2018 State of the Market Report For the New York ISO Markets

POTOMAC ECONOMICS

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EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit ("MMU"), our Core Functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending 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. The 2018 State of the Market Report presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2018. This executive summary provides an overview of market outcomes and highlights and discussion of recommended market enhancements.

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 generation to ensure that resources are started and dispatched each day to meet the system's demands at the lowest cost. These markets also provide competitive incentives for resources to perform efficiently and reliably.

The energy and ancillary services markets are supplemented by the installed capacity market, which provides incentives to satisfy NYISO's planning reliability criteria over the long-term by facilitating efficient investment in new resources and retirement of older uneconomic resources.

Key Developments and Market Highlights in 2018

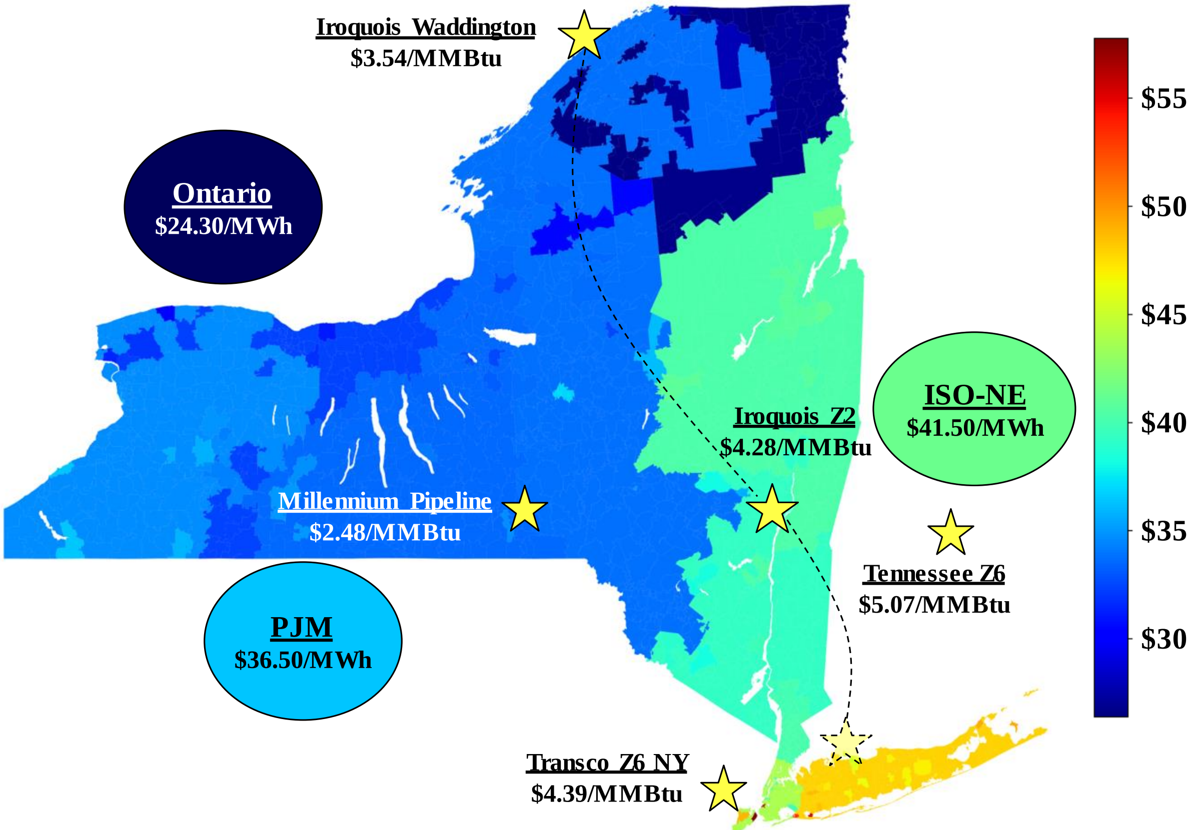
The NYISO markets performed competitively in 2018 because the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were generally effective in limiting conduct that would raise energy prices above competitive levels. Market results and trends are summarized below.

Natural Gas Prices and Load Levels

Natural gas prices and load levels are two key drivers of market outcomes. Average gas prices rose 21 to 47 percent across the state from 2017 to 2018, although a cold spell in early January accounted for most of the increase. During the cold spell, the Transco Zone 6 (NY) gas index price reached a record high of $140 per MMbtu. Excluding January, average gas prices increased only 2 to 8 percent in 2018. Gas price spreads between western and eastern New York declined from 2017 to 2018, which helped reduce west-to-east congestion on the electric transmission system in upstate New York.

Loads rose notably in 2018 from unusually low levels in 2017. The annual peak load was just under 32 GW, up 7 percent from 2017. Average load levels rose 3 percent in 2018 and led to more congestion in New York City and Long Island during the summer.

Day-Ahead Energy, Natural Gas Prices, and Congestion in 2018



Energy Prices and Transmission Congestion

Average energy prices increased 23 to 36 percent across the state from 2017 to 2018, driven primarily by increased load levels and higher natural gas prices in 2018. A strong relationship between energy and natural gas prices is expected in a well-functioning, competitive market because natural gas-fired resources are the marginal source of supply in most intervals.

Transmission congestion and losses led real-time prices to vary from an average of $27 per MWh in the North Zone to $49 per MWh in Long Island in 2018. Congestion revenues collected in the day-ahead market rose 21 percent from 2017, totaling $501 million in 2018. The following transmission corridors accounted for most of the congestion:

- Central-East Interface – 32 percent
- New York City – 18 percent
- Long Island – 16 percent
- Northern-to-central New York – 11 percent
- West Zone (flowing east) – 10 percent

Transmission bottlenecks became more significant in New York City in 2018 because of several lengthy 345kV transmission outages. These outages included the B and C lines between New Jersey and New York City and the 71 line between upstate and New York City.

