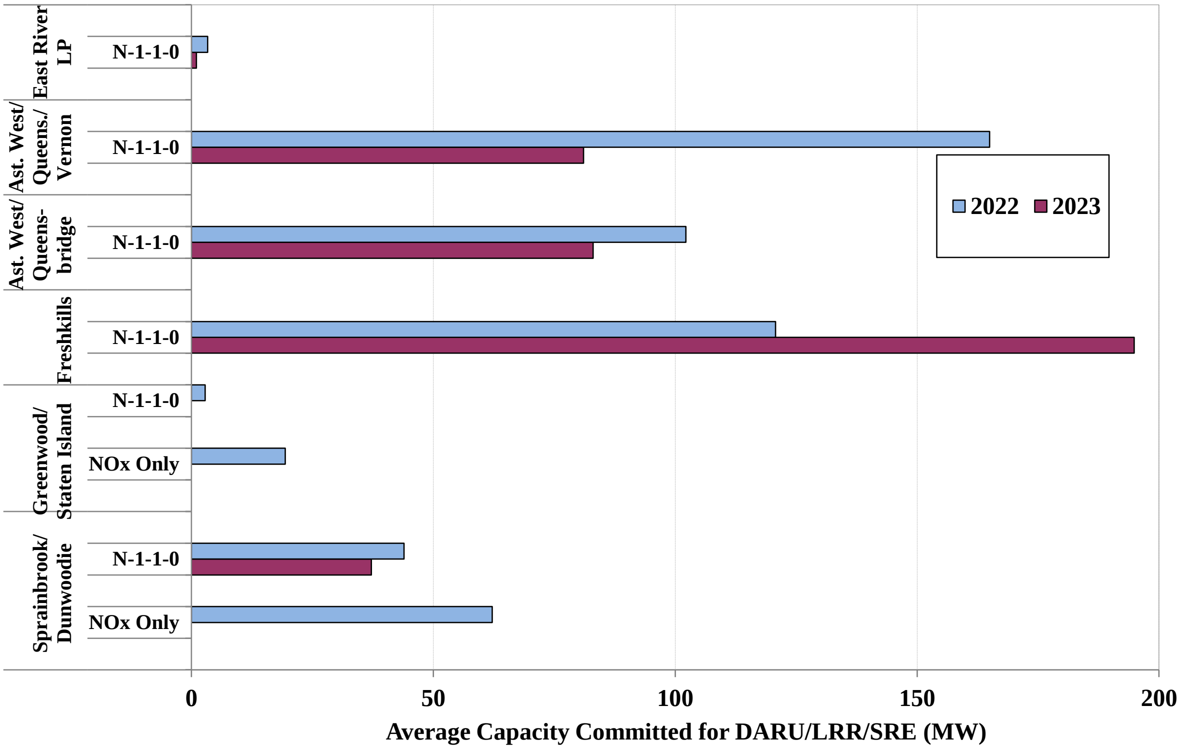
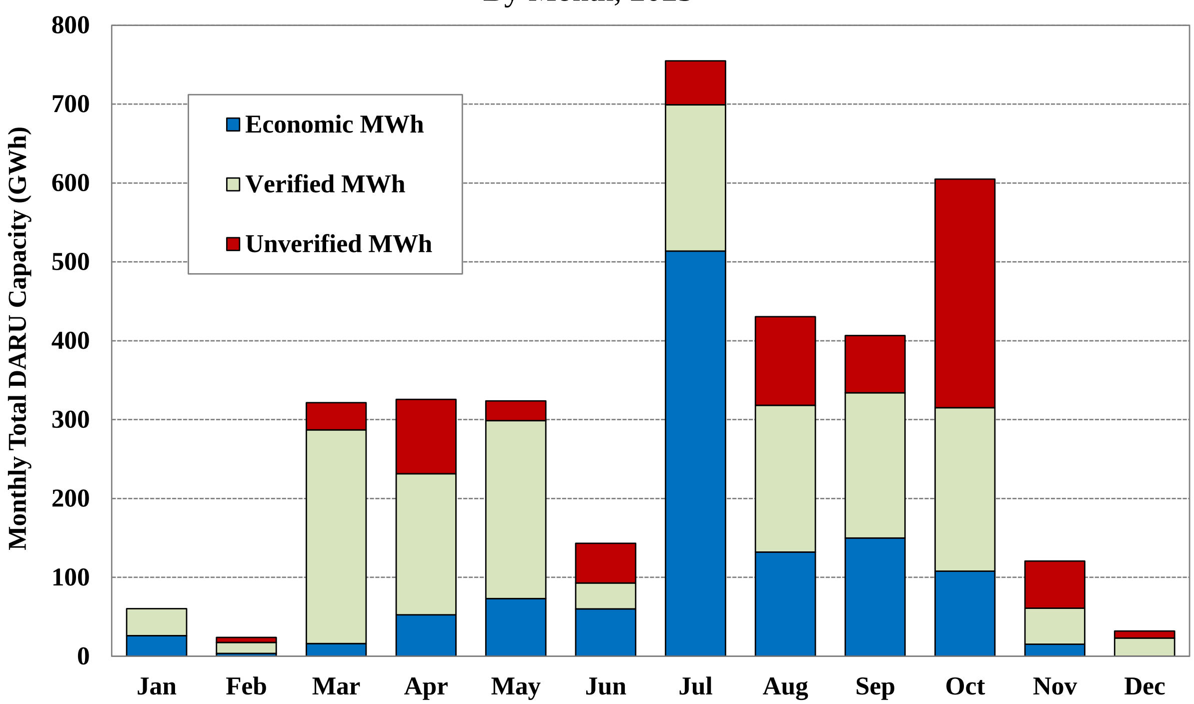


Figure A-109: Evaluation of DARU Commitments by the Local TO in New York City
By Month, 2023



M. 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. Figure A-110 and Figure A-111 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.

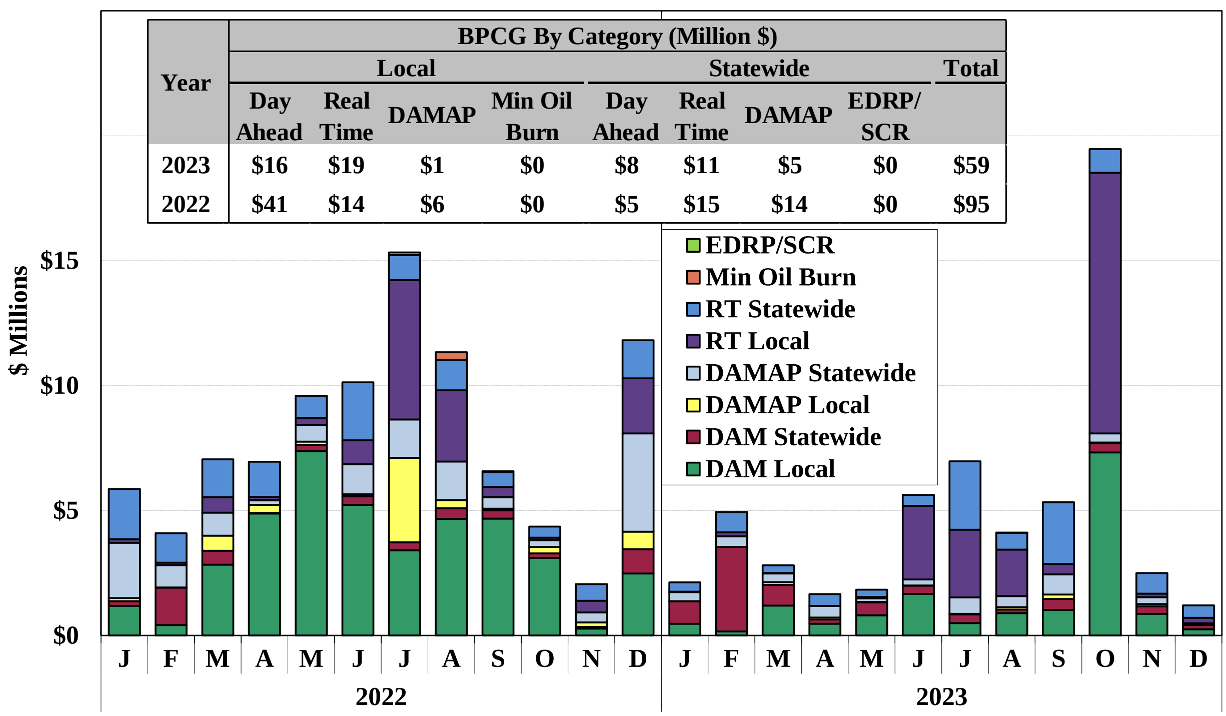
Figure A-110 & Figure A-111: Uplift Costs from Guarantee Payments

Figure A-110 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2022 and 2023. 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-111 shows the seven categories of uplift charges on a quarterly basis in 2022 and 2023 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.

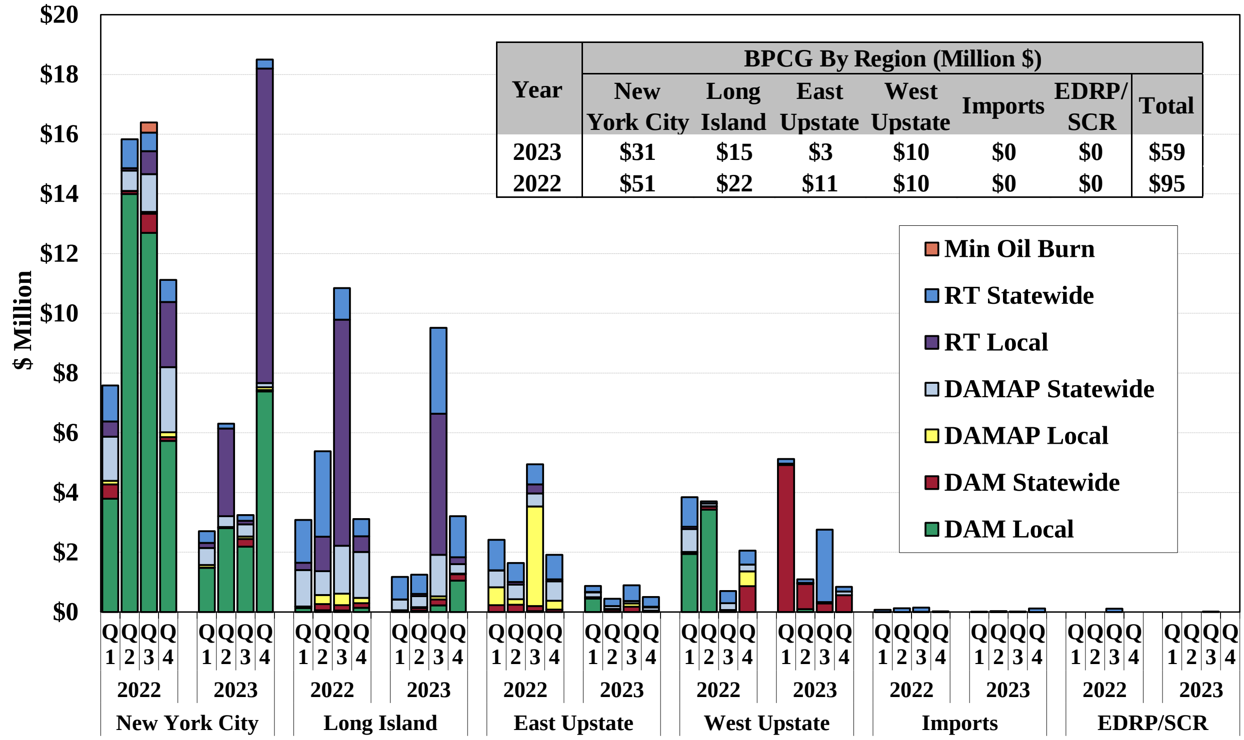
It is also noted that these two tables are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-110: Uplift Costs from Guarantee Payments by Month
2022 – 2023



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2023	$16	$19	$1	$0	$8	$11	$5	$0	$59
2022	$41	$14	$6	$0	$5	$15	$14	$0	$95

Figure A-111: Uplift Costs from Guarantee Payments by Region
2022 – 2023



Year	BPCG By Region (Million $) New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2023	$31	$15	$3	$10	$0	$0	$59
2022	$51	$22	$11	$10	$0	$0	$95

N. Potential Design of Dynamic Reserves for Constrained Areas

This subsection describes a modeling approach with which locational reserve requirements and associated price signals could be dynamically determined based on load, transmission capability, and online generation. This modeling approach is described for an import-constrained area, such as load pockets in New York City, where locational reserve requirements are developed to satisfy local N-1, N-1-1, and N-1-1-0 reliability criteria. But we identify five examples in Recommendation 2015-16 where this modeling approach would provide significant benefit.

The NYISO has developed an excellent market design concept for modeling dynamic reserves constraints in the 2023 *Dynamic Reserves* Market Project for systemwide, N-1, and N-1-1 constraints. The NYISO's formulation models locational marginal pricing for operating reserves and incorporates many elements similar to what is laid out in this subsection.[342]

General Mathematical Problem Formulation for Dynamic Reserves

We first describe the general problem formulation when local (N-1, N-1-1, and N-1-1-0) reserve requirements are set "dynamically." The reserve requirement formulation should be consistent with reliability criteria. Based on NYSRC reliability rules, the general modeling of reserve requirements for a load pocket in New York City may take the following form:

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342 For a detailed description of the NYISO approach, see *Dynamic Reserves Market Design*, presented at the Business Issues Committee, December 13, 2023.

- $\sum$(GenMW_i + Res10MW_i) >= CapReq_10Min (1)
- $\sum$(GenMW_i + Res10MW_i + Res30MW_i) >= CapReq_30Min (2)
- $\sum$(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) >= CapReq_60Min (3)

Where "i" represents each qualified generator inside the load pocket, GenMW is the energy schedule, and Res10MW, Res30MW, and Res60MW are 10-minute, 30-minute, and 60-minute reserves schedules.

- CapReq_10Min = Load Pocket Load Forecast – N-1 Post-Contingency LTE Capability
- CapReq_30Min = Load Pocket Load Forecast – N-1-1 Post-Contingency LTE Capability
- CapReq_60Min = Load Pocket Load Forecast – N-1-1-0 Post-Contingency NORM Capability

For a Line N-1 constraint,

- N-1 Post-Contingency LTE Cap = Import Total LTE Rating – Line 1 LTE Rating (1.1)

For a Gen N-1 constraint,

- N-1 Post-Contingency LTE Cap = Import Total LTE Rating (1.2)

For a Line-Line N-1-1 constraint,

- N-1-1 Post-Contingency LTE Cap =

  Import Total LTE Rating – Line 1 LTE Rating – Line 2 LTE Rating (2.1)
- N-1-1-0 Post-Contingency NORM Cap =

  Import Total NORM Rating – Line 1 NORM Rating – Line 2 NORM Rating (3.1)

For a Line-Gen N-1-1 constraint,

- N-1-1 Post-contingency LTE Cap =

  Import Total LTE Rating – Line 1 LTE Rating (2.2)
- N-1-1-0 Post-Contingency NORM Cap =

  Import Total NORM Rating – Line 1 NORM Rating (3.2)

Where Line 1 and Line 2 refer to the first and second largest Line contingencies.

The largest generator in the load pocket is excluded from the left-hand sides of Equations (1.2), (2.2), and (3.2) for Gen N-1 and Line-Gen N-1-1 constraints. Furthermore, when these are modeled in the day-ahead market, virtual supply and other non-physical sales are excluded from the left-hand sides of the constraints listed above.

The Constraint (3) reflects the commitment requirement based on the N-1-1-0 operating criteria in New York City. Although this requirement is currently modeled via the LRR constraint in the day-ahead market only, the Constraint (3) should be included in both the day-ahead and real-time markets in the future design to reflect the consistent need. A 60-minute product in real-time will likely incent units to be more flexible in real-time as well.

Pricing Logic for Dynamic Reserve Formulation

The following discusses how the shadow prices for dynamic reserve requirements are used in setting reserve clearing prices and energy LBMPs.

Combine all equations and rewrite the constraints for a Load Pocket, LP^k, as follows:

- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE$ (1.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i) \geq \ Load\ Forecast - Total\ LTE$ (1.2)
- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i + Res30MW_i) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE + Line\ 2\ LTE$ (2.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i + Res30MW_i\ ) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE$ (2.2)
- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq \ Load\ Forecast - Total\ NORM + Line\ 1\ NORM + Line\ 2\ NORM$ (3.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i + Res30MW_i + \ Res60MW_i\ ) \geq \ Load\ Forecast - Total\ NORM + Line\ 1\ NORM$ (3.2)

Where LG denotes the largest online generator in the Load Pocket LP^k.

Assume that $SP_{1.1}, SP_{1.2}, SP_{2.1}, SP_{2.2}, SP_{3.1}, SP_{3.2}$ are the constraint shadow prices for these constraints, respectively, then:

- $Reserve\ Price\ Adder_{10min} = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{1.1} + SP_{2.1} + SP_{3.1}, i = LG & \end{cases}$
- $Reserve\ Price\ Adder_{30min} = \begin{cases} SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{2.1} + SP_{3.1}, i = LG & \end{cases}$
- $Reserve\ Price\ Adder_{60min} = \begin{cases} SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{3.1}, i = LG & \end{cases}$
- $LBMP\ Adder = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{1.1} + SP_{2.1} + SP_{3.1}, i = LG & \end{cases}$

These price adders will be reflected in final energy and reserve prices for individual resources. This pricing logic has the following implications:

- Besides the difference in loss and congestion, energy prices at different locations will also reflect different values for satisfying local reliability needs, which are shown by the LBMP adder.