Installed Capacity Market

Capacity prices continued to be very low because of significant capacity surpluses throughout the state. As result, investment in the new gas turbines that are the demand curve proxy units would not be economic. Spot capacity market prices in the 2018/19 Capability Year produced less than half of the capacity revenues needed to cover the proxy units' entry costs:

- Outside Southeast New York (Zones A-F) – 24 percent
- Lower Hudson Valley (Zones G-I) – 47 percent
- New York City (Zone J) – 38 percent
- Long Island (Zone K) – 34 percent

Long Run Investment Incentives

Markets provide signals that motivate participants to invest in new resources, retire older units, and/or maintain their existing generating units. These signals can be measured by the net revenues generators receive in excess of their production costs. Net revenues increased for most new and existing generators in 2018 because of higher gas prices and summer load levels. We summarize below the results for various types of resources:

New Gas Turbines. There are no areas where investment in a new Frame 7 gas turbine would be economic because of the large capacity surpluses that currently exist throughout the state.

Existing Steam Turbines. Some existing steam turbine units may not be profitable to operate in New York City and Long Island. The decisions by owners of individual steam turbine units to retire in the coming years will likely be based on whether they: are under long-term contracts, have high site-specific costs, or face extraordinary repair costs because of forced outages. The retirement of one or more steam turbines would reduce the current capacity margins and increase net revenues for the steam turbines that remain in service.

Repowering Incentives. Although capacity prices are very low, there are some locations where a new peaking unit would be more profitable to operate than an existing steam turbine. We also find that the implementation of several of our recommendations to enhance the operating reserve markets would help shift investment incentives toward newer more flexible technologies. (See Section VIII.D and Recommendations #2017-1, #2017-2, #2016-1, and #2016-2 for additional details.) Given the large infusion of intermittent renewables that is expected in the coming years, it is important to improve the investment incentives for suppliers to build and maintain resources with flexible characteristics.

Existing Nuclear and New Renewables. Investment incentives for existing nuclear units and potential new renewable projects currently depend primarily on state and/or federal subsidies. The cost of reducing CO_2 emissions varies widely from: a) developing new renewables; b) retaining existing nuclear generation, or c) developing new flexible and fuel-efficient gas-fired generation. This underscores the importance of relying on technology-neutral mechanisms to encourage emission reductions such as a cap-and-trade carbon market or a carbon tax. Resource-specific subsidies are inferior because they create substantial economic risk for suppliers whose investment and retirement decisions are based on market expectations. At the same time, resource-specific and technology-specific subsidies increase the system-wide costs of achieving emission reduction objectives compared with technology-neutral market mechanisms.

Real-Time Market Operations and Market Performance

We evaluate several aspects of market operations, focusing on scheduling efficiency and real-time price signals, particularly during tight operating conditions. Efficient prices are important because they reward resources for performing reliably during tight real-time conditions.

Performance of Operating Reserve Providers

Efficient performance incentives encourage investment in resources with flexible operating characteristics in areas where they are most valuable. Over the coming decade, performance incentives will become more critical as the entry of new intermittent renewable generation requires more complementary flexible resources. We evaluated two aspects of how market outcomes were affected by the performance of operating reserve providers.

First, we analyzed the performance of gas turbines ("GT") in responding to start-up instructions in the real-time market. Although there were notable improvements in 2018, there was still a wide range in the performance of individual units whose reserve market compensation was unaffected by their performance. Consequently, some gas turbines that almost never performed as instructed still managed to earn most of their revenue from the sale of operating reserves. (See Recommendation #2016-2)

Second, we evaluated how the availability and expected performance of operating reserve providers affected the costs of congestion management in New York City. The availability of reserves allows the operator to increase transmission flows on certain facilities, thereby increasing the utilization of the transmission system. However, operating reserves are not compensated for helping manage congestion, which can lead to inefficient scheduling in the real-time market and inefficient investment incentives for gas turbines that can reduce congestion. Efficient incentives for investment in peaking resources has become particularly important since the DEC's proposed peaker rule could lead a large share of peakers in New York City to retire. We recommend compensating resources for this value. (See Recommendation #2016-1)

Market Performance under Shortage Conditions

Although shortage conditions are infrequent, their impact on incentives is substantial. Most shortages are transitory as flexible generation ramp in response to changes in load, external interchange schedules, and other system conditions. Brief shortages provide strong incentives for resources to provide flexibility and perform reliably, and shortage pricing usually accounts for a significant share of the net revenues that allow a generator to recoup its capital investment costs. Efficient shortage pricing in operating reserve and energy markets should reflect the increase risk of load shedding when supply is not sufficient to satisfy all market requirements.

The operating reserve demand curves in New York, which determine the shortage pricing, are likely set well below the expected cost of load shedding when the market is short of operating reserves. This concern has become more acute after PJM and ISO New England implemented Pay-for-Performance (“PFP”) rules in June 2018. The new rules provide strong incentives to schedule transactions to PJM and ISO-NE during reserve shortages. The first PFP event occurred on September 3 when ISO-NE experienced 30-minute reserve shortages, resulting in strong incentives (>$3,000/MWh). This led to 30-minute reserve shortages in New York, which were managed partly through out-of-market actions, since the NYISO’s operating reserve demand curves were not sufficiently high to schedule available resources. We recommend the NYISO consider rule changes to help maintain reliability and provide appropriate incentives during shortage conditions and avoid out-of-market actions. (See Recommendation #2017-2)

Transmission shortages occurred in roughly 4 percent of intervals in 2018, accounting for the majority of shortage pricing incentives. We found that the correlation between the severity and prices during transmission shortages has been greatly improved following the revision of the transmission shortage pricing process in June 2017. This has made congestion more predictable and reduced real-time price volatility. Nonetheless, we observed unnecessarily high shadow prices during some minor transmission shortages, so additional enhancements are needed to improve the correlation of shadow prices and shortages. Therefore, we recommend the NYISO develop constraint-specific transmission demand curves that vary according to the importance, severity, and/or duration of a transmission shortage. (See Recommendation #2015-17)

Drivers of Transient Real-Time Price Volatility

Price volatility can provide efficient incentives for resource flexibility, although unnecessary volatility imposes excessive costs on market participants. Price volatility is an efficient signal when it results from sudden changes in system conditions that cannot be predicted by the NYISO (e.g., a generator or line trips offline). However, unnecessary price volatility can occur when the NYISO’s market models do not incorporate an observable factor that affects market conditions significantly. Hence, it is important to identify the causes of volatility. We performed an evaluation of the drivers of real-time price volatility in 2018 and found the following two categories continued to be most significant:

- *Resources scheduled by RTC* – The RTC model schedules external transactions and gas turbines on a 15-minute basis without considering how large changes in output will affect the market on a 5-minute basis, which can lead to brief shortages of ramp-able capacity.
- *Flow changes resulting from non-modeled factors* – Includes volatile loop flows and frequent flow variations on Phase Angle Regulator ("PAR")-controlled lines (primarily on the A, J, K, and 5018 lines between New York and New Jersey). These flow changes are caused by inaccurate PAR modeling assumptions and other unforeseen variations in non-modeled flows that lead to acute reductions in the amount of transfer capability that is available to transactions scheduled by the NYISO.

These changes can create brief shortages and over-generation conditions when flexible generators cannot ramp quickly enough to compensate for the change, leading to sharp changes in energy prices and congestion. In this report, we discuss potential solutions and recommend improvements to address these issues. (See Recommendations #2012-13 and #2014-9)

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. While the CTS process is capable of providing significant benefits under current conditions, the benefits of having flexible price-responsive interchange between markets will increase as intermittent resources are added to New York and neighboring systems.

We found that overall performance of CTS improved modestly from 2017 to 2018. The improvement resulted partly from better price forecasting of the NYISO and ISO-NE at the interfaces. Notwithstanding the improvement, CTS is still limited to relatively small (300 MW maximum) adjustments in net interchange every 15 minutes, and it has significantly greater potential to help the three markets balance short-term variations in supply.

Participation in CTS was more robust at the New England interface than at the PJM interface. In 2018, an average of 254 MW of price-sensitive transaction bids were offered at the PJM border, compared to 612 MW at the New England border. The large difference in performance of the two CTS processes is likely the result of large fees and uplift costs imposed on CTS transactions at the PJM interface. In contrast, fees are not imposed on transactions at the ISO-NE interface. We found that firms scheduling at the PJM interface require larger price spreads between markets before they will schedule power to flow across the interface. These results demonstrate that imposing large transaction fees on a low-margin trading activity dramatically reduces liquidity and the overall efficiency of the CTS process. Therefore, we recommend that NYISO work with other parties to eliminate these charges at the border. (See Recommendation #2015-9)

We performed an evaluation of factors that contribute to forecast errors by RTC, which is used to schedule CTS transactions and other external transactions and fast-start units. We identify factors that contribute to divergence between RTC and RTD, concluding that they are primarily the same factors that we have identified as contributors to transient price volatility. Hence, the evaluation provides additional support for the recommendations cited above to address transient price volatility. (See Recommendation #2012-13 and #2014-9)

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 flows regardless of whether it is efficient to do so. 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"). The operation of these lines (in accordance with the wheeling agreements) ***increased*** production costs by an estimated $16 million in 2018.

The ConEd-LIPA wheeling agreement continues to use the 901 and 903 lines in a manner that raises production costs inefficiently. Hence, the 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 Recommendation #2012-8.)

Operations of PAR-Controlled Lines between New York and PJM

The PARs associated with the old ConEd-PSEG wheeling agreement (which was terminated at the end of April 2017) are now incorporated into the NY-PJM AC interface for interchange scheduling and the M2M process. These changes have led to more efficient utilization of some of these PAR-controlled lines. However, opportunities for improved utilization remain as they were generally operated well below their operational limits. (See Section IX.F)

Out-of-Market Actions and Guarantee Payment Uplift

Guarantee payments to generators more than doubled to $77 million in 2018. Most of the increase occurred in New York City and Long Island. In New York City, increased supplemental commitment for N-1-1 requirements in the load pockets accounted for over $26 million of guarantee payment uplift. We have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals. (See Recommendation #2017-1)

On Long Island, nearly $10 million of local uplift was paid to high-cost peaking resources when they were deployed out-of-merit to manage congestion in the 69 kV network and voltage needs on the East End of Long Island on high load days. We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets, which would be more efficient and would provide better incentives for new investment. (See Recommendation #2018-1)

The NYISO also frequently took out-of-market actions to manage congestion on the 115 kV system in the other regions. In 2018, OOM actions were taken to manage congestion on the 115 kV facilities on:

- 260 days for the West Zone;
- 130 days in the Capital Zone; and
- 81 days for flows from the North Zone.

Over the last year, the NYISO has incorporated nearly all 115 kV constraints that bind in upstate New York into the market software. This has helped reduce out-of-market actions, manage congestion more efficiently, and improve investment incentives.

Capacity Market

The capacity market continues to be an essential element of the NYISO electricity markets, providing economic signals needed to facilitate market-based investment to satisfy the state's planning requirements. This report identifies several areas for improvement in the capacity market, including the following:

Locational Capacity-Pricing Enhancements. The current capacity market design is generally based on the NYISO's planning criteria. However, the prices and reliability value provided by resources are poorly aligned in several locations under the current framework. Furthermore, it will be difficult for the current capacity market to adapt to changes over the coming decade, including large-scale retirements and new entry, the introduction of new intermittent generation, energy storage, and new transmission. We have recommended a capacity pricing framework that is simpler and will produce prices that are better aligned with NYISO's planning criteria. 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 framework would be easier to administer, more adaptable to changes in system conditions, and would reduce the overall costs for maintaining reliability. (Recommendation #2013-1c)

Transmission Investment. New transmission enhances reliability and helps satisfy planning criteria, but most transmission projects are not eligible to be compensated for these benefits through the capacity market. We estimated the capacity payments that would have been received by a recently-built transmission project into Southeast New York and found it could have recouped 51 percent of its annualized cost of investment from the capacity market if efficient capacity payments were available to transmission projects. We recommend creating a financial capacity transfer right to provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives. (Recommendation #2012-1c)

Mitigation Rules. This report recommends several modifications to the buyer-side mitigation rules to ensure that they do not unnecessarily impede new investment. This includes enhancements to the mitigation exemption test forecast methodologies and refinements to the competitive entry exemption, the test procedure for very small (<2 MW) projects, and the Part A test criteria. (See Recommendations #2013-2d, #2018-2, #2018-3, and #2018-4.)