- Energy prices for virtual supply may be lower than energy prices for physical supply (at the same location) in the day-ahead market. This is because the shadow costs of above-mentioned constraints are applied to physical energy only. This market outcome is generally desirable because higher LBMPs for physical energy reflect their additional values for satisfying local reliability needs.

- Energy and reserves prices for the largest generator in the load pocket may be lower than other generators in the load pocket. This is because the shadow costs of the N-1 Generator, and N-1-1 and N-1-1-0 Line-Generator Constraints are applied to all generators in the load pocket except the largest unit. There may be different settlement options to consider (from market incentive perspective) for the largest unit in the load pocket. One way is to pay the largest unit the lower market clearing price. An alternative way is to pay the largest unit the same price (as for other units in the load pocket) but add a charge for extra reserve costs incurred because of the generation contingency.

An Illustrative Example

The following provides a stylized example to illustrate how dynamic reserves requirements would affect reserve clearing prices and LBMPs under typical conditions in a load pocket. It contrasts market outcomes under the current design where local reserve needs are met through out-of-market commitment with outcomes when local reserve requirements are considered.

Description of the Simulated System

As shown in Figure A-112, the example system has two areas, A and B, where B is a load pocket. There are four lines connecting A and B, with their Norm and LTE line ratings labeled in the figure.

Figure A-112: Illustrative Diagram of the example system

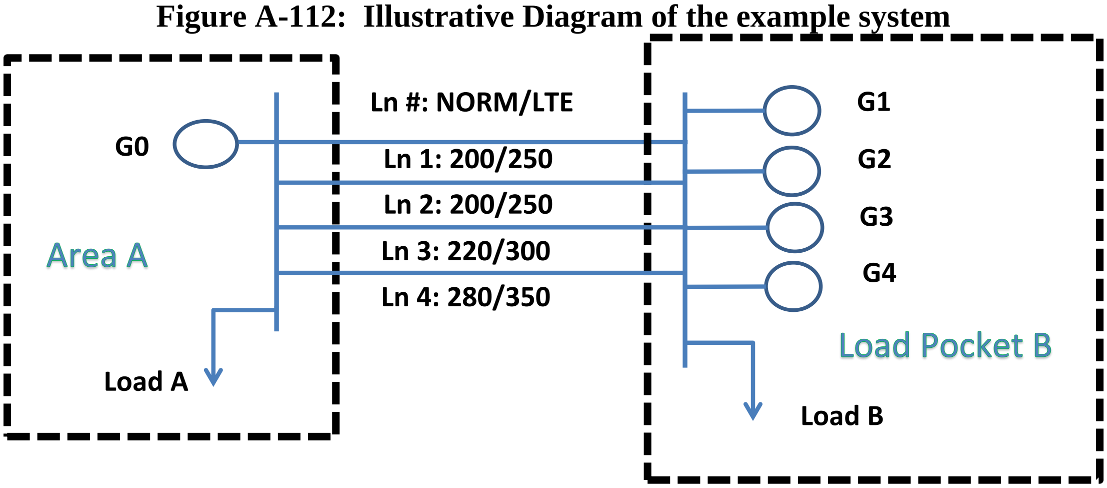

Table A-15 lists assumed physical parameters for the five generators in the example system. G0 represents the aggregation of less expensive generation in Area A, while G1 represents a slow-moving ST in the load pocket, which is also the largest generator in the pocket. G2 and G3 represent two CCs, and G4 represents a Bayonne-type facility that is capable of starting-up in 10 minutes.

Table A-15. Generator Physical Parameters

Generator	MinGen (MW)	UOL (MW)	Ramp Rate (MW/Min)	Fast Start
G0	200	3500	40	N
G1	75	300	3	N
G2	125	210	6	N
G3	120	200	6	N
G4	0	200	20	10Min

The example also assume that:

- 1500 MW of load in Area A
- 1100 MW of load in Load Pocket B
- Fixed reserve requirements are used at the system level, which are:
  - 150 MW of 10-minute spinning reserve requirement;
  - 300 MW of 10-minute total reserve requirement; and
  - 600 MW of 30-minute total reserve requirement.

Constraints (1.1)-(3.2) listed above, referred herein as Dynamic Reserve Constraints, are implemented for the Load Pocket B as follows,

- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i) \geq 300$ (1.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i) \geq -50$ (1.2)
- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i) \geq 600$ (2.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i) \geq 300$ (2.2)
- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq 700$ (3.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq 480$ (3.2)

Table A-16 shows the offer prices for minimum generation, incremental energy, and various reserve products for the five generators. The table also assumes that 100 MW of virtual supply (shown as V1) is placed in the Load Pocket, which only provide energy and do not count toward satisfying reserve requirements.

Table A-16: Generator Bids

Area	Generator	Min Gen	Inc Energy	10-Min Spin	10-Min Non-Spin	30-Min Reserve	60-Min Reserve
A	G0	$20	$20	$1		$0.5	
B	V1		$18				
	G1	$40	$30	$4.5		$3	$2
	G2	$25	$23	$4.75		$4	$3.75
	G3	$24	$22	$5		$3.5	$3
	G4		$40		$5		

Simulated Results Under the Dynamic Reserve Construct

Assuming a lossless system, the optimization produces the following scheduling and pricing outcomes (for energy, 10-minute spinning reserves, 10-minute non-spin reserves, 30-minute operating reserves, and 60-minute reserves) in Table A-17:

Table A-17: Scheduling and Pricing Outcomes with Dynamic Reserve Constraints

Area	Generator	Schedules (MW)					Prices ($/MWh)				
		Energy	10 SP	10 NS	30 OP	60 OP	Energy	10 SP	10 NS	30 OP	60 OP
A	G0	2015	230		255		$20	$1	$1	$0.5	$0
B	V1	100					$20				
	G1	75	0		45	100	$22.5	$3.5	$3.5	$3	$2
	G2	210	0		0	0	$24	$5	$5	$4.5	$3.5
	G3	200	0		0	0	$24	$5	$5	$4.5	$3.5
	G4	0		70			$24	$5	$5	$4.5	$3.5

These pricing outcomes are derived from the following binding constraints:

- Power balance constraint, with a shadow cost of $20/MWh;
- Systemwide 10-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- Systemwide 30-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- The constraint (2,1), with a shadow cost of $0.5/MWh;

- The constraint (3.1), with a shadow cost of \$2.0/MWh; and
- The constraint (3.2), with a shadow cost of \$1.5/MWh;

Accordingly, we have the following adders for energy and reserves for generators in the Load Pocket, as defined earlier,

- $Reserve\ Price\ Adder_{10min} = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$
- $Reserve\ Price\ Adder_{30min} = \begin{cases} SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$
- $Reserve\ Price\ Adder_{60min} = \begin{cases} SP_{3.1} + SP_{3.2} = \$\mathbf{3.5}, & i \in \{2,3,4\} \\ SP_{3.1} = \$\mathbf{2.0}, & i = 1 \end{cases}$
- $LBMP\ Adder = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$

Simulated Results Under the Current Market Construct

To illustrate the difference in scheduling and pricing between the dynamic reserve construct and current market construct, we also simulated this example system using the current market construct that:

- Commits the resources based on the N-1-1-0 requirement in the load pocket; then
- Dispatches and prices resources without explicitly modeling this requirement.

Keeping the same unit commitment but removing the dynamic reserve constraints (1.1)-(3.2), Table A-18 shows the scheduling and pricing outcomes under the current market construct.

Table A-18: Scheduling and Pricing Outcomes without Dynamic Reserve Constraints

Area	Generator	Schedules (MW)					Prices (\$/MWh)				
		Energy	10 SP	10 NS	30 OP	60 OP	Energy	10 SP	10 NS	30 OP	60 OP
A	G0	2180	300		300		\$20	\$1	\$1	\$0.5	
B	V1	100					\$20				
	G1	75	0		0	0	\$20	\$1	\$1	\$0.5	
	G2	125	0		0	0	\$20	\$1	\$1	\$0.5	
	G3	120	0		0	0	\$20	\$1	\$1	\$0.5	
	G4	0		0			\$20	\$1	\$1	\$0.5	

Unlike under the dynamic reserve construct, generators in the load pocket are all dispatched at their MinGen levels and have no reserve schedules under the current market construct. The pricing outcomes are derived from the following binding constraints:

- Power balance constraint, with a shadow cost of $20/MWh;
- Systemwide 10-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- Systemwide 30-minute total reserve requirement, with a shadow cost of $0.5/MWh.

Discussion of Simulation Results

These simulation results demonstrate that, under the dynamic reserve construct,

- The market may schedule more expensive generators to provide energy inside the load pocket (e.g., G3 from 120 to 200 MW) and schedule less from inexpensive generation outside the load pocket (e.g., G0 from 2180 to 2015 MW) to hold reserves on the interface for the load pocket when it is economic to do so.
- Absent transmission congestion (no congestion in this example), price separation still exists between generators outside and inside the load pocket. Higher LBMPs in the load pocket ($22.5 - $24/MWh in the pocket vs. $20/MWh outside of the pocket) reflect additional values for satisfying local reliability needs.
- Energy prices for virtual supply may be lower than energy prices for physical supply in the load pocket ($20/MWh vs. $22.5-$24/MWh) as virtual supply only provides energy and does not satisfy local reliability needs.
- Energy and reserves prices for the largest generator in the load pocket may be lower than other generators in the load pocket ($22.5/MWh vs $24/MWh) because it is less valuable to satisfy local reliability needs as it is part of contingencies for deriving the reserve needs. However, instead of paying the largest unit different prices, an alternative way is to pay the largest unit the same prices (as for other units in the load pocket), but add a charge for extra reserve costs incurred because of the generation contingency. The extra reserve cost is calculated as the sum of shadow costs of constraint (1.2), (2.2) and (3.2) times the additional schedules on the largest generator (i.e., energy and reserve schedules of the largest generator Minus energy and reserve schedules of the second largest generator). In this example, the extra reserve cost is $1.5*(220-210) = $15.

O. Potential Design for Compensating Reserve Sellers that Provide Congestion Relief

The NYISO is ordinarily 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 immediately after the contingency. However, the NYISO is sometimes allowed to operate a facility above its LTE if post-contingency actions would be available to quickly reduce flows to

LTE after a contingency.[343] Post-contingency actions include deployment of operating reserves and adjustments to phase-angle regulators. The use of post-contingency actions is important because it allows the NYISO to increase utilization of the transmission system into load centers, thereby reducing production costs and pollution in the load center.

The value of rules that allow congestion to be managed with reserves rather than actual generation dispatch becomes apparent when reserves and other post-contingency actions become unavailable. In such cases, transfer capability is reduced, requiring more generation in the load pocket to manage congestion. This can happen during severe cold weather conditions when constraints on the gas pipeline system in New York City limit the fuel supply of some units that usually provide operating reserves, reducing the import capability of the transmission system. In spite of providing valuable services especially during tight system conditions, these operating reserve suppliers are not currently compensated for helping manage congestion. This subsection describes a potential solution for the market to efficiently compensate these operating reserve providers.

The following equation describes a typical N-1 transmission constraint, k, that is used in the day-ahead and real-time market:

- $\sum_i \left(SF_i^k * Gen_i \right) \leq Limit_{N-1}^k$ (1)

For each relevant generator i for the constraint k, SF_i^k is the shift factor and Gen_i is the energy schedule. $Limit_{N-1}^k$ is the N-1 limit for the constraint, which could be set above its LTE rating because of the anticipated deployment of reserves post-contingency.

When operators estimate the additional up room from the LTE, available operating reserves that could help reduce post-contingency flows within 10 minutes are typically considered. As long as the total relief from 10-minute reserves is greater than or equal to the difference between $Limit_{N-1}^k$ and LTE^k, the post-contingency flows after the reserve deployment will be managed below the LTE. This translates to the following equation,

- $\sum_i [Min\left(0, SF_i^k\right) * 10MinReserve_i] \leq LTE^k - Limit_{N-1}^k$ (2)

When Equation (2) is modeled together with Equation (1), the shadow price of Equation (2) will reveal the economic value of 10-minute reserve providers that help manage congestion. Therefore, the market could compensate these reserve suppliers based on this shadow price, which will be in addition to other compensation that these reserve suppliers receive for satisfying systemwide and local reserve requirements.

The concepts presented in this subsection are comparable to the NYISO's proposal for N-1 constraint modeling in the 2023 *Dynamic Reserves* Market Project.[344]

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343 See *NYISO Transmission and Dispatching Operations Manual*, Section 2.3.2.

344 For a detailed description of the NYISO approach, see *Dynamic Reserves Market Design*, presented at the Business Issues Committee, December 13, 2023.

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 provides economic signals that supplement the signals 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. The NYISO uses the IRM in conjunction with the annual peak load forecast to calculate the Installed Capacity ("ICAP") requirement for NYCA.[345] The 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.[346]

Since the 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 the NYISO.

The NYISO conducts three UCAP auctions: a forward strip auction where capacity is transacted in six-month blocks for the upcoming capability period, a monthly forward auction where capacity 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. The capacity demand curves are used to determine the clearing prices and quantities purchased in each locality in each monthly UCAP spot auction.[347] 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).

345 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 19.6 percent in the most recent Capability Year (i.e., the period from May 2022 to April 2023). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

346 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 99.5 percent from May 2022 to April 2023 and 105.2 percent from May 2023 to April 2024. The New York City LCR was 81.2 percent from May 2022 to April 2023 and 81.7 percent from May 2023 to April 2024. The LCR for the G-J Locality was set at 89.2 percent from May 2022 to April 2023 and 85.4 percent from May 2023 to April 2024. These are set in the annual Locational Minimum Installed Capacity Requirements Study, which may be found here.

347 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.

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 capacity market Locality is defined as a straight line through the following two points:[348]

- 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".
- $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, the NYISO and its consultants establish the parameters of the capacity demand curves through a study that includes a review of the selection, costs, and revenues of the peaking technology. Each year, the 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. Distinct requirements, demand curves, and clearing prices are set in each Locality, although 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);
- Description of Potomac's Resource Adequacy Model and associated input assumptions for analyses in this report (sub-section E);
- Analyses of the efficiency of the capacity market locational signals (sub-section F);
- Quantitative examples of CCP Factor (sub-section G) Financial Capacity Transfer Rights ("FCTRs") proposals (sub-section H); and
- Methods for assessing marginal capacity value by resource category (sub-section I).

348 The demand curves have maximum price levels that apply when UCAP procured falls well below the requirement. The demand curves can be found on NYISO's installed capacity market webpage, here.

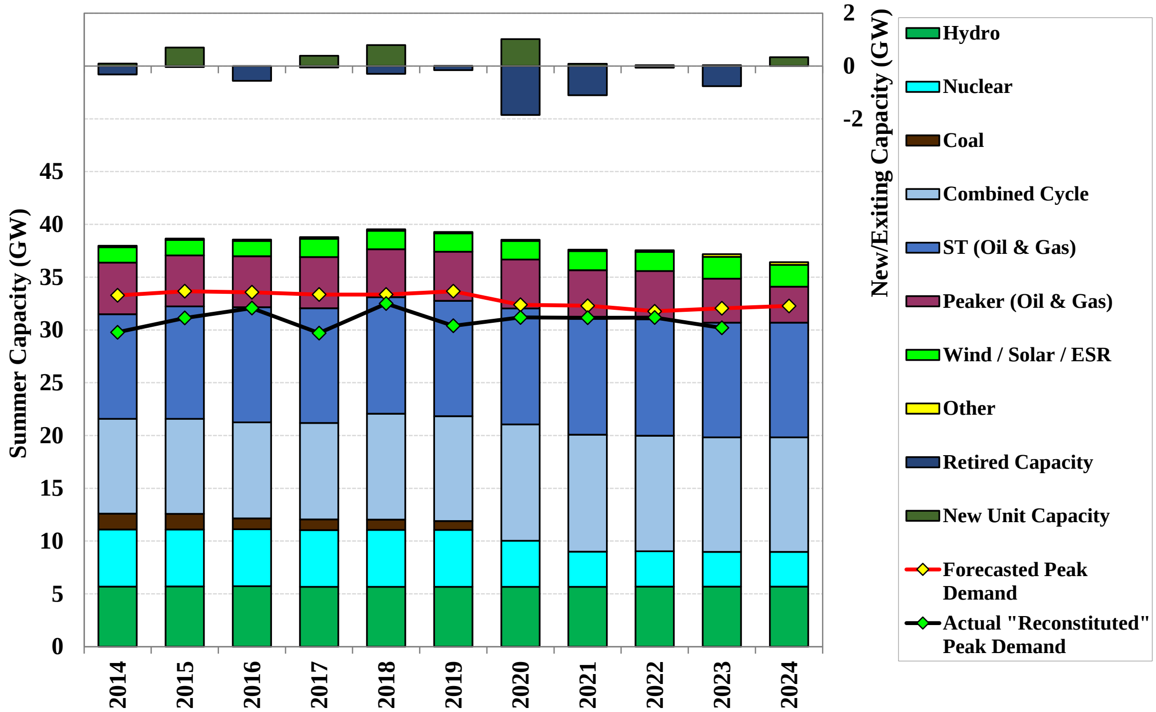
A. Installed Capacity of Generators in NYCA

Figure A-113 - Figure A-114: Installed Summer Capacity and Forecasted Peak Demand

The next two figures show the amount of installed capacity in NYCA and various regions by fuel and technology type. The mix of resources has shifted 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 almost entirely dependent on fossil-fueled capacity with virtually all renewable, hydro, and nuclear resources in upstate regions.

The bottom panel of Figure A-113 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.[349, 350] The top panel of Figure A-113 shows the amount of capacity that entered or exited the market during each year.[351] Generator retirements in the coming years will include units that plan to operate as winter-only resources.