Economic Transmission Planning

The NYISO estimates the economic benefits that would result from a new transmission project in the CARIS study evaluation and in the Public Policy Transmission Need evaluation processes. These estimates are used to rank projects and ultimately determine whether a project provides sufficient benefits to justify the costs of the project. We recommend several changes to the NYISO's estimation of benefits (see Recommendation #2015-7), including:

- Inclusion of Capacity Market Benefits – Excluding these benefits undervalues transmission projects that could make significant contributions to satisfying the NYISO's planning reliability requirements.
- Modeling Economic Retirements and New Entry – Scenarios should recognize that if a new transmission project moves forward, it will likely affect the retirement and/or entry decisions of other resources.
- Modeling Reserve Requirements and Local Reliability Needs – As zero-marginal cost resources are added to the electrical grid, it will be increasingly important to consider where local reserve needs may still lead to operation of conventional resources, but these are not considered in the GE MAPS model that is used to assess benefits of transmission.

Overview of Recommendations

The NYISO electricity markets generally performed well in 2018 and the NYISO has continued to improve its operation and enhance its market design. Nonetheless, our evaluation identifies a number of areas of potential improvement, so we make recommendations that are summarized in the following table. The table identifies the highest priority recommendations and those that the NYISO is addressing in the 2019 Project Plan or in some other effort. In general, the recommendations that are designated as the highest priority are those that produce the largest economic efficiencies by lower the production costs of satisfying the system's needs or improving the incentives of participants to make efficient long-term decisions.

Twenty-one recommendations are presented in six categories below. Most of these were made in our 2017 SOM report, but Recommendations #2018-1 to #2018-4 are new in this report. A detailed discussion of each recommendation is provided in Section XI.

Number	Section	Recommendation	Current Effort	High Priority
Energy Market Enhancements - Pricing and Performance Incentives				
2018-1	V.B	Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions and develop associated mitigation measures.		
2017-1	VIII.D, IX.H	Model local reserve requirements in New York City load pockets.	✓	✓
2017-2	VIII.D, IX.B	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	✓	✓
2016-1	VIII.D, IX.D	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		
2016-2	VIII.D, IX.D	Consider means to allow reserve market compensation to reflect actual and/or expected performance.	✓	
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.		
2015-16	IX.B	Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.		
2015-17	IX.B	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	✓	
Energy Market Enhancements – Market Power Mitigation Measures				
2017-3	IX.B	Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.		
2017-4	III.B	Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.		
Energy Market Enhancements - Real-Time Market Operations				
2014-9	VI.D, IX.G	Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.		
2012-8	IX.E	Operate PAR-controlled lines between New York City and Long Island to minimize production costs and create financial rights that compensate affected transmission owners.		
2012-13	VI.D, IX.G	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.		
Capacity Market – Market Power Mitigation Measures				
2018-2	III.C	Modify the Competitive Entry Exemption to allow contracts that are determined to be competitive and non-discriminatory.		
2018-3	III.C	Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.		

Number	Section	Recommendation	Current Effort	High Priority
2018-4	III.C	Develop tariff provisions to perform Mitigation Exemption Tests outside the Class Year process for resources that are smaller than 2 MW.		
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
Capacity Market – Design Enhancements				
2013-1c	VII.D	Implement locational marginal pricing of capacity (“C-LMP”) that minimizes the cost of satisfying planning requirements.		✓
2012-1a	VII.D	Establish a dynamic locational capacity framework that reflects potential deliverability, resource adequacy, and transmission security requirements.		
2012-1c	VII.C	Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.		
Planning Process Enhancements				
2015-7	VII.E	Reform the CARIS process to better identify and fund economically efficient transmission investments.		

I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2018.[1] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

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

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to reliably meet the system's demands at the lowest cost.

The coordination provided by the markets is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered. In addition, the markets provide transparent price signals that facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions. Relying on private investment shifts the risks and costs of poor decisions and project management from New York's consumers to the investors.

As federal and state policy-makers promote public policy objectives such as environmental quality through investments in electricity generation and transmission, the NYISO markets provide useful information regarding the likely effects on the power system and cost of production. As policy-makers seek to reduce emissions and reliance on fossil fuels, the NYISO markets provide incentives for both conventional and new resources that help integrate clean energy resources.

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

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

- Simultaneous optimization of energy and operating reserves, 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;
- Operating reserve 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.
- A market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets.
- 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 markets provide substantial benefits to the region by ensuring that the lowest-cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. However, it is important for the markets to continue to evolve to improve alignment between the market design and the reliability needs of the system, to provide efficient incentives to the market participants, and to adequately mitigate market power.

Furthermore, the markets should adapt as the generation fleet shifts from being primarily fossil fuel-based to having higher levels of renewable penetration. Although large-scale changes in the generation fleet result primarily from public policies to reduce pollution and promote cleaner generation, the NYISO markets provide critical incentives for placing new resources where they are likely to be most economical and deliverable to consumers. Hence, Section XI of the report provides a number of recommendations that are intended to achieve these objectives.