Figure A-113: Installed Summer Capacity of Generation by Prime Mover
2014 – 2024



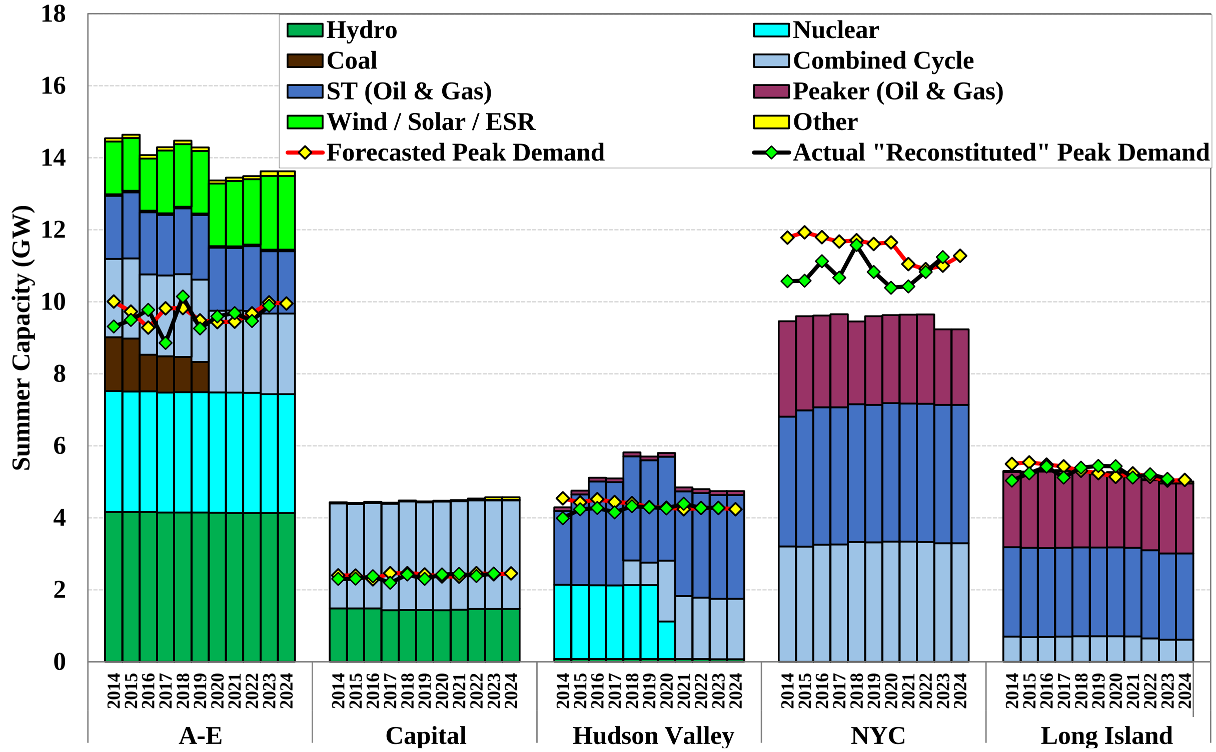
349 Forecasted peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. Capacity is based on the Gold Book and Generator Status Update files.

350 We reconstitute historic coincident and non-coincident peak demand values in Figure A-113 and Figure A-114 to include demand reductions from NYISO and Utility-based activation of DR on peak days. Thus, these numbers differ from published values in years when DR was activated to reduce the peak demand.

351 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-114 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-114: Installed Summer Capacity of Generation by Region and by Prime Mover
2013 – 2023



B. Capacity Imports and Exports

Figure A-115: NYISO Capacity Imports and Exports by Interface

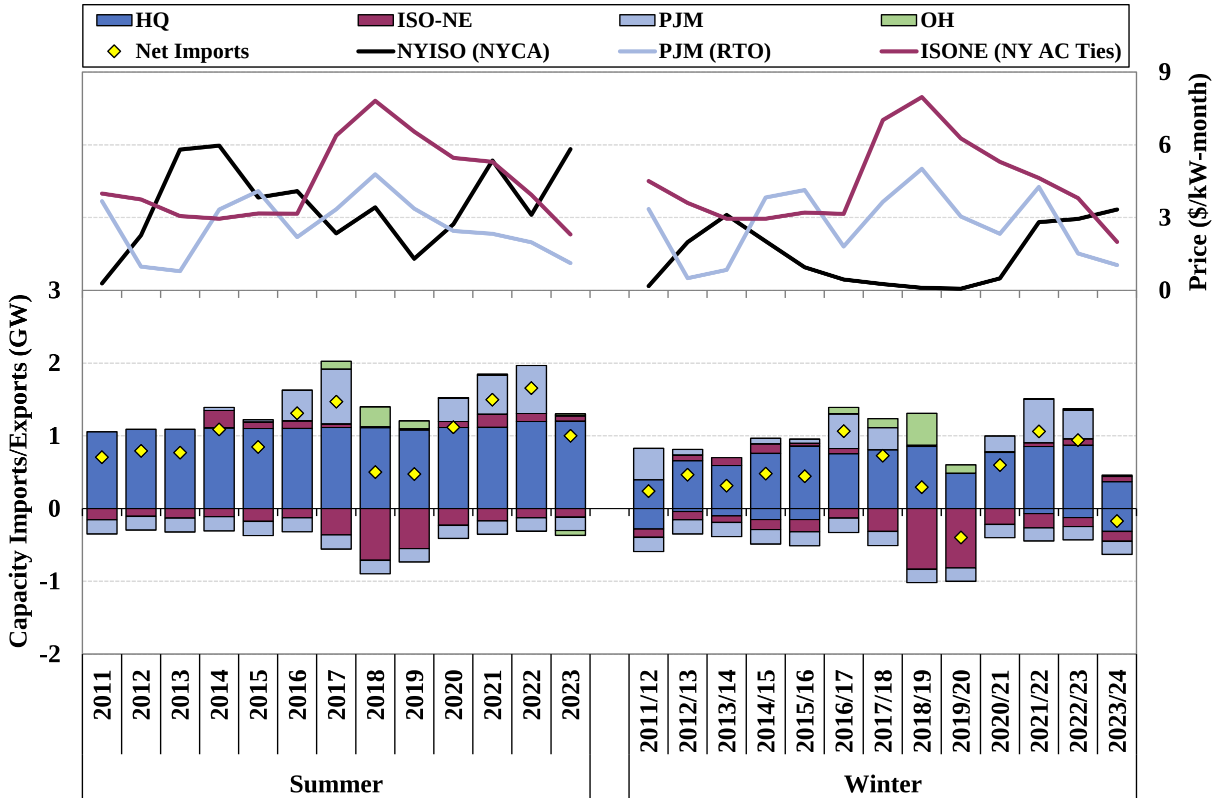
The NYISO procures a portion of its installed capacity from neighboring regions, and some capacity on internal resources is sold to neighboring regions. The difference between the imports and exports serves as incremental (or decremental) capacity in the capacity market and influences the pricing outcomes of each auction.

Figure A-115 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Summer 2011 through Winter 2023/24 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.[352] 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

352 The values for Winter 2023/24, reflect average net imports and average prices through February 2024.

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.

Figure A-115: NYISO Capacity Imports and Exports by Interface
Summer 2011 – Winter 2023/24



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.[353] 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

353 The variables and methodology used to calculate EFORd for a resource can be found here.

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.[354]

Table A-19: Historic Derating Factors by Locality

Table A-19 shows the derating factors the NYISO calculated for each capacity zone from Summer 2019 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-19: Derating Factors by Locality
Summer 2019 – Winter 2023/24

Locality	Summer 2023	Summer 2022	Summer 2021	Summer 2020	Summer 2019	Winter 2023/24	Winter 2022/23	Winter 2021/22	Winter 2020/21	Winter 2019/20
G-I	11.82%	7.63%	5.45%	5.77%	7.15%	10.62%	10.39%	8.41%	3.21%	6.87%
LI	7.29%	6.27%	4.91%	6.91%	6.47%	10.66%	10.31%	7.21%	5.91%	7.96%
NYC	1.64%	3.26%	2.69%	3.51%	4.09%	4.12%	3.41%	2.48%	2.70%	4.42%
A-F	14.48%	14.20%	13.27%	11.78%	12.50%	13.16%	10.70%	11.36%	9.63%	10.26%
NYCA	10.14%	9.78%	8.77%	8.30%	8.79%	10.39%	8.91%	8.40%	6.61%	8.00%

Figure A-116: Unavailable Capacity to RTC & RTD from Various Technologies for 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.[355] The process is similar for each of these unit types, but it takes into consideration certain technology-specific characteristics in fine tuning testing obligations.[356] 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-116 shows the estimated ICAP that was functionally unavailable to the market during peak conditions in the summer of 2023 from fossil generators and nuclear units by the following categories:

- Emergency Capacity – Capacity offered above a generator's normal upper operating limit ("UOLn") that is only available under NYISO Emergency Operations.[357]

354 The Derating Factor used in each six-month capability period for each Locality may be found here.

355 Section 5.12.1.2 of the Tariff establishes the DMNC test obligation on generators.

356 See Section 4.2 of the ICAP Manual.

357 See NYISO Emergency Operations Manual.

- High Air Temperatures – 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.[358]

- Ambient Humidity – the amount of capacity explicitly derated from combined cycle and peaking units that cannot be explained by air temperature conditions.

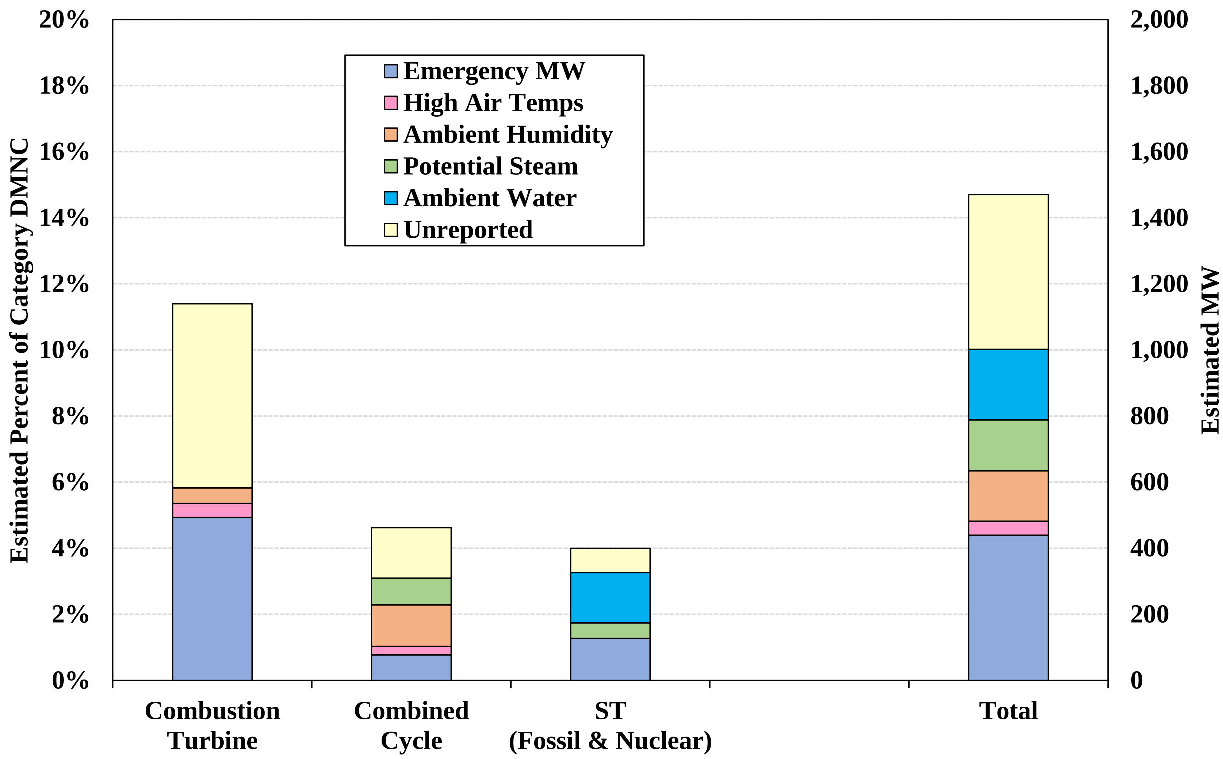
- Potential Steam – the amount of capacity unavailable from cogeneration resources with active host steam load obligations.

- Ambient Water – the amount of capacity explicitly derated from once-through cooled fossil and nuclear steam turbines due to ambient water temperatures and tides.

- Unreported – the amount of capacity observed to be unavailable from generator dragging when dispatched to maximum under peak conditions but without an explicit derate reason reported.

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-116: Functionally Unavailable Capacity from Fossil-Fuel and Nuclear Generators
Summer 2023



358 See NYISO ICAP Manual Attachment M for further details on output factor equations.

Most of the capacity identified in this chart is sold to the market as is any other capacity.[359] The NYISO determined in 2023 that several changes will be implemented beginning with the 2025/26 Capability Year 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.[360]

These changes should improve capacity accreditation, though the impact may be muted for the ambient water temperature conditions. First, water temperatures tend to steadily rise over the peak summer. Temperatures in early-July are predictably lower than those 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. Second, 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 tides 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 of a resource's capability. Therefore, we have recommended 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.

Figure A-117: Incremental Forced Outage Rate of Steam Turbines at High Output Levels

The EFORd values calculated by NYISO may understate the probability of forced outage when a unit is operating close to its maximum capability. Figure A-117 shows the incremental forced outage rate of steam turbines when operating at above 95 percent of DMNC during the summer capability period. A high incremental forced outage rate of this upper output range suggests that operating close to maximum capability increases the probability of experiencing a forced outage or derate on the unit.

Figure A-117 uses data from six summer capability periods (2018-2023). We calculated each unit's EFORd over this period utilizing the IEEE 762-2006 methodologies. We then calculated an Equivalent Forced Outage Rate (EFOR) for each unit considering only hours meeting the following conditions: (1) the unit operated at above 95 percent of its DMNC, or (2) the unit was

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359 Section 5.12.1.5 of the Market Services Tariff carves out that the same Unforced Capacity cannot be sold to more than one buyer at the same time. Situations where a cogeneration resource's capability is sold as steam to a host load do not require rule changes to address the concerns raised in this report

360 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 better enable offering and scheduling of those components.

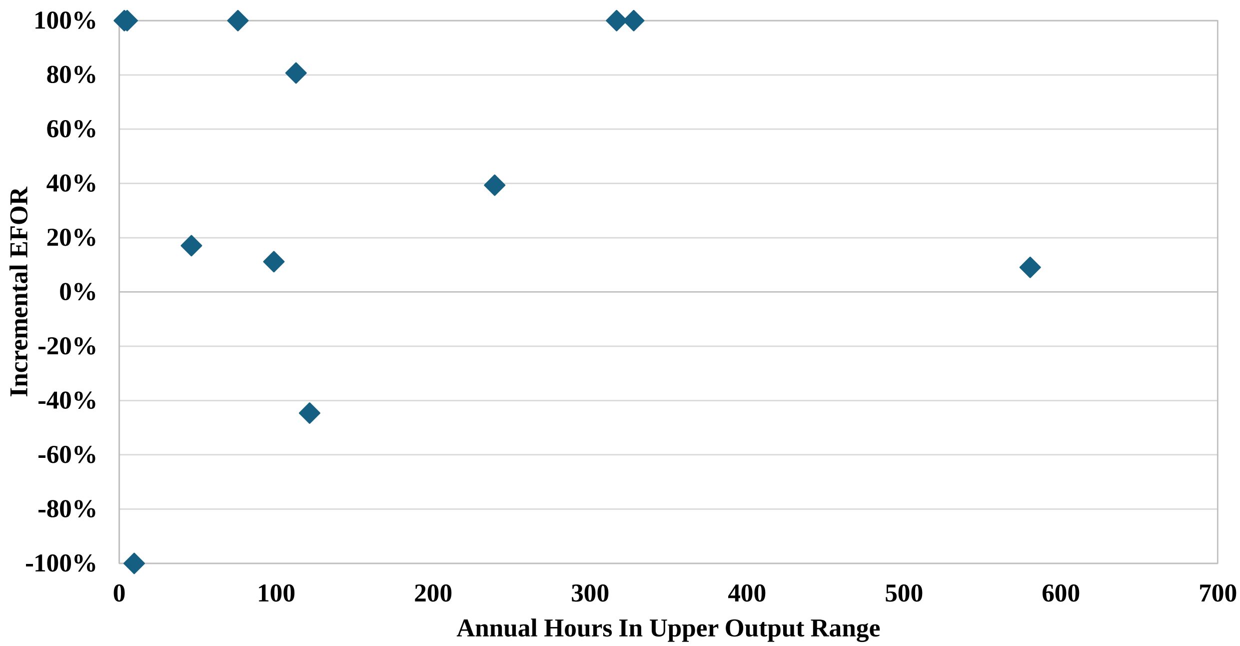
experiencing a forced outage or derate that began within three hours of operating or attempting to operate above 95 percent of DMNC. The Incremental EFOR is calculated as: ((Upper Range EFOR – EFORd) / 0.05). This metric indicates the expected unavailability of the top 5 percent of the unit's capability, considering the increased likelihood of tripping the entire unit.

A positive Incremental EFORd indicates that operating at high output range raises the likelihood of an outage or derate. An Incremental EFOR of 100 percent or greater suggests that the expected value of the upper output range is zero or negative because operating in that range reduces the expected output of the entire unit (considering the probability of forced outage) by more than 5 percent. Figure A-117 suggests that for many steam units, the top 5 percent of output has no incremental benefit from an expected value standpoint. Incremental EFORd in this figure was limited to 100 percent if a higher number would be calculated.