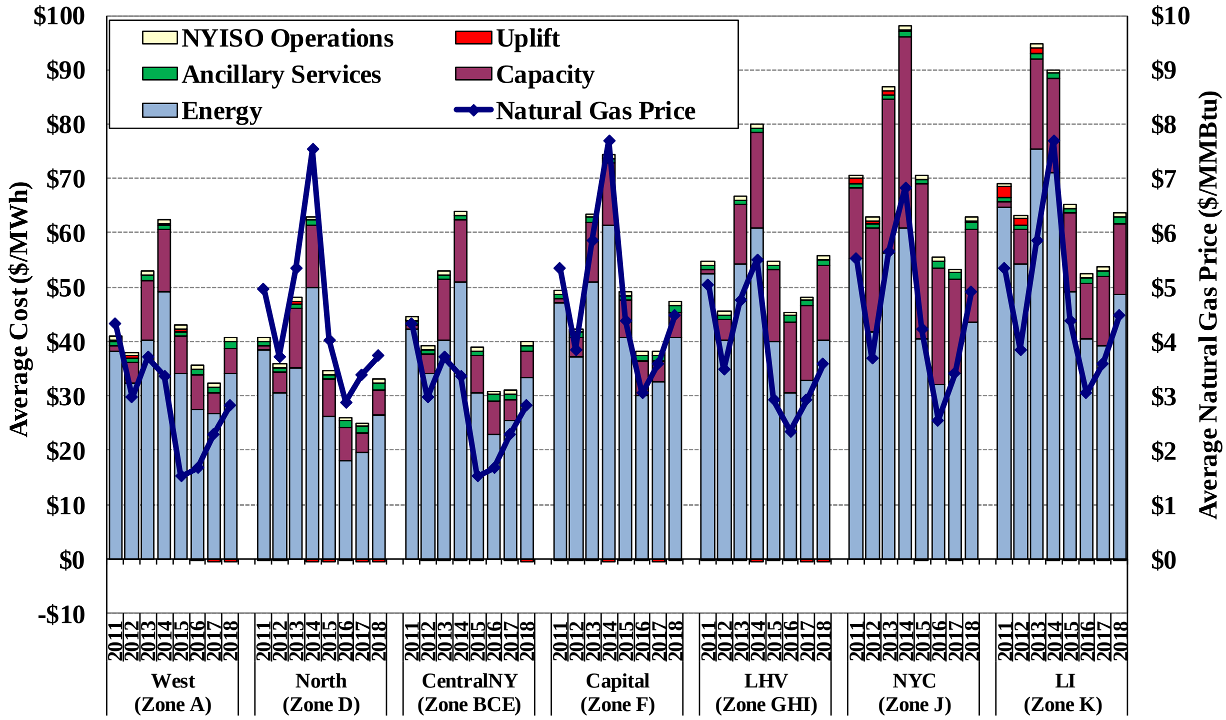
II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2018. It evaluates energy and ancillary service prices, fuel prices, generation and demand patterns, and congestion patterns.

A. Total Wholesale Market Costs

Figure 1 summarizes wholesale market costs over the past eight years by showing the all-in price for electricity, which reflects the average cost of serving load from the NYISO markets. The energy component of this metric is the load-weighted average real-time energy price, while all other components are the costs divided by the real-time load in the area.[2]

Figure 1: Average All-In Price by Region
2011-2018



All-in prices increased significantly in 2018 from the historically low levels seen in 2017. All-in prices ranged from as little as $32 per MWh in the North Zone to $64 per MWh in Long Island. Over the eight years shown, variations in natural gas prices have been the primary driver of variations in the energy component of the all-in price, although changes in congestion patterns have also significantly affected the energy prices at some locations. In 2018, energy prices accounted for 69 to 86 percent of the all-in price in each region.

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

Average energy prices rose 23 to 36 percent from 2017 to 2018. Most of the year-over-year increase resulted primarily from higher natural gas prices in 2018, especially during the severe cold weather during the first half of January 2018.[3] Higher summer load conditions further contributed to increased energy prices in 2018.[4] Natural gas-fired units accounted for most of the increased generation required to meet the higher load levels in 2018.[5]

Capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs. Average capacity costs rose or fell in different regions from 2017 to 2018 as follows:

- Decrease of 1 percent in the Lower Hudson Valley (i.e., Zones G, H, and I) and 2 percent in New York City,
- Increase of 3 percent in Long Island, and
- Increase of 25 percent in Rest of State.

In the Rest of State, capacity price increases were largely driven by reduced imports from neighboring control areas. A steep decline in PJM imports was partially offset by increased imports from Ontario.[6]

B. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. This is expected in a competitive market because most of the marginal costs of thermal generators are fuel costs. Table 1 summarizes fuel prices in 2017 and 2018 on an annual basis, for January alone, and for the remaining eleven months of the year.[7] The table also shows average real-time energy prices in seven regions of the state over the same time periods. A representative gas price index is shown for each region, and the three most commonly burned oil fuel prices are also shown.

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3 Gas supply constraints required many generators to switch fuels during the severe cold weather events in January 2018. See Section B for discussion of fuel price trends and underlining drivers.