Our analysis excluded behind-the-meter generation units and units with zero hours meeting our criteria to calculate an upper-range EFOR. Also, units with emergency ranges are excluded because they do not have run hours in the upper range outside of DMNC test conditions.

Figure A-117: Incremental Forced Outage Rate of Steam Turbines at High Output Levels

Summer Capability Periods 2018 - 2023



D. Capacity Market Results

Figure A-118 – Figure A-121: Capacity Sales and Prices

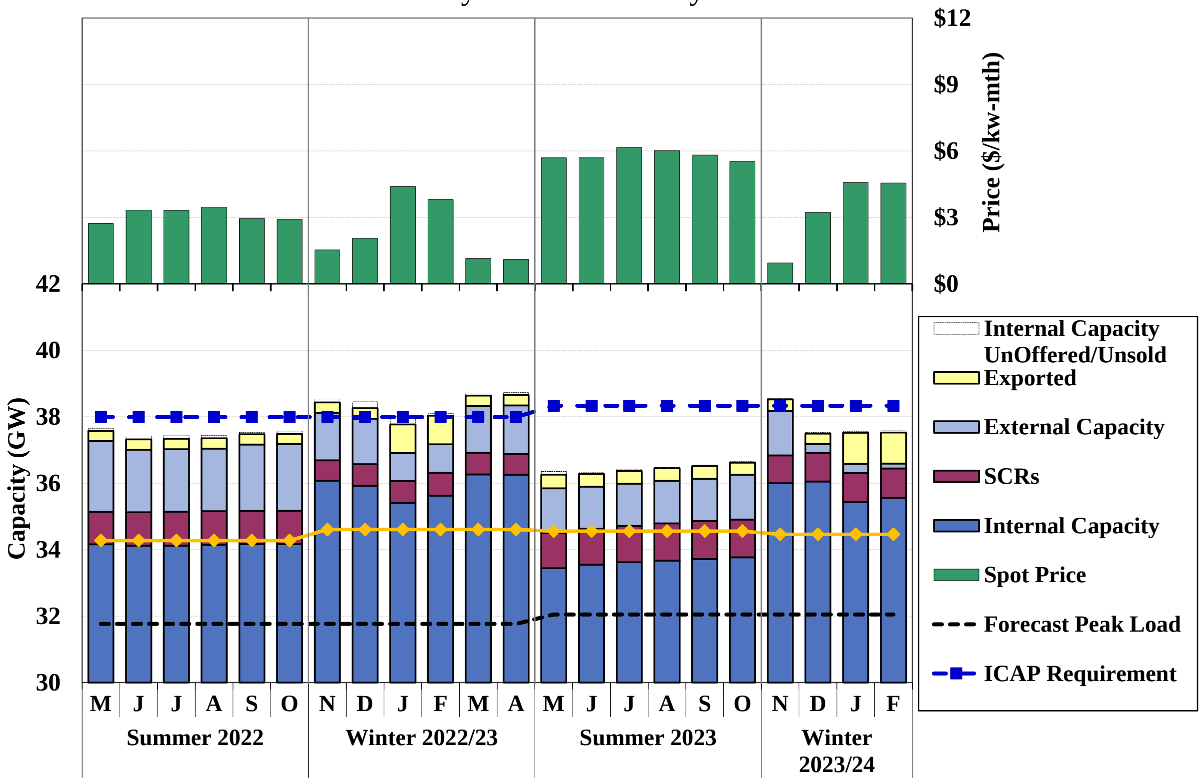
Figure A-118 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs") and sales from

SCRs.[361] 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 examined period, the figure also shows the forecasted peak load and the ICAP requirements.

Figure A-119 to Figure A-121 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-118 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

Figure A-118: UCAP Sales and Prices in NYCA
May 2022 to February 2024



361 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-119: UCAP Sales and Prices in New York City
May 2022 to February 2024

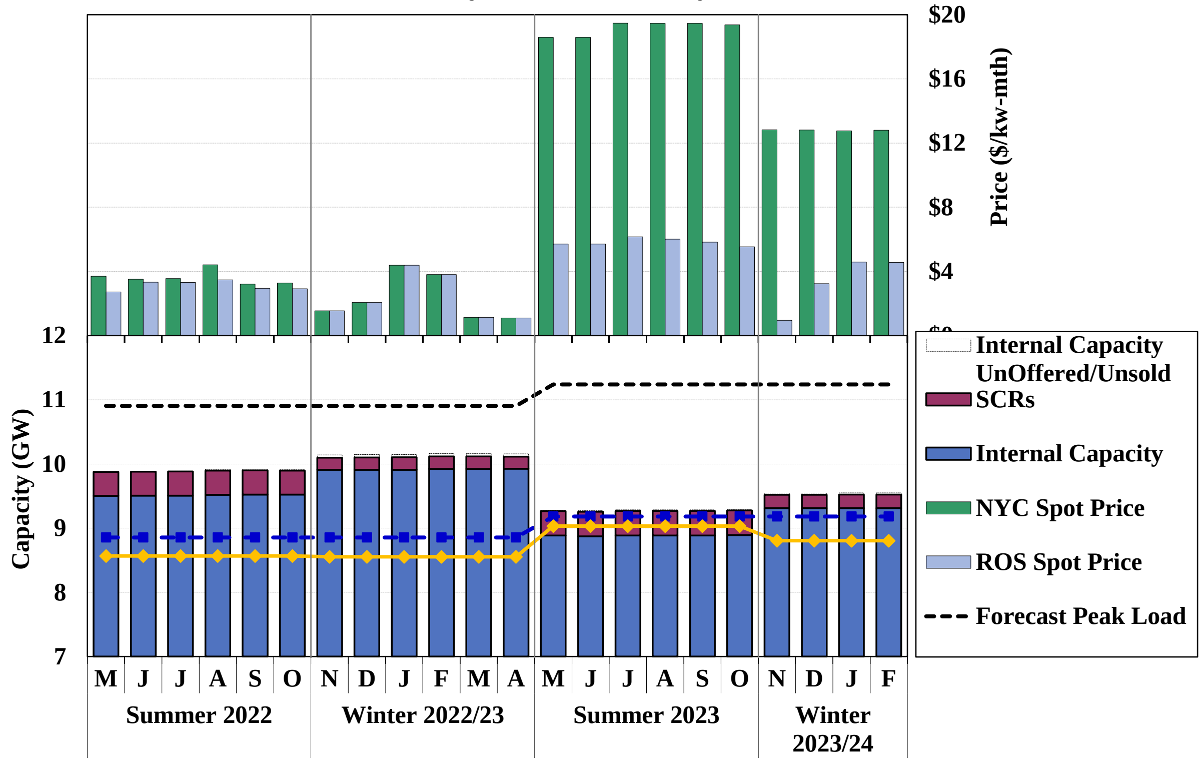


Figure A-120: UCAP Sales and Prices in Long Island
May 2022 to February 2024

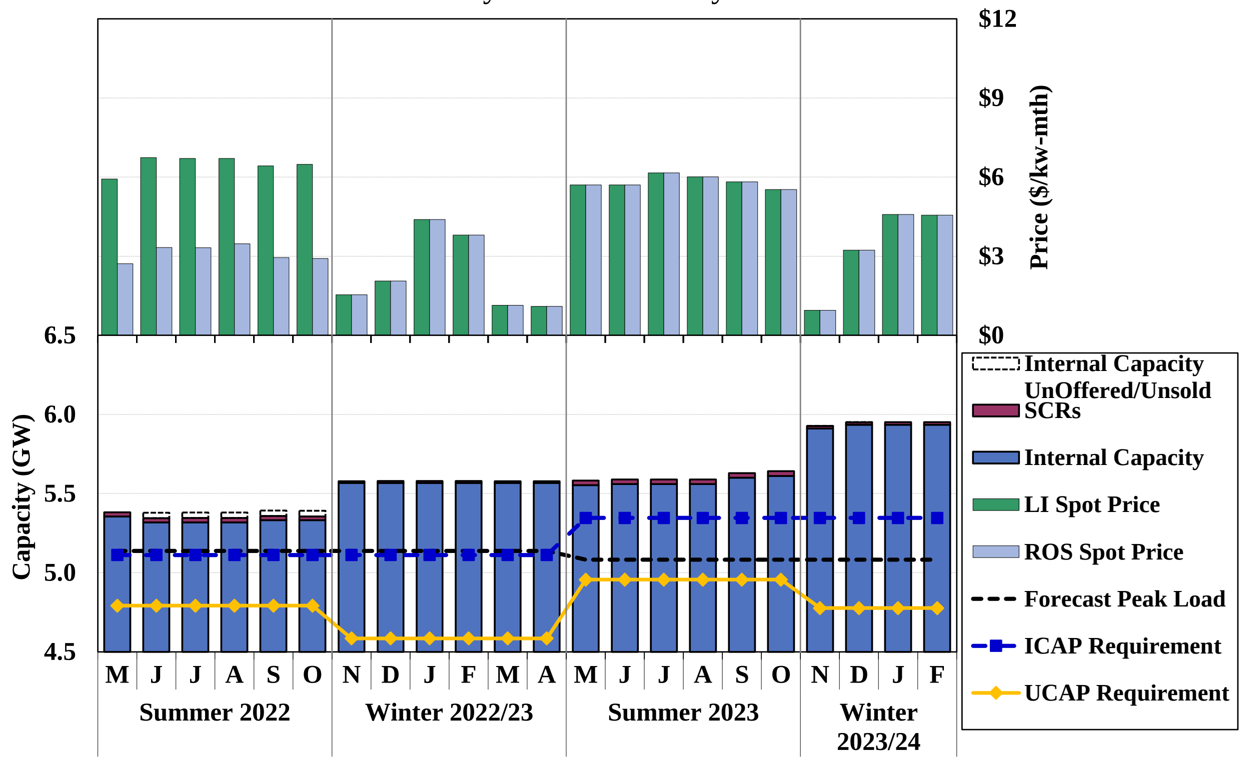
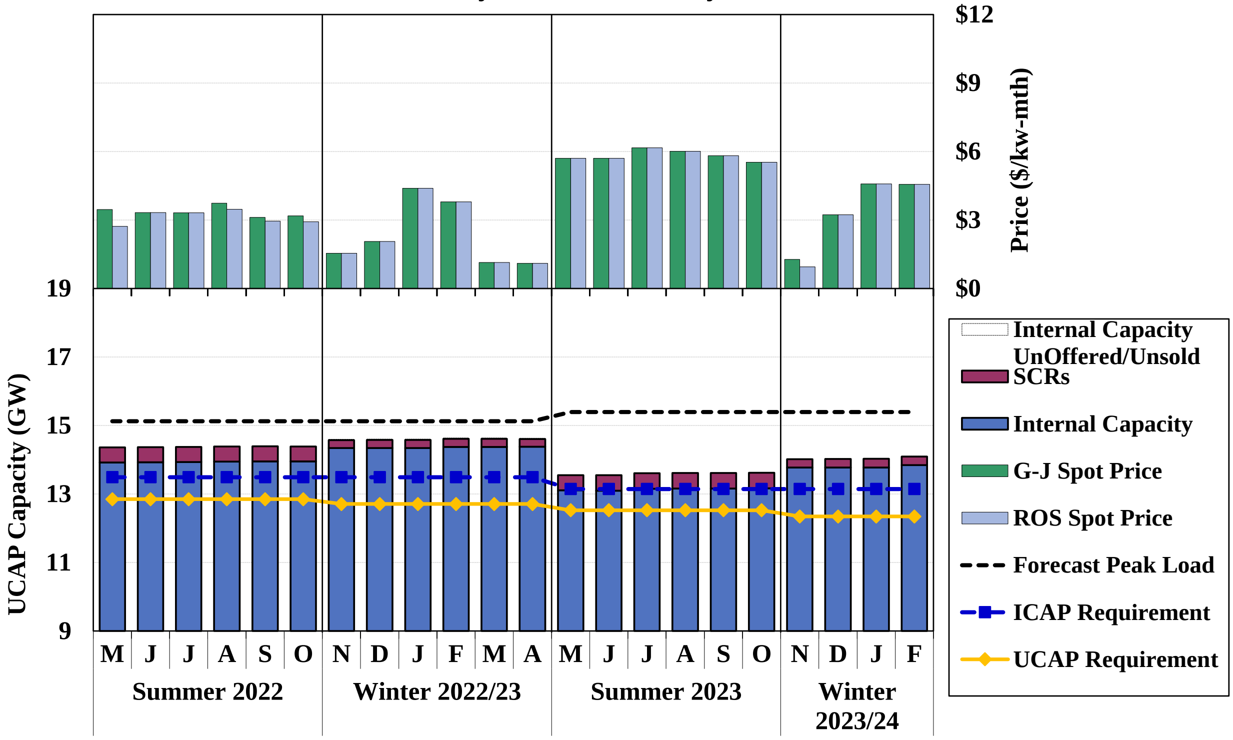


Figure A-121: UCAP Sales and Prices in the G-J Locality
May 2022 to February 2024

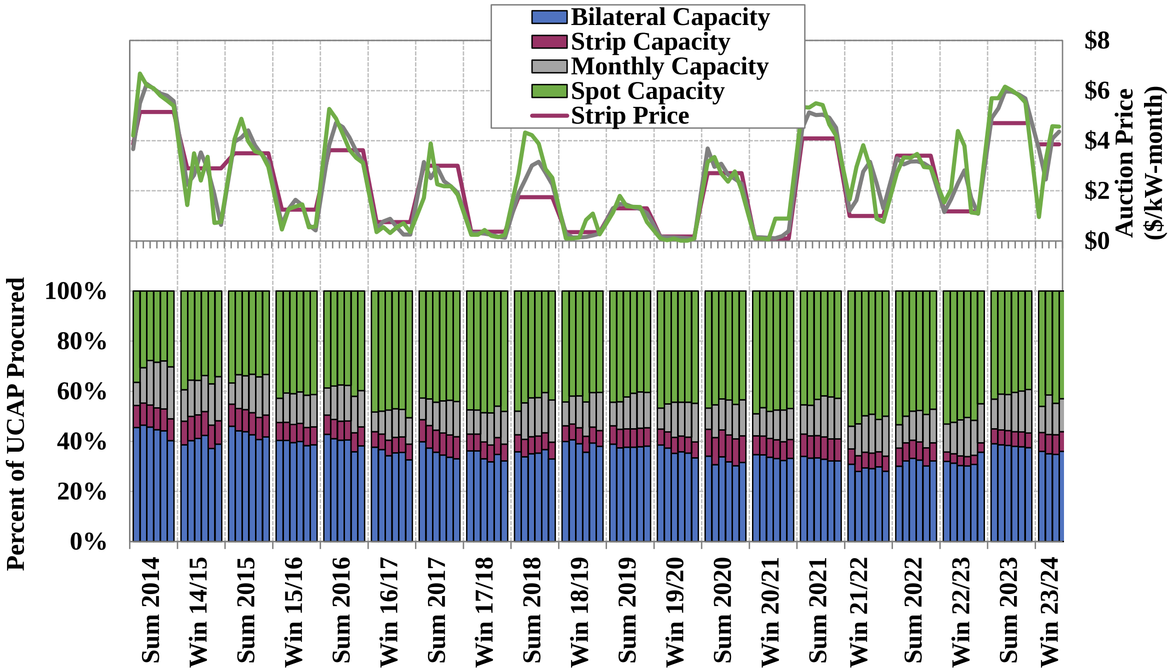


In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-122: Capacity Procurement by Type and Auction Price Differentials

Figure A-122 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 2014 capability period on a dollar-per-kilowatt-month basis.

Figure A-122: Auction Procurement and Price Differentials in NYCA
May 2014 – February 2024



E. Resource Adequacy Modeling Framework and Assumptions

Potomac Economics' Resource Adequacy Tool 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. Potomac's Resource Adequacy Tool 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. The Resource Adequacy Tool 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: These are currently not modeled directly. Instead, emergency import patterns representing variations in available external supply are modeled in each run year.
- Intermittent resources: These 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 have reduced availability in winter based on a relationship between non-firm gas availability and daily winter peak load.
- Energy limited resources ("ELRs"): ELRs such as battery storage are modeled with energy limitations and dispatched when needed to avoid load shedding. ELRs recharge in off-peak hours if sufficient supply is available on the system. The simulation uses heuristics to determine the sequence of discharge of ELRs, generally deploying resources with more remaining duration or in lower-value zones first.

The Resource Adwquacy Tool produces the following outputs for an evaluation:

- 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 VI.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-20 and Figure A-123 – Resource Adequacy Model Assumptions for Winter Accreditation Analysis

Section VIII.G discusses the impact of proposed enhancements to winter fuel availability modeling on market outcomes. We performed this analysis using the Resource Adequacy Tool with the following assumptions:

Table A-20: Resource Adequacy Model Assumptions for Winter Accreditation Analysis

Assumption	Description
Load	2023 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 2023/24 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 2023 IRM Study.
New generation capacity	2026: 500 MW of new land-based wind, 1,600 MW of new solar, 136 MW of offshore wind, and 300 MW of new battery storage 2030: 2,500 MW of new land-based wind, 2,700 MW of new solar, 4,100 MW of new offshore wind, and 2,250 MW of new battery storage
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 2022 RNA MARS topology. For 2030/31, included upgrades based on estimated MARS limit impact of Long Island PPTN projects from the 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. 1,900 MW firm gas modeled in zones F-K in winter based on recent NYISO fuel surveys
External Assistance	From 0 MW to 2,000 MW in summer and 0 MW to 1,000 MW in winter
SCRs	Included based on 2023 enrollment levels

Our analysis of how accreditation could be affected by winter fuel security modeling compared an approach intended to simulate the current NYISO/NYSRC modeling proposal for winter fuel modeling (the “Fixed Derate” modeling approach”) with a modeling approach that tracks remaining oil inventories chronologically. We included the following modeling features in this analysis:

Oil inventories: In the inventory tracking modeling approaches, 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.