4 See Section I.D of the Appendix for discussion of load patterns.

5 See Section I.B of the Appendix for generation mix by quarter.

6 See Section VII.A for additional details about capacity prices.

7 Section I.B in the Appendix shows the monthly variation of fuel prices.

Table 1: Average Fuel Prices and Real-Time Energy Prices
2017-2018

	Annual Average			January Average			Rest-of-Year Average		
	2017	2018	% Change	2017	2018	% Change	2017	2018	% Change
Gas Prices ($/MMBtu)									
Ultra Low-Sulfur Kerosene	$13.53	$16.60	23%	$13.69	$17.08	25%	$13.52	$16.56	23%
Ultra Low-Sulfur Diesel Oil	$11.92	$15.07	26%	$11.71	$14.94	28%	$11.94	$15.08	26%
Low-Sulfur Residual Oil	$8.43	$11.49	36%	$9.05	$10.76	19%	$8.37	$11.55	38%
Millenium East	$2.06	$2.48	21%	$2.92	$3.00	3%	$1.98	$2.44	23%
Transco Z6 (NY)	$2.99	$4.39	47%	$3.82	$18.73	390%	$2.91	$3.09	6%
Iroquois Z2	$3.39	$4.28	26%	$4.66	$14.65	214%	$3.27	$3.34	2%
Tennessee Z6	$3.78	$5.07	34%	$5.41	$17.59	225%	$3.63	$3.93	8%
Energy Prices ($/MWh)									
West (Millen. East)	$26.83	$34.13	27%	$28.46	$66.95	135%	$26.32	$30.33	15%
North (Waddington)	$19.48	$26.50	36%	$27.19	$65.37	140%	$20.27	$23.00	13%
Central NY (Millen. East)	$25.45	$33.40	31%	$30.03	$70.83	136%	$23.43	$29.18	25%
Capital Zone (Iroquois)	$32.65	$40.74	25%	$40.51	$109.34	170%	$29.35	$32.90	12%
Lw. Hudson (Millen. East/Ir	$32.83	$40.36	23%	$38.62	$101.56	163%	$30.24	$33.53	11%
New York City (Transco)	$34.11	$43.63	28%	$38.59	$108.28	181%	$34.84	$38.10	9%
Long Island (Iroquois)	$39.20	$48.58	24%	$41.38	$108.32	162%	$38.28	$41.90	9%

Although much of the energy used by New York consumers is generated by hydro and nuclear units, natural gas units are usually the marginal source of generation that set market clearing prices, especially in Eastern New York. Consequently, energy prices in New York have followed a pattern similar to natural gas prices over the past several years.

The average natural gas prices across the state increased by 21 percent (Millennium East) to 47 (Transco Zone 6 (NY)) percent from 2017 to 2018. The primary driver of this increase was the natural gas scarcity conditions observed during the severe cold weather in first half of January.[8] Natural gas price increases were much less significant in the remaining months. For instance, the average Transco Zone 6 (NY) index price increased 390 percent year-over-year in January 2018 compared to 6 percent year-over-year for February to December 2018.

Gas pipeline congestion patterns were similar to electricity congestion patterns with substantial spreads between Western and Eastern New York in January 2018 and much smaller spreads over the remainder of 2018. Overall, the spreads between regions increased in 2018 relative to 2017. As in recent years, the regional gas price spreads continued to be a key contributor to congestion

8 See Section I.B of the Appendix for more information on the January 2019 Winter Cyclone and Polar Vortex and how these combined to impact natural gas prices.

across the New York power system.[9,10] In particular, the large price spread in January 2018 resulted in high levels of Central-East congestion during that month as many generators in eastern New York switched to burning fuel oil while marginal generators in western New York burned lower priced natural gas and coal.

C. 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.

Table 2 summarizes the annual usage of generation by fuel type from 2016 to 2018, including: (a) the average quantities of generation by each fuel type; (b) the share of generation by each fuel type relative to the total generation; and (c) how frequently each fuel type was on the margin and setting real-time energy prices.[11,12] The marginal percentages sum to more than 100 percent because more than one type of unit is often marginal, particularly when the system is congested.

Table 2: Fuel Type of Real-Time Generation and Marginal Units in New York
2016-2018

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2016	2017	2018	2016	2017	2018	2016	2017	2018
Nuclear	4.7	4.8	4.9	31%	33%	32%	0%	0%	0%
Hydro	2.9	3.2	3.2	19%	22%	21%	47%	43%	44%
Coal	0.2	0.1	0.1	1%	0.4%	1%	1%	1%	1%
Natural Gas CC	5.1	4.6	4.9	33%	31%	32%	68%	77%	77%
Natural Gas Other	1.7	1.2	1.3	11%	8%	9%	30%	32%	42%
Fuel Oil	0.1	0.1	0.2	0.5%	0.4%	1%	3%	2%	3%
Wind	0.4	0.5	0.5	3%	3%	3%	3%	5%	7%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

Gas-fired units accounted for the largest share of electricity production in each year of 2016 to 2018. The share of gas-fired generation increased from 39 percent in 2017 to 41 percent in 2018 mostly due to higher load levels during the summer months.

9 For instance, the Millennium East index exhibited an average discount of 43 percent relative to the Transco Zone 6 (NY) index in 2018 compared to an average discount of 31 percent in 2017.

10 See Section III.B of the Appendix for more on this.

11 Section I.B in the Appendix provides regional breakdowns and describes the methodology that was used to determine how frequently each type of resource was on the margin (i.e., setting the real-time price).

12 Figure A-7 in the Appendix shows generation mix by region by quarter in 2017 and in 2018.

The small changes in generation from nuclear resources (which accounted for slightly more than 30 percent of all generation each year) were driven primarily by variations in the amount of deratings and outages. Coal-fired units produced less than one percent of all output because low gas prices continue to make these units relatively uneconomic and because the Milliken facility is no longer needed for local reliability in the Central Zone following transmission upgrades. Average oil-fired generation increased by over 110 MW from 2017 because of the severe cold weather during the first half of January 2018. High gas prices and flow restrictions during this period led many downstate generators to burn oil for more than one week. We discuss utilization of oil-fired and dual-fuel capacity during the cold spell in more detail in section IX.A.

Gas-fired units and hydro resources were most frequently on the margin in recent years. Higher load levels and increased congestion (particularly in New York City) led gas-fired peakers to be on the margin more often in 2018. Most marginal hydro units have storage capacity, leading their offers to include the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by natural gas prices. Other fuel types set prices much less frequently.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Table 3 shows load statistics for the New York Control Area ("NYCA") since 2010: a) annual summer peak; b) annual winter peak; c) annual average load; and d) number of hours when load exceeded certain levels.