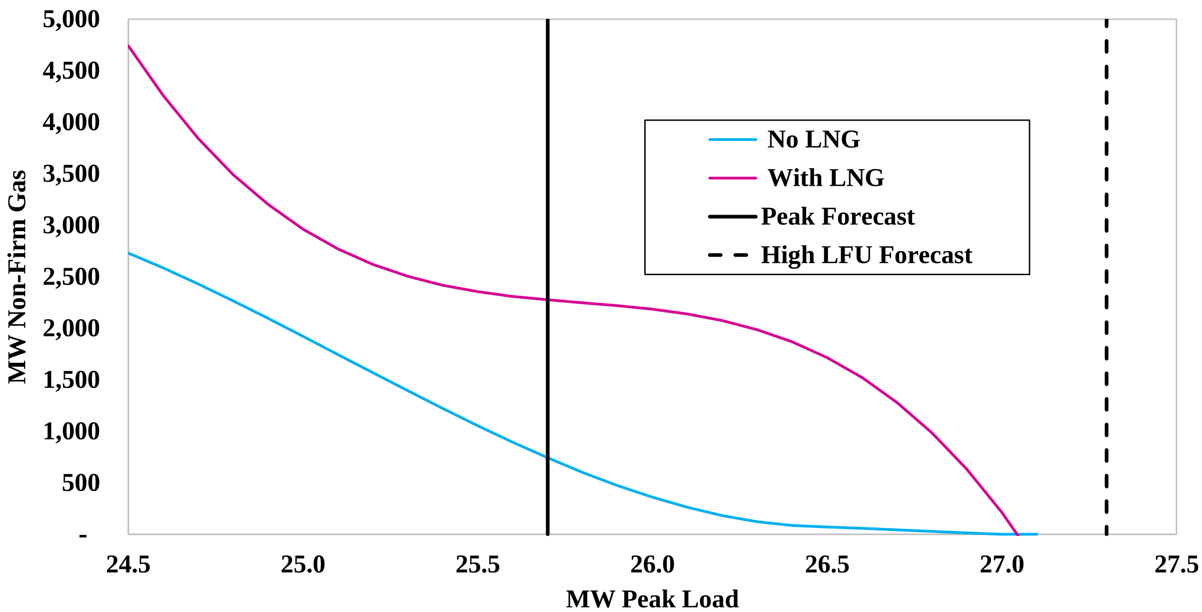
In the fixed derate modeling approach, we calculate a derating factor for each unit based on the proportion of its capacity that could run for 96 hours over six days. This calculation considers each unit's starting fuel level and time to replenishment from recent NYISO fuel surveys. Based on this approach, we calculate an aggregate derate of approximately 640 MW in winter. Generator forced outages are applied to the units' remaining capacity.

Non-Firm Gas: we estimated a relationship between daily winter peak load and daily maximum non-firm gas generation using the approach described in Section VIII.G. In the cases using the inventory tracking modeling approach, 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-123 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). In both cases, there is no available non-firm gas at higher levels of load-forecast uncertainty. However, there is more non-firm gas available at some load levels above the baseline peak load forecast when LNG is included.

Figure A-123: Modeled Non-Firm Gas Availability at Each Daily Peak Load Level

2026/27 Case



F. Cost of Reliability Improvement from Additional Capacity

An efficient capacity market signals 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 the NYISO market at meeting it. Since the inception of the 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, the 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.

The NYISO's methodology for determining the LCRs beginning the 2019/2020 Capability Year ("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-21: Cost of Reliability Improvement

Table A-21 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.[362] An Excess Level is assumed so that the demand curve in each area is set sufficiently high to ensure the system never exceeds the 0.1 LOLE criteria. This modest excess results in an LOLE of 0.052 in the 2024/25 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 2024/2025 Capability Year.

362 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 350 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.

- *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.[363]
- *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.[364, 365] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

Table A-21: Cost of Reliability Improvement
2024/25 Capability Year

Locality/Zone	**Net CONE of Demand Curve Unit** *$/kW-yr*	**NYCA LOLE at Excess Level**	**LOLE with 100 MW UCAP Addition**	**Marginal Reliability Impact** *ΔLOLE per 100MW*	**Cost of Reliability Improvement** *MM$ per 0.001 ΔLOLE*
NYCA					
A	$72		0.047	0.0048	$1.5
B	$72		0.047	0.0048	$1.5
C	$72		0.047	0.0051	$1.4
D	$72		0.047	0.0051	$1.4
E	$72		0.046	0.0052	$1.4
F	$72		0.047	0.0051	$1.4
G-J Locality		0.052			
G	$79		0.047	0.0051	$1.5
H	$79		0.047	0.0051	$1.5
I	$79		0.047	0.0051	$1.5
NYC					
J	$151		0.047	0.0051	$3.0
Long Island					
K	$61		0.046	0.0060	$1.0

363 These values were obtained by starting with the system at Excess Level with an LOLE of 0.0052 and calculating the change in LOLE from a 100-MW perfect capacity addition in each area.

364 Example for Zone F: $72/kW-year × 1000kW/MW ÷ (0.0047 LOLE change/100MW) × 0.001 LOLE change = $1.4 million.

365 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-124 and Figure A-125: Cost and CRI Curves in LCR Optimizer

Figure A-124 and Figure A-125 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.[366] 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 the NYISO minimizes overall consumer costs.[367] 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.[368] For example, Figure A-124 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-124 shows the marginal cost of capacity per kW-year, while Figure A-125 shows the CRI curve. Each CRI curve equals the marginal cost curve from Figure A-124 divided by the marginal reliability impact of capacity in the locality.[369] [370] 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-125, 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. 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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366 This is because the first-order conditions of the investment cost minimizing optimization problem include the Net CONE functions in each location.

367 The marginal cost function is derived from the first order conditions of the consumer cost minimization problem.

368 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.

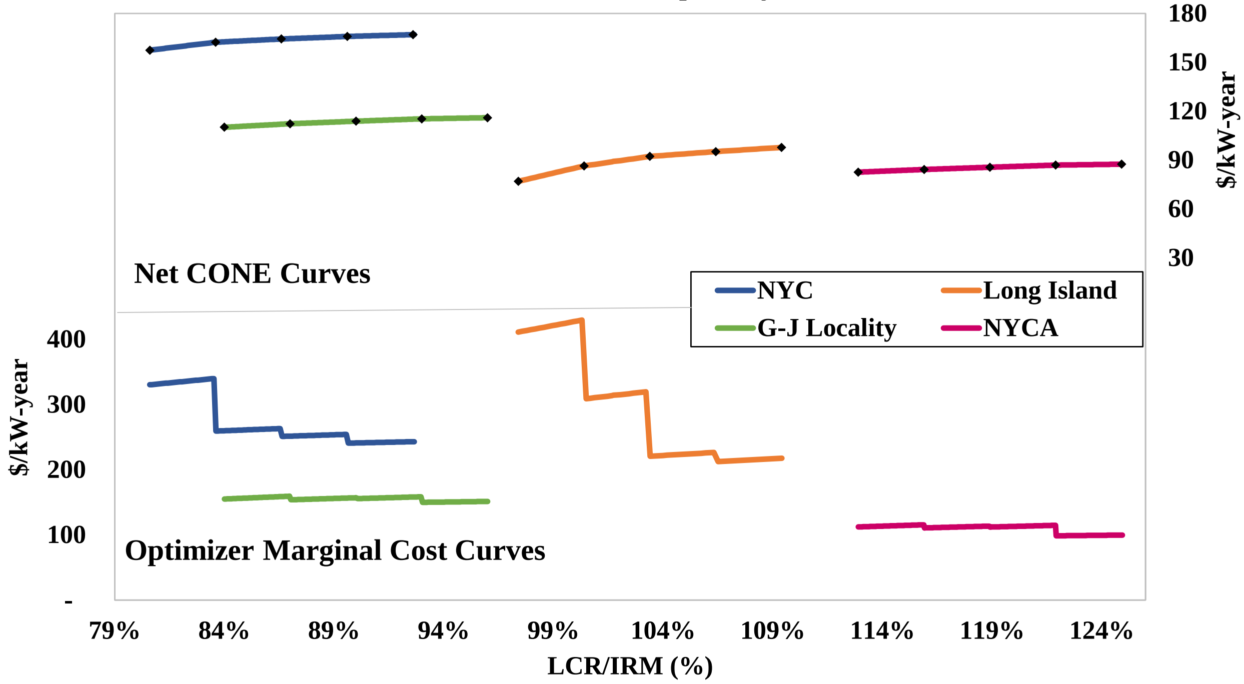
369 We simulated MRI curves based on a set of MARS-derived LOLE values for various combinations of LCRs. Because all possible combinations of LCRs cannot be feasibly tested, the MRI curves are approximate.

370 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).

- 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.

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.[371]

Figure A-124: Optimizer Cost Curves vs. Net CONE Curves
2022/2023 Capability Year

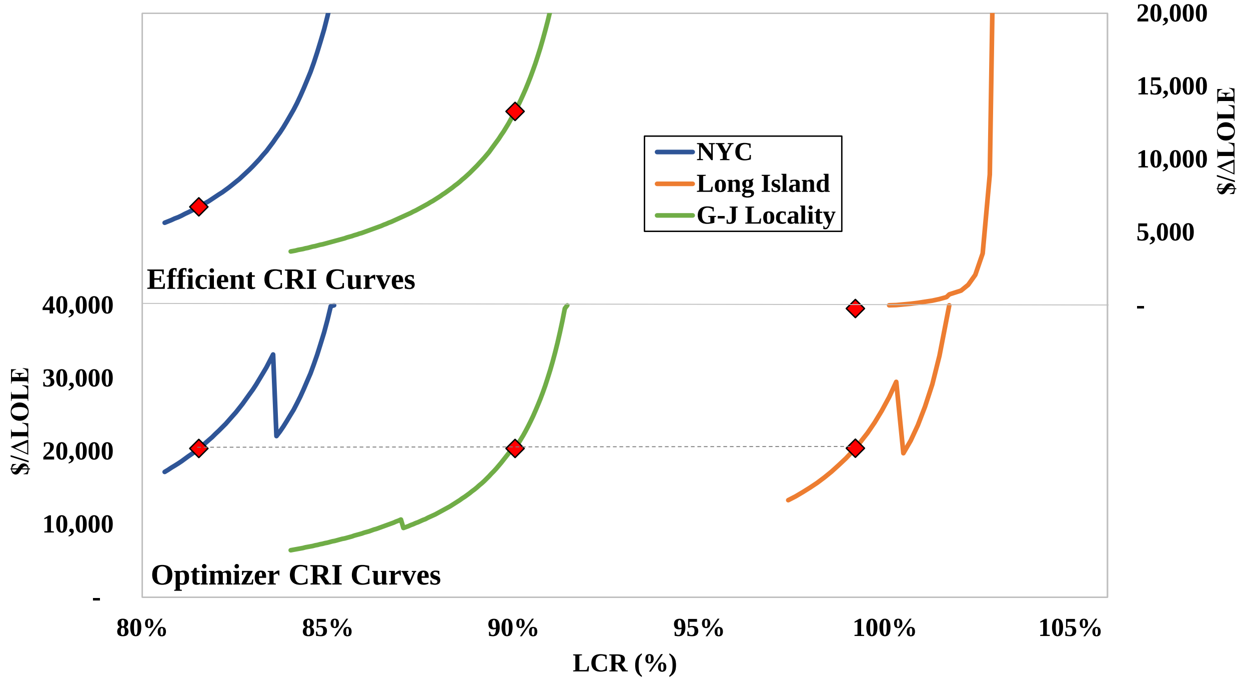


In 2023, the NYISO developed a market design proposal that would use an objective function designed to minimize investment costs.[372] NYISO proposes to deploy its LCR improvements for the 2025/26 capability year. We support the NYISO's proposal, which is needed to produce efficient LCRs using the Optimizer.

371 The simulated LCRs indicated by the red diamonds in Figure A-125 differ slightly from the actual 2022/23 LCRs because MRI was simulated using a limited number of MARS data points.

372 See NYISO presentation to December 13, 2023 Business Issues Committee, available here.

Figure A-125: Optimizer CRI Curves vs. Efficient CRI Curves
2022/2023 Capability Year



G. Mathematical Example of Capacity Constraint Pricing Credit 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 price between the capacity 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-22 through Table A-24 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).[373] 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.

373 The examples in this section assume constraints based on thermal limits where GSFs can be used to accurately estimate flows on the limiting facility. For constraints where this is not the case (such as some voltage-based limits), a different approach to calculate CCP Factors would be used.

Table A-22: 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-23: 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-24: 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

Capacity Constraint Pricing Factors with Two Transmission Constraints

Table A-25 through Table A-27 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-22, 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-25: 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-26: 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-27: 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.[374]

Figure A-126: Breakdown of Revenues for Generation and Transmission Projects

Figure A-126 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.[375]

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374 See Recommendation 2012-1c in Section XII.

375 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:

- 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.

- FCTR revenues for the 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.[376]

- 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.

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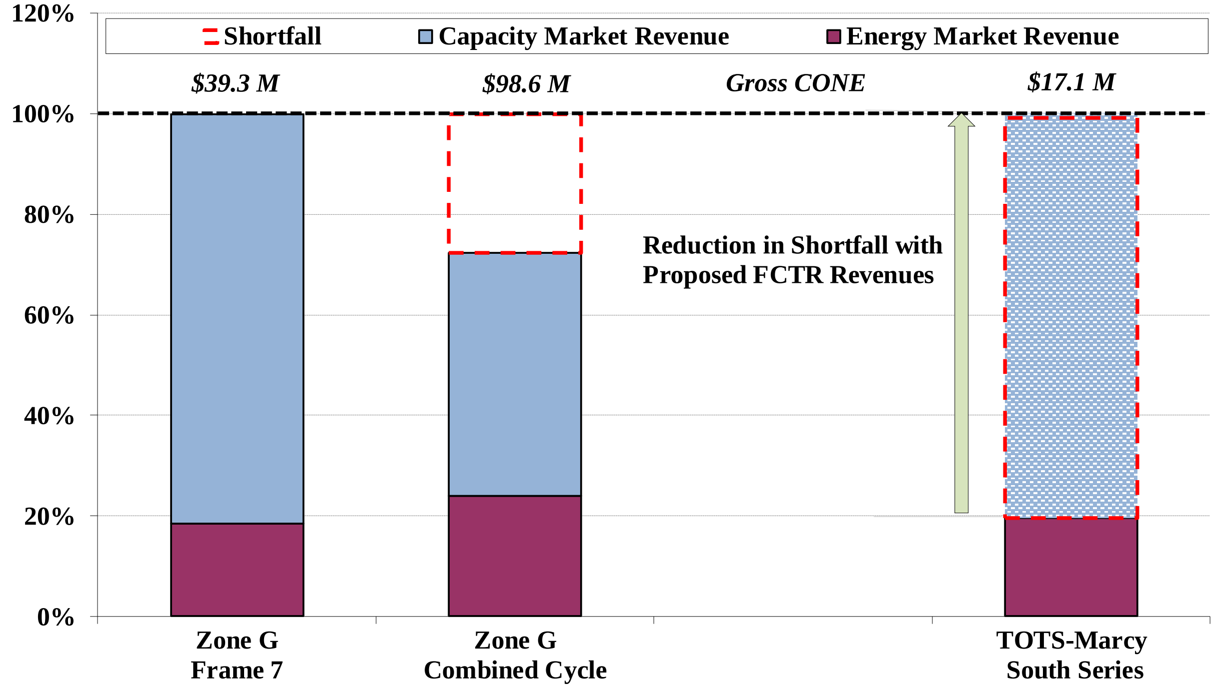
a) Carrying charge of 9.2 percent based on the WACC developed in the 2016 demand curve reset study, a 40 year project life and 15 years MACRS depreciation schedule.

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.

376 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

Figure A-126: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



I. Assessment of Capacity Accreditation Approaches

NYISO has recently adopted market changes that will accredit capacity suppliers based on each resource's Marginal Reliability Improvement (MRI) value beginning in the 2024/25 capability year. This approach differs from other methods that have been used for capacity accreditation, including Effective Load Carrying Capacity (ELCC) and simple heuristic approaches. In this subsection, we explain the difference between our recommended MRI approach and ELCC and discuss the advantages of MRI.

Approaches to Capacity Accreditation

Capacity credit refers to the amount of megawatts a resource is allowed to offer in capacity market auctions. All frameworks to establish capacity credit use methods to discount each resource's capacity, so that capacity credit reflects only what can be reliably counted on during periods of critical system need. In the NYISO market capacity credit is referred to as Unforced Capacity (UCAP). For conventional resources, UCAP is determined using the resource's EFORd, a measure of how likely it is to experience a random outage when needed.

The concept of capacity credit is closely related to the system's reliability metric, which represents how reliable the system is. NYISO targets a Loss of Load Expectation (LOLE) of 1 day in 10 years. This criterion is used to determine capacity market requirements (the IRM and LCRs), which are derived from simulations of LOLE that consider every resource's availability during hours when load shedding might occur. Ultimately, every resource's capacity credit should reflect its marginal impact on LOLE. Hence, a MW of UCAP from any resource type should correspond to a comparable impact on LOLE.

For some resource types, EFORd alone is not applicable or is not sufficient to reflect the resource's marginal impact on LOLE. Examples include intermittent renewables, energy-limited resources, very large conventional generators, and generators that can experience a common loss of a limited fuel supply (such as a pipeline outage) which they share with other generators. One reason that EFORd alone does not accurately describe these resources' impact on reliability is that EFORd represents the probability of random uncorrelated outages, but these resource types pose the risk of correlated outage or limited availability of a large amount of capacity under peak conditions.

There are multiple methods to assess the capacity credit of these resources. Capacity credit is often described relative to a hypothetical unit of 'perfect capacity' which is always available:

- Marginal Reliability Impact (MRI) – measures how an incremental amount of capacity of Resource X impacts LOLE, relative to how the same amount of 'perfect capacity' impacts LOLE.

- Effective Load Carrying Capacity (ELCC) – measures the MW quantity of 'perfect capacity' that would produce the same LOLE as a given quantity of Resource X. ELCC approaches may be marginal or average, discussed further below.

- Heuristic approaches – estimate capacity credit based on rule-of-thumb approaches, such as a resource's average output in a predetermined set of hours.

Current NYISO Approach

NYISO has historically determined capacity credit of intermittent and energy-limited resources using simple heuristics. These capacity credit values were updated every four years through the Tailored Availability Metric and Expanding Capacity Eligibility processes, respectively. In both cases, resource adequacy modeling (including ELCC metrics) informed the approach, but capacity credit was ultimately set in a holistic manner based on the NYISO's judgement. This approach is not guaranteed to align with a resource's impact on LOLE in each year.

In early 2022, NYISO filed tariff revisions to revise its capacity accreditation approach beginning in the 2024/2025 capability year, and these were approved by FERC in May 2022. NYISO developed implementation details for its new accreditation approach in 2022 and 2023.[377] Under the new rules, Capacity Accreditation Factors (CAFs) will be calculated for each resource class (e.g. group of resources with similar characteristics) for each capacity zone. The Capacity Accreditation Factors will reflect the resource class's marginal reliability contribution, calculated using NYISO's resource adequacy model used to determine the IRM and LCRs.

NYISO currently does not adjust capacity credit for very large conventional generators or for units with common fuel supply limitations or risks. These units' UCAP is determined using their EFORd. A common outage would subsequently cause the EFORd of affected units to increase

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377 These details have been incorporated into NYISO's ICAP Manual – see Section 7 (Annual Process to Establish Capacity Accreditation Resource Classes, Capacity Accreditation Factors, and Peak Load Windows). For the latest CAF values, see NYISO's capacity accreditation webpage, available here.

temporarily, but there is no mechanism to preemptively reflect correlated risk of these units in their UCAP. NYISO developed proposed modeling and accreditation improvements for gas resources with fuel constraints in 2023 – see detailed discussion in Section VIII.G.

Illustrative MRI and ELCC Approaches

MRI and ELCC approaches to capacity accreditation both rely on a probabilistic resource adequacy model that simulates LOLE. NYISO uses GE-MARS software to plan its capacity market requirements. MARS is a Monte Carlo model that inputs the existing resource mix and simulates a large variety of load and resource outage conditions to estimate the likelihood of loss-of-load events.

Both MRI and ELCC approaches add or remove generation or load in MARS and simulate LOLE. The following are examples of generalized calculation approaches, although there are multiple variations of each approach:

Example MRI Approach

An example of an MRI calculation is as follows:

1. Begin with a base case simulation reflecting the current system resource mix, with load increased so that LOLE = 0.1 days per year.
2. Add 50 MW of Resource X to (1). Calculate LOLE, which will be lower than 0.1 because the system will have more resources available.
3. Add 50 MW of perfect capacity to (1). Calculate LOLE, which will be lower than 0.1.

The MRI of Resource X is the ratio of the change in LOLE in step 2 to the change in LOLE in step 3: $MRI_X = (0.1 – LOLE2) / (0.1 – LOLE3)$. This will be less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.[378]

Example ELCC Approach

ELCC methods determine how much load or perfect capacity could be replaced with a given quantity of Resource X while holding LOLE constant.[379] An example of an ELCC calculation, based on a recent proposal in PJM,[380] is as follows:

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378 The amount of resource added in the MRI simulation can vary, but should be small enough so that it reflects an incremental change to the system as a whole. Our preliminary analysis suggests that a size of 50-100 MW is small enough to calculate a marginal impact while producing an MRI function that is monotonic with the quantity of capacity in a given location.

379 There are many variations of ELCC methods, including whether the starting simulation is at or below criteria and the order in which the studied resource and perfect capacity or load are added/removed from the model. This section outlines one recent proposed approach. For a general description, see NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, March 2011.

380 This is a stylized simplification of PJM's proposal – see filings by PJM Interconnection L.L.C. in FERC Docket ER21-278-000, especially October 28, 2020 Affidavit of Dr. Patricio Rocha Garrido.

1. Begin with a base case simulation reflecting the current system resource mix, including any MWs of Resource X. Increase load so that LOLE = 0.1 days per year.
2. Remove the capacity of Resource X from (1). LOLE will be above 0.1, because the system has less capacity and is therefore less reliable than (1).
3. Add perfect capacity to (2) until LOLE returns to 0.1.

The ELCC of Resource X is the quantity of perfect capacity added in (3) divided by the quantity of capacity of Resource X subtracted in (2). This percentage is less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.

A marginal ELCC approach subtracts only a small quantity of Resource X in (2), while an average ELCC approach subtracts all capacity of Resource X. For example, if 5,000 MW of Resource X already exists, marginal ELCC might consider how much load can be served by the next 50 to 100 MW of Resource X, while average ELCC would consider how much load can be served by all 5,000 MW. A portfolio ELCC approach is similar to average ELCC, but considers how much total load is served by a portfolio of multiple technologies simultaneously.

Comparison of MRI and ELCC Approaches

We support NYISO's use of MRI to determine capacity accreditation. The key feature of MRI is that it reflects a resource's marginal impact on LOLE, so it is consistent with ensuring reliability and with the principles of NYISO's capacity market.

MRI and Marginal ELCC approaches are likely to produce very similar capacity credit results. Both approaches fundamentally consider how LOLE is affected by an incremental quantity of Resource X compared to an incremental quantity of perfect capacity. MRI is likely to be easier to implement because it requires a fixed number of MARS runs from a common base case (i.e., step 2 and step 3 make independently-determined adjustments to the base case in step 1), while for ELCC MARS must be run iteratively (i.e., step 3 depends on the results of step 2, and determining the inputs to step 3 require some interpretation of the results of step 2). Thus, MRI methods can be automated, while ELCC methods cannot be fully automated.

Marginal approaches are preferable to average ELCC or heuristic approaches. The NYISO capacity market (and the NYISO markets in general) are designed based on the fundamental principle of economics—that prices should be consistent with the marginal cost of serving load so that suppliers have incentives to sell when their marginal cost is less than or equal to the marginal value to the system. Average ELCC methods divorce the payment an individual resource receives from its actual impact on reliability when choosing to enter the market, retire or repower. Hence, average ELCC methods provide very inefficient investments incentives.

A marginal approach such as MRI therefore offers several advantages:

- Investment signals – MRI and marginal ELCC provide efficient signals for investment and retirement. As the resource mix evolves, these signals will be vital for guiding investment in clean resources. Marginal capacity credit is key to providing incentives for investors to:

- Avoid technologies that have over-saturated the market. If an average or fixed credit is used, investors generally ignore this concern;
- Add storage to intermittent renewables. If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Choose between storage projects with different durations by efficiently trading off cost and value to the system;
- Augment the duration of storage over time (for example, by adding more batteries to an existing project). If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Efficiently repower renewable projects when they approach the end of their useful lives; and
- Be more likely to retire existing generators without a reliable fuel supply during peak conditions rather than generators with fuel storage capability.

- Diversity benefits – marginal accreditation indicates the value of gaining or losing capacity of a resource type, given all the other resources in the system. As such, it accurately signals (a) diminishing returns of resources with correlated availability, and (b) the value of adding capacity of a type that complements other resources in the system. For example, if high penetrations of solar shift critical hours to an evening peak over time, the marginal capacity credit of storage would tend to increase. Average ELCC approaches also consider diversity impacts, but the resulting signals are dulled because they don't reflect how the next unit of capacity interacts with the existing resource mix.
- Avoids overpayment – marginal accreditation secures reliability at the lowest cost by paying each resource based on its marginal value to the system. Capacity prices therefore reflect the price needed to attract or retain capacity at the current level of reliability.

An example of another market concept that relies on marginal payment is the capacity market demand curves, which pay all resources a uniform clearing price – even though capacity up to the IRM or LCR requirement theoretically provides more value than surplus capacity after that point.

By contrast, average or portfolio ELCC approaches would directly cause UCAP requirements in the capacity market to increase, causing consumers to pay more than what is needed to attract or retain capacity. In other words, attributing UCAP to a resource in excess of its marginal contribution to reliability simply causes an offsetting increase in UCAP requirements, resulting in a transfer from consumers to suppliers.

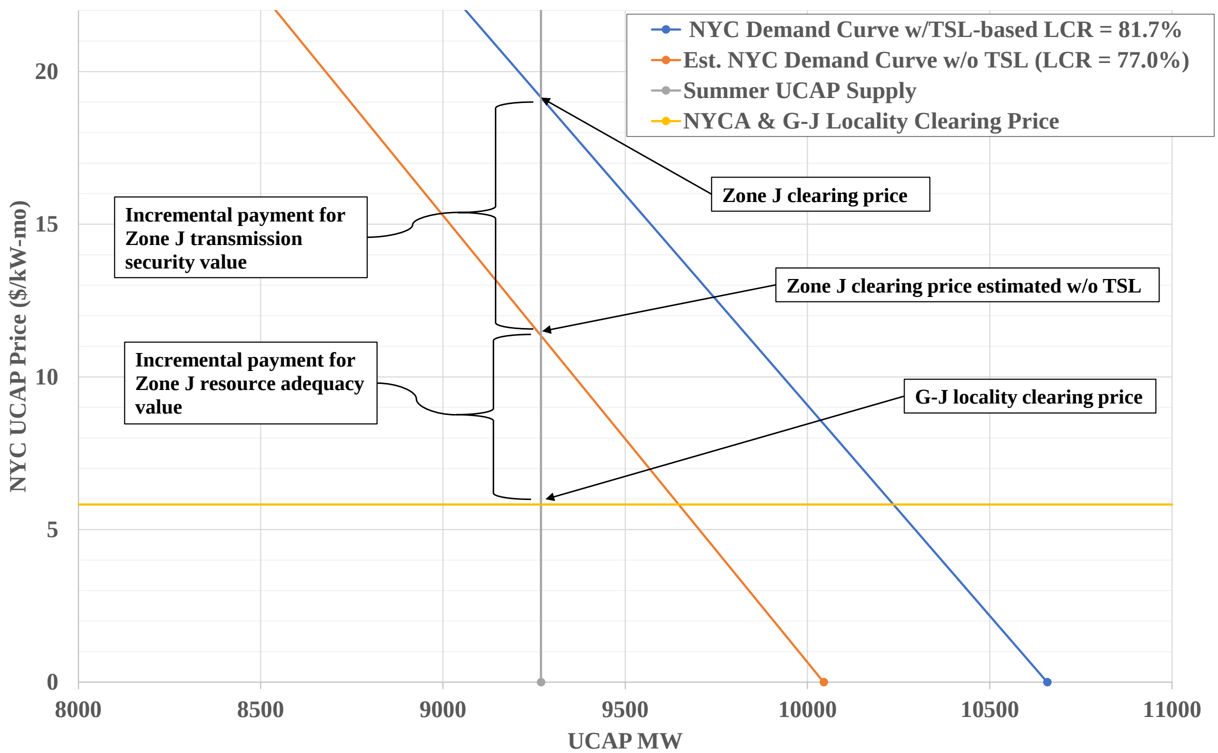
J. Example of Capacity Payments Under Transmission Security Proposal

In this report, we recommend paying resources the highest capacity price among requirements which they contribute to meeting (see Recommendation 2022-1) [381]. Likewise, NYISO and stakeholders recognized the need to consider capacity market incentives related to transmission security by designating "Valuing Transmission Security" for "Issue Discovery" in the 2024 project prioritization plan.

The remainder of this section provides additional details of an approach that could be used to implement Recommendation 2022-1. This would require the NYISO to develop two-part pricing for resources in capacity regions where the LCR is set by transmission security criteria. Specifically, the capacity price should be broken into components for resources based on their contributions to resource adequacy and transmission security.

This two-part pricing concept is illustrated in Figure A-127, which shows a scenario when the Zone J LCR is set by a TSL of 81.7 percent, resulting in the demand curve shown by the blue line. The orange line shows the demand curve corresponding to the LCR that would be set if the TSL was not imposed, which is assumed to be 77 percent in this scenario.

Figure A-127: Recommended 2-Part Capacity Pricing when an LCR Is Based on the TSL



In this illustrative scenario, the G-J Locality clearing price is $5.90 per kW-month and the Zone J clearing price is $19 per kW-month. The clearing price for the resource adequacy contribution is

381 See Section XII and Section VIII.E.

$11.50 per kW-month, which is based on the reduced LCR for Zone J that excludes consideration of the TSL. In this scenario, the incremental price for the resource adequacy value of Zone J resources would be $5.60 (= $11.50 – $5.90) per kW-month, while the incremental price for the transmission security value of Zone J resources would be $7.50 (= $19 – $11.50) per kW-month. Most Zone J resources would be paid the full Zone J clearing price of $19 per kW-month, while Zone J resources that do not contribute to transmission security would be paid $11.50 per kW-month based their resource adequacy value.

To illustrate how this would be used in practice, we show illustrative settlements for three hypothetical resources in Zone J:

- SCRs – These would receive $11.50 per kW-month of UCAP based on the resource adequacy value of Zone J resources.
- 1000 MW generator – If we assume the third-largest contingency for Zone J is 720 MW and the EFORd of this resource is 5 percent, this resource would be paid for:
    - 720 MW of UCAP at the Zone J clearing price of $19 per kW-month; and
    - 230 MW of UCAP at $11.50 per kW-month, the Zone J price for resources that do not contribute to transmission security.
- 800 MW offshore wind unit – If we assume this receives an MRI of 25 percent under the soon-to-be implemented capacity accreditation rules, it would be paid for:
    - 200 MW of UCAP (based on a 25 percent MRI for its of 800 MW of ICAP) at the $11.50 per kW-month clearing price for resource adequacy in Zone J; and
    - 80 MW of UCAP (based on a 10 percent contribution for its 800 MW of ICAP) at the $7.50 per kW-month component for transmission security in Zone J.

We recommend developing a two-part pricing method (as described above) that separates payments for resource adequacy and transmission security when transmission security criteria determines the LCR. This would improve incentives to invest in reliable capacity and reduce overpayments to over-accredited resources. These changes would cause SCRs, large contingency resources, and intermittent generation to be appropriately compensated based on their contributions to the planning reliability requirements. Payments to these resources would be unaffected when LCRs are not set at the TSL-floor.

K. Analysis of NYISO's Deliverability Test Methodology

Section IV.A 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.[382] The "highway/byway" analysis is the primary test resulting in SDUs.[383] It is designed to examine whether all resources within a capacity zone are deliverable throughout that zone under a deterministic set of conditions. It uses the following general procedure:

- The capacity zone is divided into several distinct subzones based on the location of relevant transmission bottlenecks.[384]
- A base case power flow simulation is developed in which total generation in the capacity zone is brought in balance with summer peak load.[385]
- 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.

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382 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."

383 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.

384 These subzones may correspond to individual NYISO load zones within the same capacity zone, or to local areas within one load zone.

385 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.

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 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.[386]
- 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.

NYISO recently adopted changes to the calculation of the UCDF for future Class Year studies (the "updated UCDF procedure").[387] 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.[388] 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-128 and Figure A-129 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.

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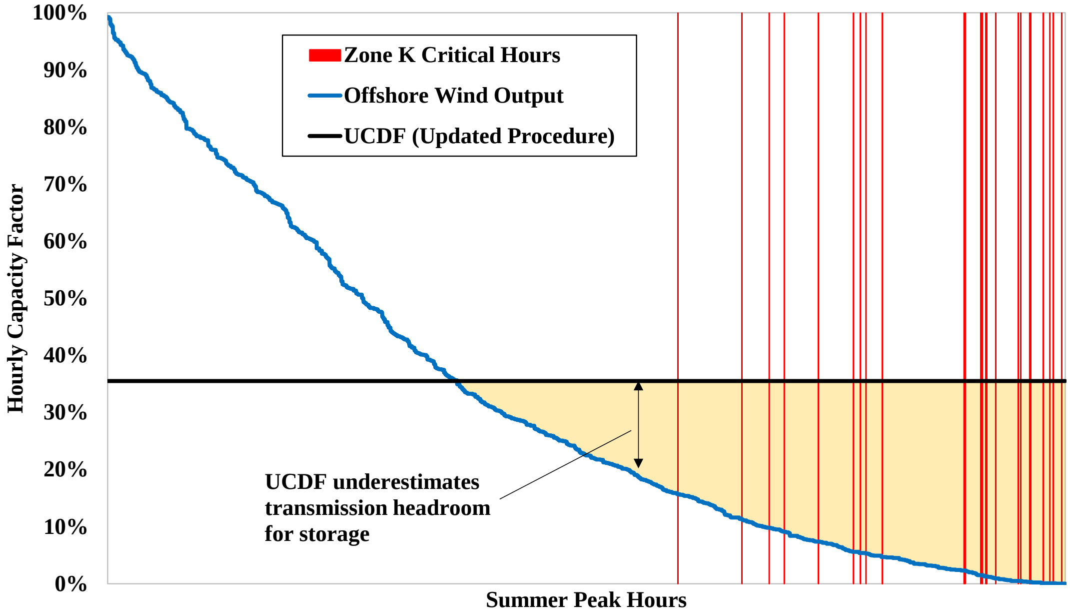
386 NYISO has adopted changes to accredit capacity suppliers based on their marginal contribution to reliability, which largely reflects their expected availability during tight hours. See Section VIII.D. See NYISO presentation to ICAPWG on November 21, 2022 "Capacity Accreditation", available here.