Table 3: Peak and Average Load Levels for NYCA
2010 – 2018

Year	Load (GW)			Number of Hours >		
	Summer Peak	Winter Peak	Annual Average	32GW	30GW	28GW
2010	33.5	23.9	18.7	13	69	205
2011	33.9	24.3	18.6	17	68	139
2012	32.4	23.9	18.5	6	54	162
2013	34.0	24.7	18.7	33	66	145
2014	29.8	25.7	18.3	0	0	40
2015	31.1	24.6	18.4	0	23	105
2016	32.1	24.2	18.3	1	33	163
2017	29.7	24.3	17.9	0	0	43
2018	31.9	25.1	18.4	0	59	167

In 2018, both peak load and average load levels were consistent with levels witnessed in recent years except 2017 (which was unusually mild). The annual peak load level was slightly below

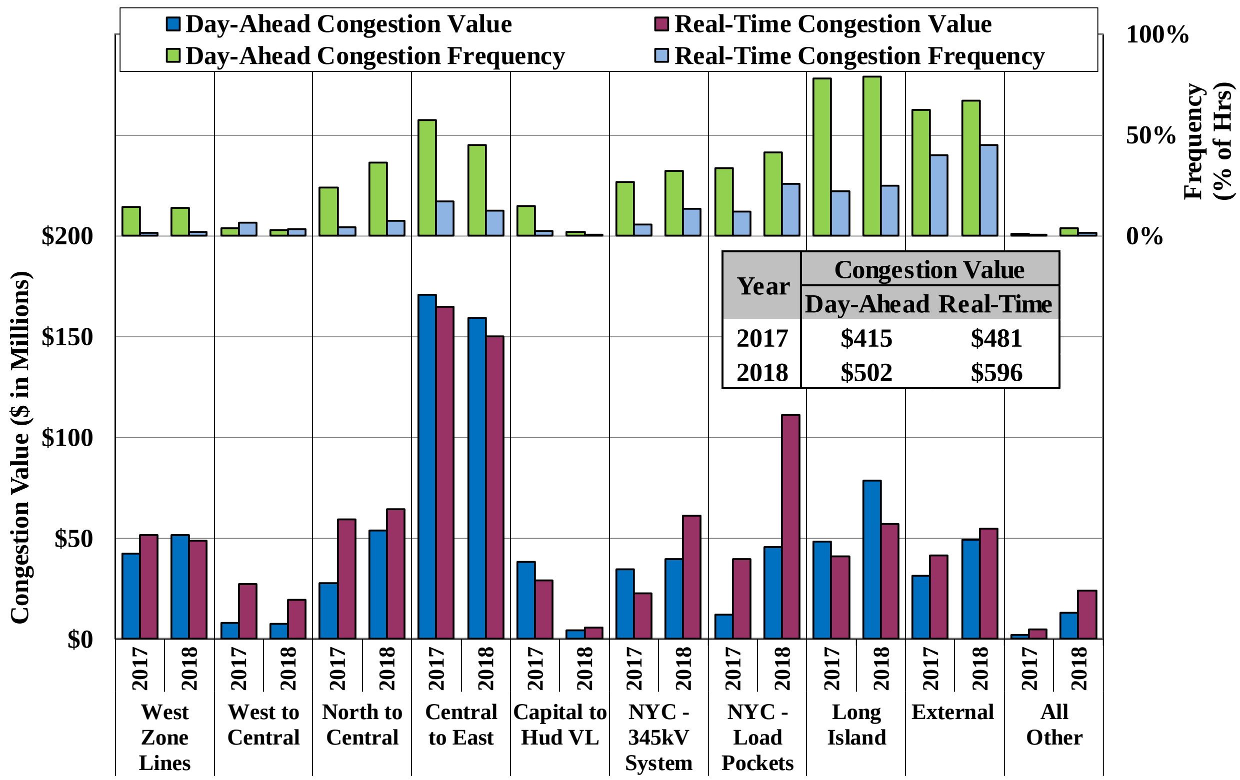
32 GW, rising sharply (by 7 percent) from 2017 because of hotter summer weather. Average load levels also rose by about 3 percent to 18.4 GW due partly to the summer weather.

E. Transmission Congestion Patterns

Figure 2 shows the value and frequency of congestion along major transmission paths in the day-ahead and real-time markets.[13] Although the vast majority of congestion revenues are collected in the day-ahead market (where most generation is scheduled), congestion in the real-time market is important because it drives day-ahead congestion in a well-functioning market.[14]

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path

2017-2018



Year	Congestion Value	
	Day-Ahead	Real-Time
2017	$415	$481
2018	$502	$596

The value of day-ahead congestion rose 21 percent to $502 million in 2018, consistent with higher load levels and natural gas prices. The effects of natural gas prices were particularly significant in the first eight days of January (during a cold spell, the “Bomb Cyclone”) when

13 Section III.B in the Appendix discusses the congestion patterns in greater detail.

14 Most congestion settlements occur in the day-ahead market. Real-time settlements are based on deviations in the quantities scheduled relative to the day-ahead market. For example, if 90 MW is scheduled to flow over an interface in the day-ahead market and 100 MW is scheduled in the real-time market, the first 90 MW settle at day-ahead prices, while the last 10 MW settle at real-time prices.

natural gas prices rose above $140/MMbtu in New York City and day-ahead congestion revenues totaled $59 million (or 12 percent of the annual total).

Transmission outages were another key driver of congestion in some areas. Fewer costly transmission outages reduced congestion across the Central-East interface and from the Capital Zone to the Hudson Valley Zone. On the other hand, more transmission outages helped increase congestion in New York City, on Long Island, from the North Zone to Central New York, and from New York to New England across its primary interface.