387 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.

388 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 taking place 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%.

Figure A-128 shows a duration curve of Long Island offshore wind output.[389] The curve shows the wind capacity factor in each hour ending 11 through 18 in June through August, arranged from highest to lowest.[390] 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 that participated in the CY21 and CY19 Class Year studies (3.1 GW of requested CRIS) are in service.[391] The red vertical lines mark the individual critical reliability hours in Long Island in the same simulation.[392]

Figure A-128: Long Island Offshore Wind Hourly Output and UCDF in Critical Hours



Critical hours in Figure A-128 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.

389 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.

390 All critical hours in the resource adequacy simulation described here took place in these hours.

391 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.

392 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 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.

Figure A-129 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.[393] 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.[394] We estimate the amount of 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 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.[395]

- 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

393 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.

394 The deliverability test divides Long Island into West, Central and East subzones. The majority of offshore wind and storage resources in CY21 and CY19 intended to interconnect in Central and East Long Island and faced constraints in the westbound direction. For the purposes of this test, we added wind and storage in fixed proportions matching the composition of 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.

395 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). We estimated the transfer limits between Long Island subzones 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 in Figure A-129. 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 in Figure A-129.

UCAP in Long Island that can be removed in the resource adequacy simulation after adding the deliverable resources, while holding total unserved energy constant. [396]

Figure A-129: Transmission Headroom from Potential Retirements for New Resources
Deliverability Study vs. MRI Approach – East/Central Long Island Example

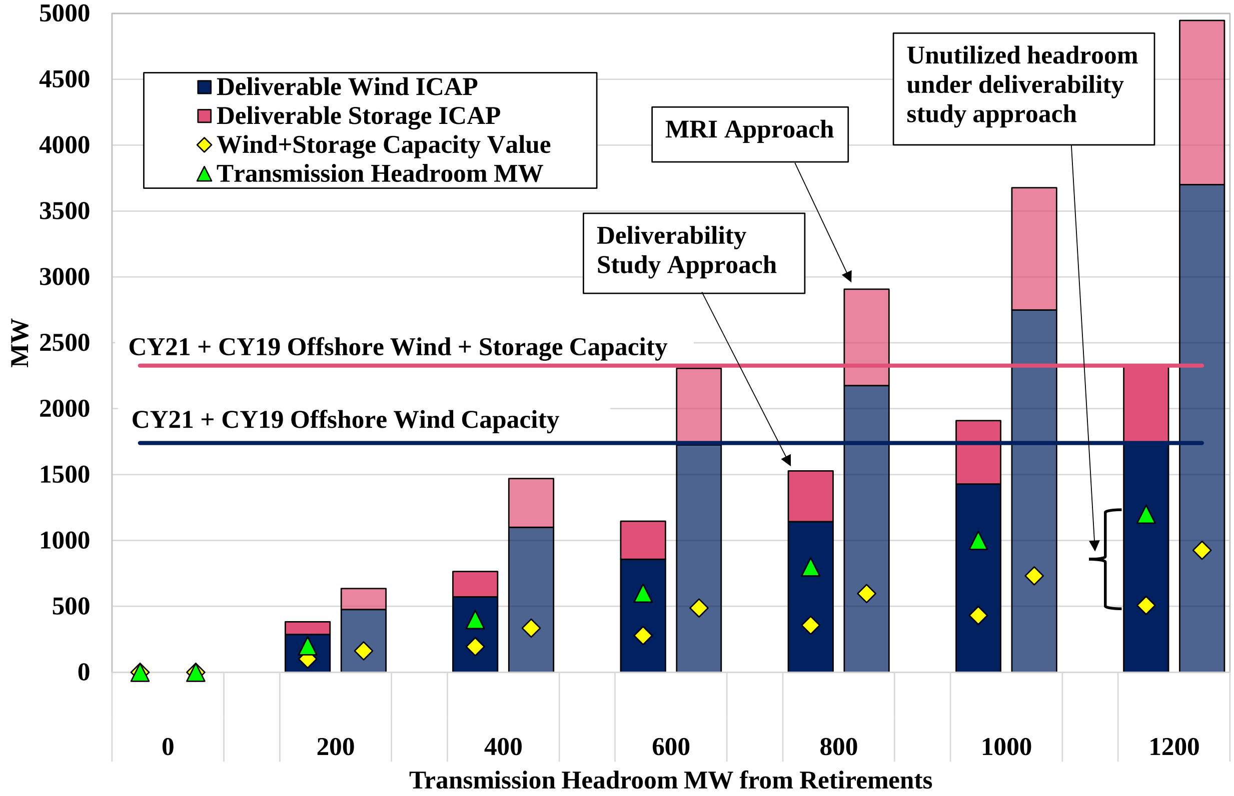


Figure A-129 shows that retirements that create transmission headroom make a smaller amount of wind and storage capacity deliverable under the UCDF method than under a probabilistic MRI approach. This is because the UCDF method overestimates offshore wind output in critical hours and does not consider 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-128.

396 We calculate the amount of conventional UCAP that can be displaced by the wind and storage resources as the headroom shown in Figure A-129 (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.

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.[397]

[397] 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.[398] 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-28 to Table A-30: 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.[399] 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-28: Day-ahead Fuel Assumptions During Hourly OFOs[400]

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

398 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.

399 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.

400 **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-29: Gas and Oil Price Indices and Other Charges by Region[401]

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
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.[402]

Table A-30: Gas-fired Unit Parameters for Net Revenue Estimates[403]

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)	10,000	15,000	17,000	9,300
Min Run Time (hrs)	24	1	1	1
Variable O&M (2023$/MWh)	$10.5	$5.3	$6.4	$1.5
Startup Cost (2023$)	$7,044	$1,408	$609	$27,675
Startup Cost (MMBTU)	3500	50	60	490
EFORd	5.14%	10.46%	19.73%	4.30%

401 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.

402 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 2021 – 2022, we show only non-ozone season revenues to reflect revenues under the future operating status of these facilities.

403 The parameters for the new CT are based on the recent NYISO ICAP Demand Curve reset study. The CONE estimate for gas-fired units in West Zone are based on preliminary cost data from Zone C in the 2020 ICAP Demand Curve reset study. See *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*.

- In 2023, 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 2023 emissions. To estimate the resulting net cost of NOx emissions in 2023, 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-130 to Figure A-132: 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-130: Net Revenue & Cost for Fossil Units in West Zone and Hudson Valley

2021-2023

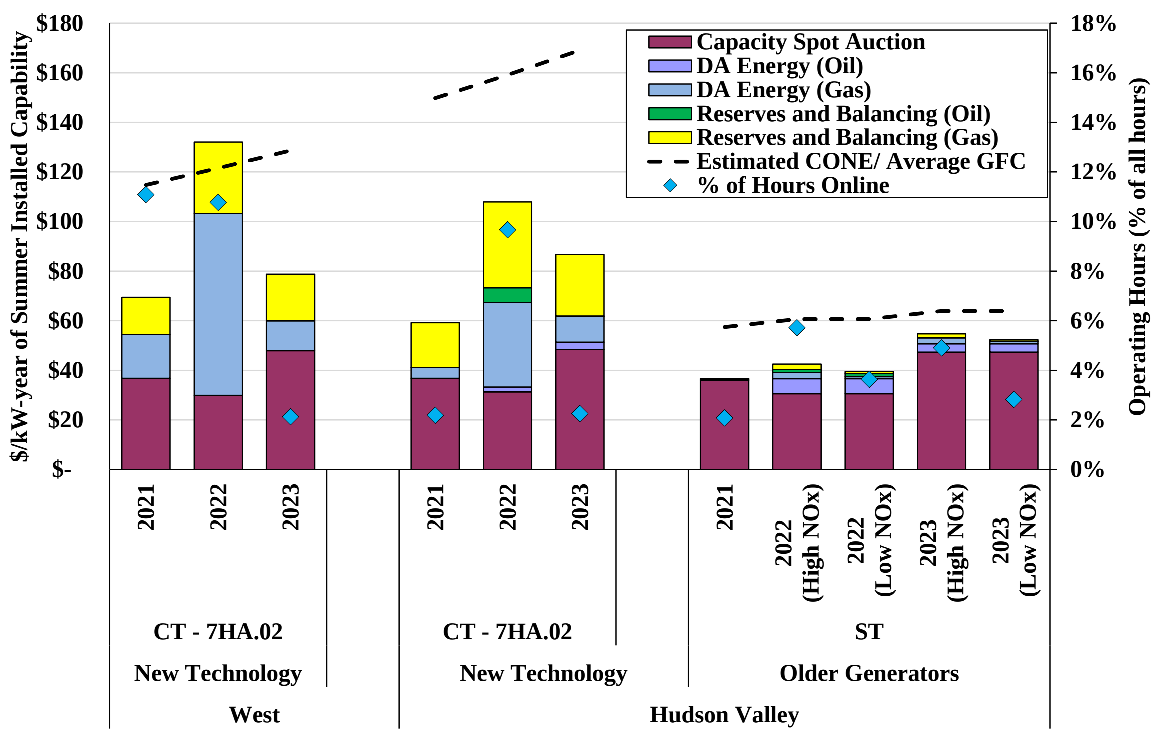


Figure A-131: Net Revenue & Cost for Fossil Units in New York City
2021-2023

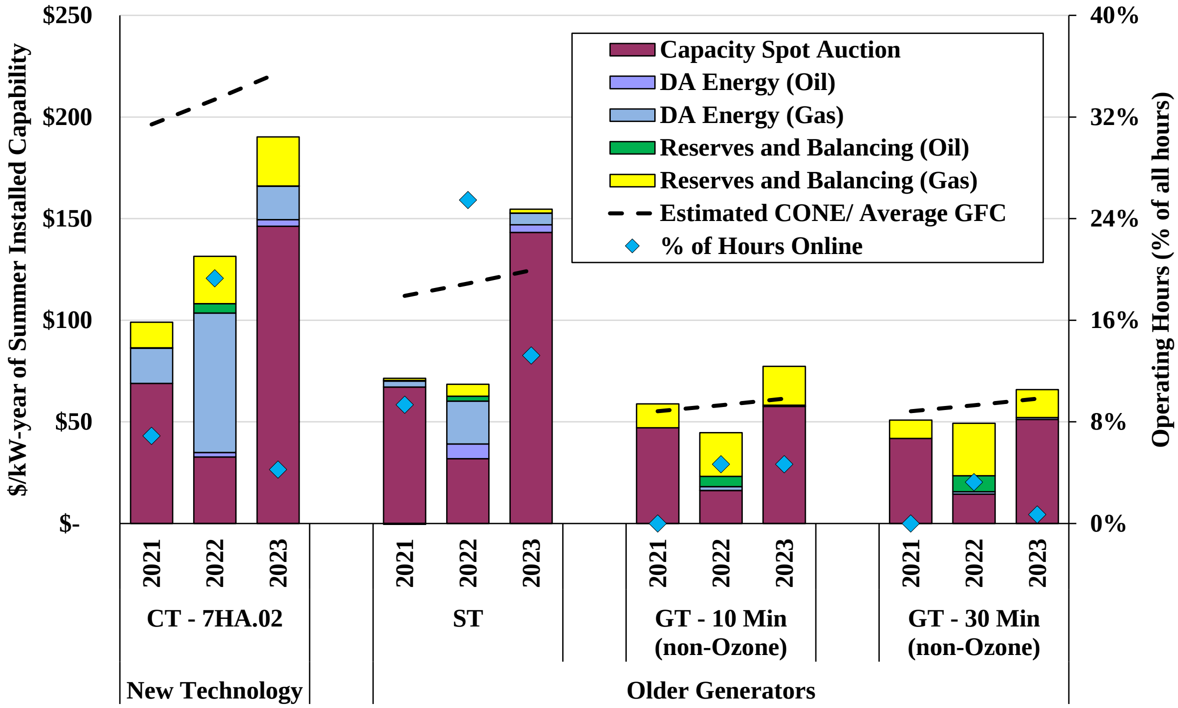
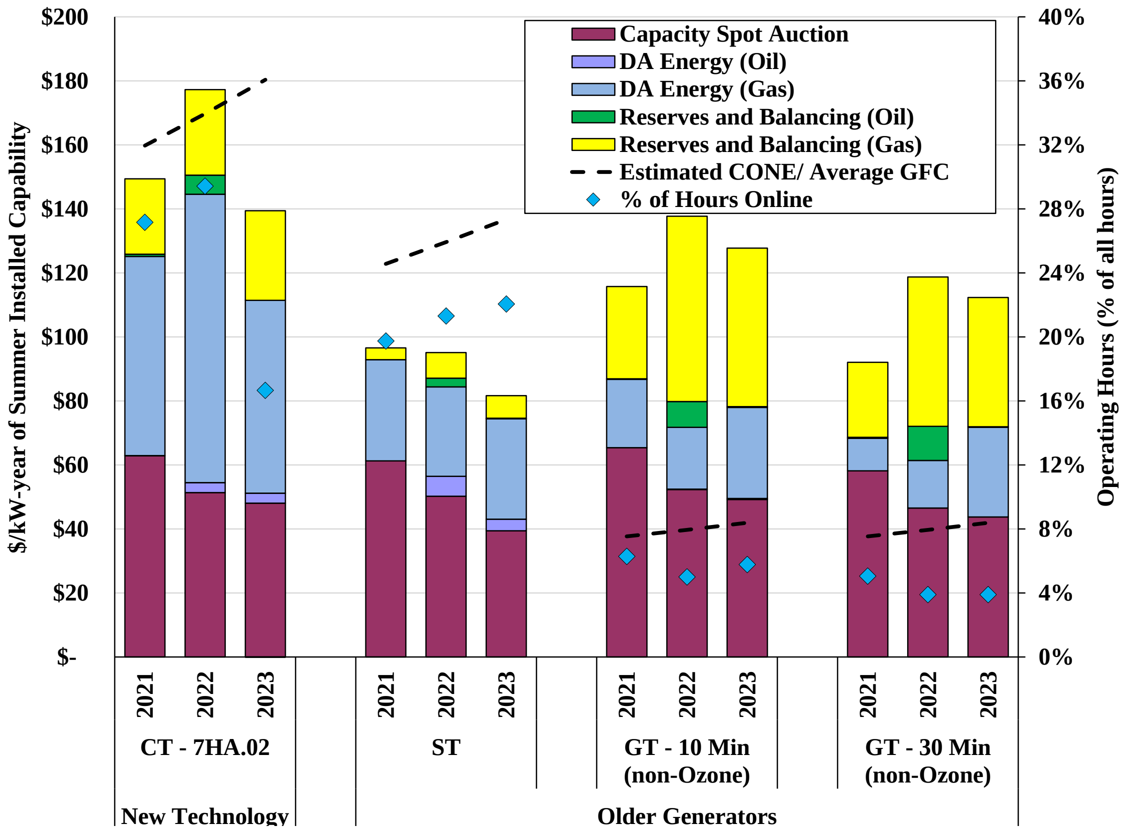


Figure A-132: Net Revenue & Cost for Fossil Units in Long Island
2021-2023



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-133: Net Revenues for Nuclear Plants

Figure A-133 shows the net revenues and the US-average operating costs for the nuclear units from 2021 to 2023. Estimated net revenues are based on the following assumptions:

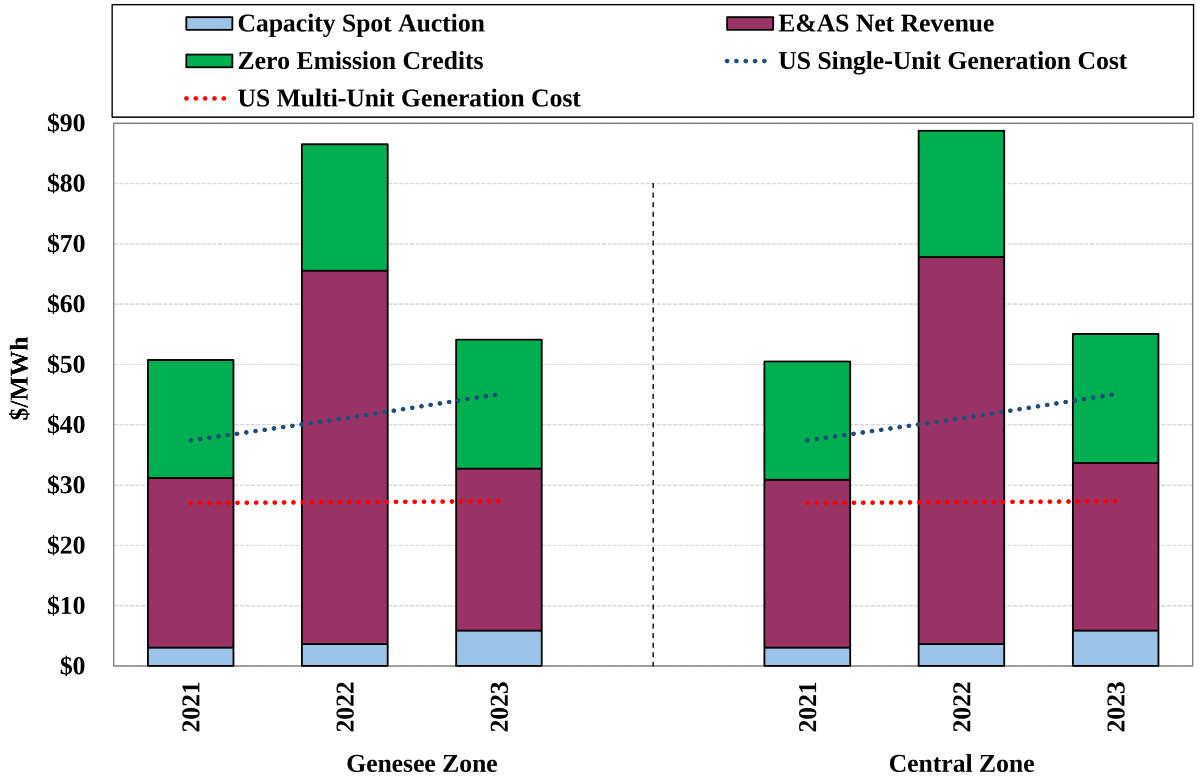
- Nuclear plants are scheduled day-ahead and only sell energy and capacity.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two percent and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[404]
- 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 2021 through 2022.[405]
- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[406] The ZEC price was $19.59/MWh for the period April 2019 to March 2021, $21.38/MWh for the period April 2021 to March 2023, and $18.27/MWh for the period April 2023 to March 2025.

404 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.

405 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See here.

406 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.

Figure A-133: Net Revenue of Existing Nuclear Units
2021-2023



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-31 and Figure A-134: Costs, Performance Parameters, and Net Revenues of Renewable Units

The cost of developing new renewable units, particularly offshore wind and solar PV, has dropped rapidly over the last few years. As such, the estimated investment costs vary significantly based on the year in which the unit becomes operational. Table A-31 shows cost estimates for solar PV, land-based wind and offshore wind units we used for a unit that commenced operations in 2023. Costs are based on NYISO's Renewable Technology Costs study and NREL's Annual Technology baseline (ATB).[407] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for renewable units.

407 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.

Table A-31: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2023) (2023$/kW AC basis)	*Upstate NY*: $1,543	*Upstate NY*: $1,857	*NYC/Long Island* : $4,675
Fixed O&M (2023$/kW-yr)	$26	$36	$128
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: 46% Winter: 2%	Summer: 16% Winter: 34%	Summer: 30% Winter: 50%
Renewable Energy Credits (Nominal $/MWh)	*Onshore Wind and Solar PV:* ***2023*** *- $29.36* ***2022*** *-* $20.67 ***2021*** *-* $22.34 *Offshore Wind:* Calculated using Offshore Wind Solicitation Index REC strike price of $150/MWh ($2026)		

Assuming the operating and cost parameters shown in the table above, Figure A-134 shows the net revenues and the estimated CONE for each of the units during years 2021-2023. 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.

Estimated net revenues and the CONE for utility-scale solar PV and land-based wind units 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.[408]

The capacity revenues for solar PV, land-based wind, and offshore wind units are calculated using prices from the spot capacity market. The capacity values of renewable resources are based on the factors (30, 2, and 50 percent for Winter Capability Periods and 16, 46, and 30 percent for Summer Capability Periods for land-based wind, solar PV, and offshore wind, respectively) specified in the March 2023 NYISO Installed Capacity Manual and publicly available offshore wind OREC contracts.[409]

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. Offshore REC (“OREC”) prices were estimated using the average Index REC strike price of

408 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.

409 The capacity value for renewable resources reflect historical default values by technology from NYISO’s ICAP manual for the years shown here. Beginning in the 2024/25 capability year, resources’ capacity value in all months will be determined by the new Capacity Accreditation process (see here).

recently announced Offshore Wind procurement with expected commercial operation date in 2026, converted to dollars of the year shown.[410] [411]

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 this is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.[412] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[413]

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 financing for renewable projects.[414]

- Our estimated CONE for renewable generators assumes a 2 percent annual escalation of revenues after Year 1.

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410 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 2023 Compliance Year was $29.36/MWh.

411 See NYSERDA press release for 2023 Offshore Wind Solicitation, available here.

412 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.

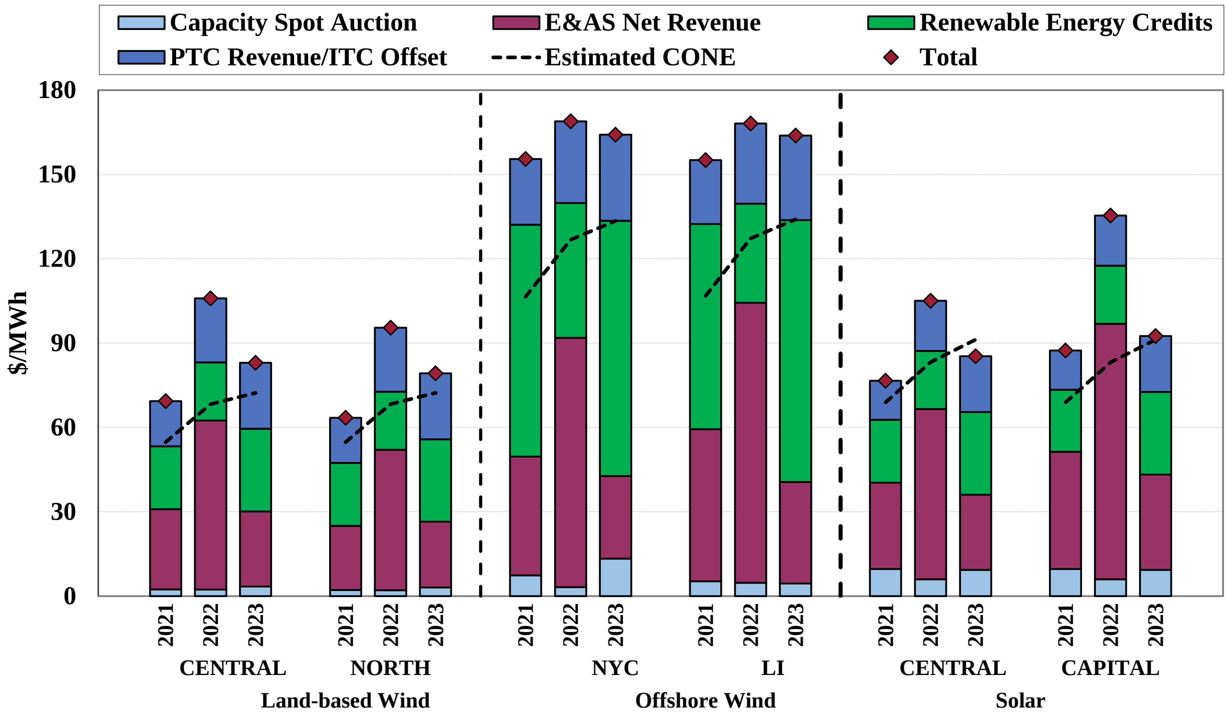
For offshore wind, the ITC is 30 percent of the eligible investment costs for projects that commence construction before 2026. The safe harbor period for the projects is up to ten years. Consequently, we assumed 30 percent ITC for offshore wind projects.

The Production Tax Credit available to land-based wind projects was 100 percent for projects beginning construction before 2017 and 80 percent in 2017. As the developers of land-based wind can safe harbor their investments for a maximum of four calendar years and receive PTC, we assumed an 80 percent PTC for projects entering in service in 2021. 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.

413 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.

414 See Norton Rose Fulbright Cost of Capital: 2024 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 2020 Demand Curve Reset. For 2023, we calculate an ATWACC of 8.7 percent for wind, 8.2 percent for solar, and 9.3 percent for merchant storage.

Figure A-134: Net Revenues of Solar, Land-based Wind and Offshore Wind Units
2021-2023



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-135: 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 six 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-135 assumes that 100 percent of the battery's capacity is offered as day-ahead reserves, which was the highest-revenue strategy in the period 2021-2023.
- Capacity credit for a four-hour storage resource is based on the final capacity accreditation factors (CAFs) for the 2024/25 capability year. The CAF for a four-hour battery is 68.84 percent in New York City and 78.94 percent in Long Island. The CAF

for a six-hour battery is 91.92 percent in New York City and 91.53 percent in Long Island.

- Cost assumptions are based on the 2023 NREL ATB with regionalization factors based on the 2021 Outlook study. Assumed capital costs for a four-hour battery in 2023 are $2,370 per kW in NYC, $2,046 per kW in Long Island, and $1,909 per kW upstate. Assumed capital costs for a six-hour battery in 2023 are $3,327 per kW in NYC, $2,873 per kW in Long Island, and $2,681 per kW upstate. We assume a 20 year project life and merchant cost of capital with after-tax WACC of 9.3 percent in 2023.[415]
- 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.[416] 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-135.

Figure A-135 shows the net revenues and the estimated CONE for each of the units during years 2021-2023. 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.[417]

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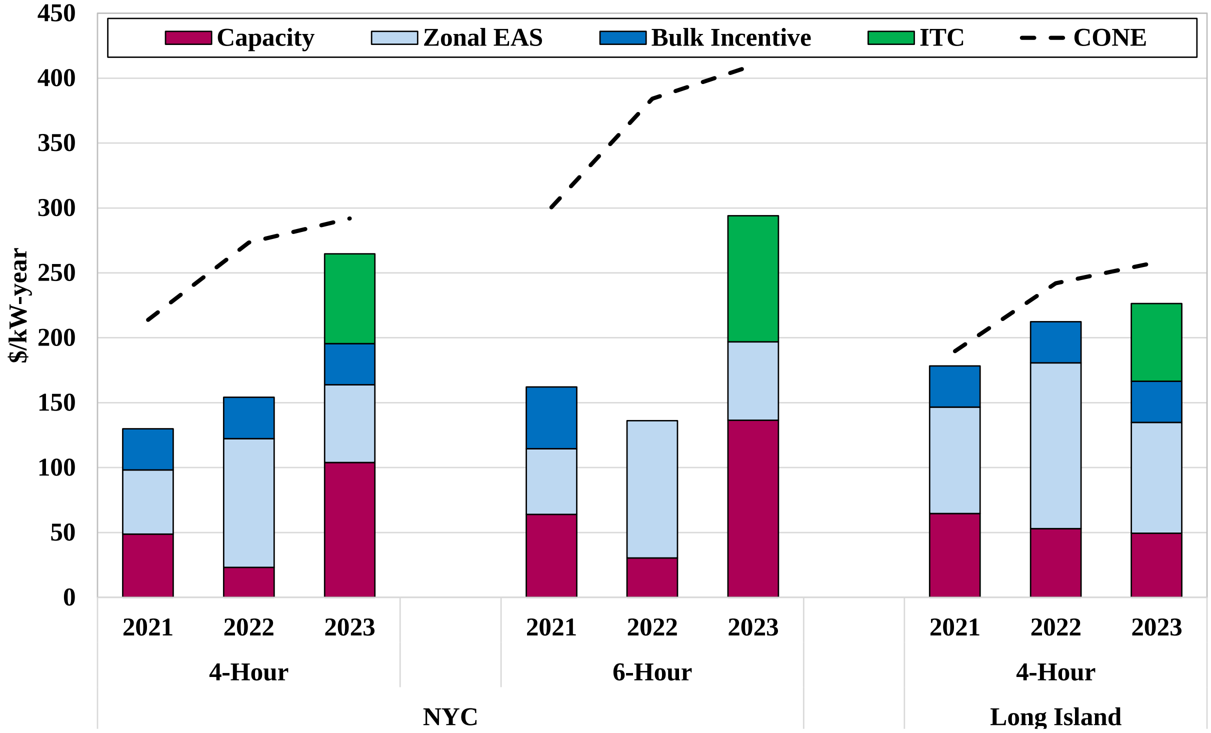
415 See description of our methodology for estimating cost of capital in Section C.

416 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.

417 In addition to revenues from capacity, E&AS, and Bulk Incentive, we show theoretical revenues from the ITC, which is available starting in 2023, and the impact that these additional revenues would have had on units had the ITC been available in previous years.

Figure A-135: Net Revenues and CONE of Energy Storage Units[418]
2021-2023



418 Capacity revenues are shown for each calendar year in Figure A-135. In Figure 6 of Section III.A, capacity revenues for each capability year (May through April) are shown.

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.

The NYISO 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.[419]

- 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.[420]

- 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.[421] 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.

419 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

420 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.

421 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.

- 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 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.

The 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 Participation Model – This project, which is awaiting FERC approval, would allow individual large consumers and aggregations of consumers to participate more directly in the market.[422] This will enable resources to better reflect duration limitations in their offers, payments, and obligations. The NYISO will retire both the DSASP and DADRP programs once the DER Participation Model is implemented. Current DSASP and DADRP resources will be required to either transition to the DER Participation Model or withdraw from the market.

This section evaluates the performance of the existing programs in 2023 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. Future reports will examine the performance of the programs that are currently under development.

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.

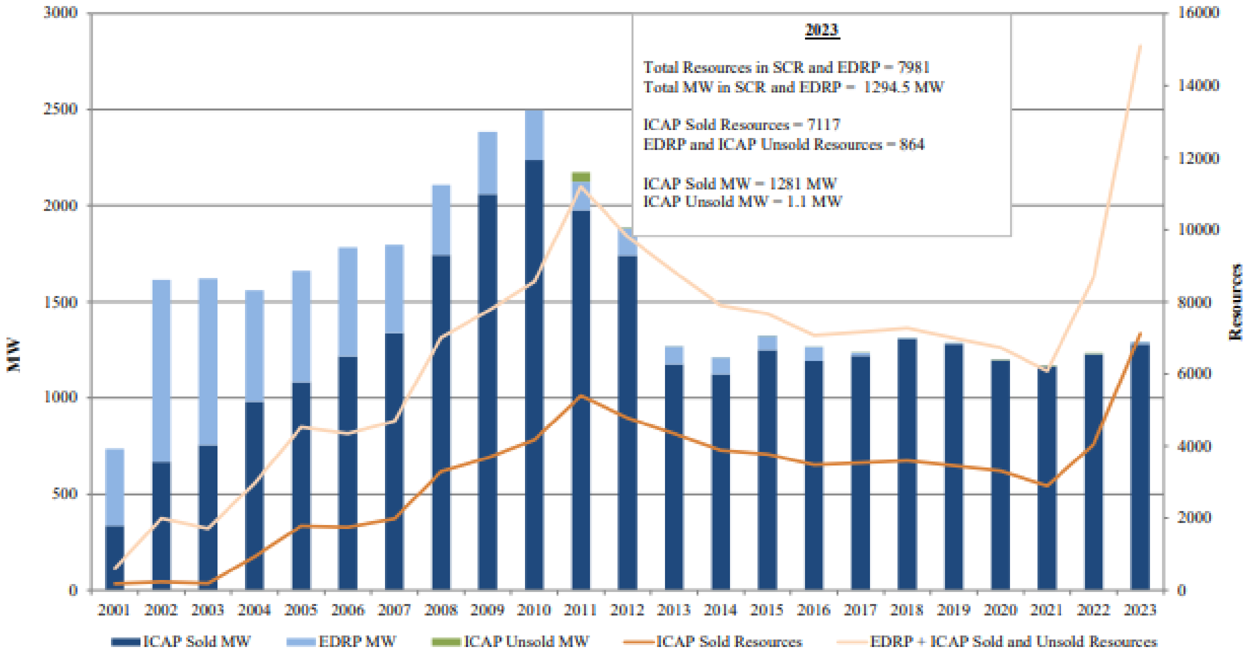
422 The NYISO submitted a filing with the Commission on June 1, 2023 for approval of tariff provisions enabling the participation of DER in the markets for Q3 2023. This received a Deficiency Notice, so NYISO submitted a filing on February 13, 2024 to address the Commission's concerns and seeking approval by April 15, 2024. If approved, the DER Participation Model will be deployed in mid-2024.

Figure A-136: Registration in NYISO Demand Response Reliability Programs

Figure A-136 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2023 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 and SCR resources in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

SCR resources accounted for nearly all of the total enrolled MWs in the reliability-based program in recent years, as this allowed them to earn revenue from the capacity market. The Expanding Capacity Eligibility market rules went effective on May 1, 2021. All SCR resources are required to have a 4-hour duration and their UCAP MWs reflect a Duration Adjustment Factor of 90% set currently for 4-hour resources. [423]

Figure A-136: Registration in NYISO Demand Response Reliability Programs [424]
2001 – 2023



423 See Section 4.1.1 of ICAP Manual for more details.

424 This figure is excerpted from *NYISO 2023 Annual Report on Demand Response Programs*, February 28, 2024, available at: www.nyiso.com/demand-response under *"DR08 - NYISO Semi-Annual Demand Response Report*."

B. Economic Demand Response Programs

The NYISO offers two economic demand response programs.[425] First, the DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to generation supply offers, currently subject to the Monthly Net Benefit Offer Floor.[426] 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. Given that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is doubtful.

Second, the DSASP program allows demand response resources to provide ancillary services. This program has the potential to increase the amount of resources that provide operating reserves and regulation services, 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 415 MW of operating reserves.

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

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425 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 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.

426 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.

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.

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. The 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-32 summarizes the reliability demand response events in 2023. 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. In 2023, the NYISO only activated TDRP once in response to Transmission Owner requests for the sub-load pocket J3 in New York City.

Table A-32: Summary of Reliability Demand Response Activations
2023

DR Program	Event Date	Start Time	End Time	Event Zone	Obligated ICAP MW	# of 5-Minute Intervals w/ Scaricity Pricing Triggered
TDRP	8/21/2023	13:00	19:00	J3	67.4	N/A