Other factors also played an important role in affecting congestion. For example, congestion across the Central-East interface decreased partly because of fewer nuclear unit outages in Lower Hudson Valley and the new entry of the CPV Valley generating facility. Congestion of flows out of the North Zone became more prevalent in the day-ahead market in 2018 because certain 115 kV transmission constraints were modeled starting in May 2018.[15] New York City congestion increased, also attributable to the expiration of the PSEG/ConEd Wheeling agreement in May 2017, which greatly reduced imports from PJM across the PAR-controlled ABC lines.[16]

F. Ancillary Services Markets

Ancillary services and energy scheduling is co-optimized. Part of the cost of providing ancillary services is the opportunity cost of not providing energy when it otherwise would be economic to do so. Co-optimization ensures that these opportunity costs are efficiently reflected in Location Based Marginal Prices ("LBMPs") and reserve prices. The ancillary services markets provide additional revenues to resources that are available during periods when the resources are most economic to provide operating reserves. This additional revenue rewards resources that have high rates of availability. Figure 3 shows the average prices of the four ancillary services products by location in the day-ahead market in each month of 2017 and 2018.[17]

Average day-ahead prices for all reserve products rose in 2018 consistent with higher opportunity costs of not providing energy. As in 2017, the price of the NYCA 30-minute reserves accounted for most of the day-ahead market reserve prices in 2018; however, the 10-minute spinning component increased from 2017 to 2018. Severe cold weather in January, which led to gas supply constraints and high energy prices, contributed to high prices for all

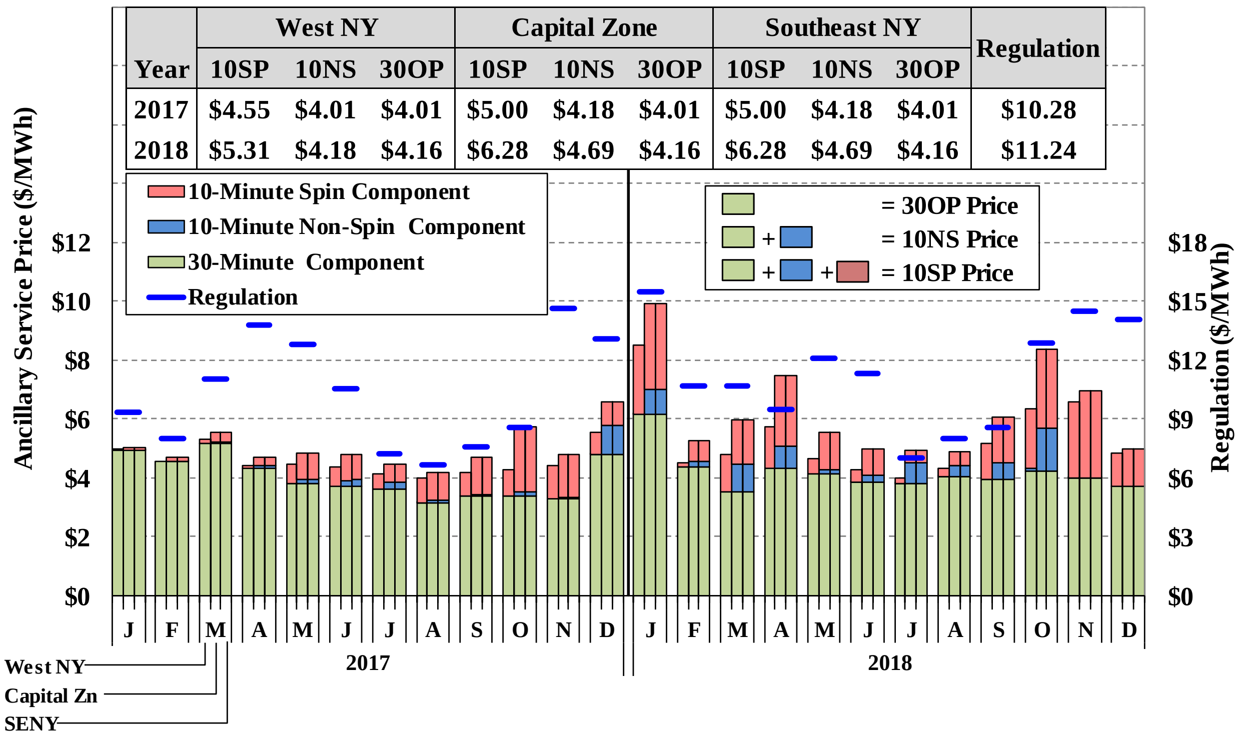
15 The Constraint Reliability Margin ("CRM") values for 115 kV facilities were unnecessarily high (to confirm with approved tariff rules) when the constraints were first modeled, leading to higher congestion costs as discussed in Section V.H in the Appendix. The NYISO filed a tariff change with the FERC to allow the use of lower CRM values for these transmission facilities, effective on December 4, 2018.

16 However, this reduction was partly offset by the increase of the imports across the HTP interface, most likely in response to higher congestion and resulting higher LBMPs in New York City.

17 See Appendix Section I.H for additional information regarding the ancillary services markets and detailed description of this chart.

reserve products. Gas pipeline repairs in April and significant maintenance outages of 10-minute capable generators during the shoulder months led to increases in the prices of 10-minute reserve products. The changes in reserve offer prices in the day-ahead market are discussed further in Section II.D in the Appendix.

Figure 3: Average Day-Ahead Ancillary Services Prices
2017-2018



	West NY			Capital Zone			Southeast NY			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
2017	$4.55	$4.01	$4.01	$5.00	$4.18	$4.01	$5.00	$4.18	$4.01	$10.28
2018	$5.31	$4.18	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$11.24

The average regulation prices also rose from 2017 due in part to higher opportunity costs and more outages of regulation suppliers. As observed during the shoulder (particularly Fall) months, lower load periods exhibited higher regulation prices in 2018. The amount of online generating capacity is relatively low during these months, and more generators are on maintenance outages, thereby reducing the supply of regulation.

III. COMPETITIVE PERFORMANCE OF THE MARKET

We evaluate the competitive performance of the markets for energy, capacity, and other products on an on-going basis. This section discusses the findings of our evaluation of 2018 market outcomes in three areas: Subsection A evaluates patterns of potential economic and physical withholding by load level in Eastern New York; Subsection B analyzes the use of market power mitigation measures in New York City and in other local areas when generation is committed for reliability; Subsection C discusses developments in the capacity market and the use of the market power mitigation measures in New York City and the G-J Locality in 2018.

A. Potential Withholding in the Energy 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 typically be more sensitive to withholding and other anticompetitive conduct under high load conditions. 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 transmission-constrained areas.

In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate 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.[18]

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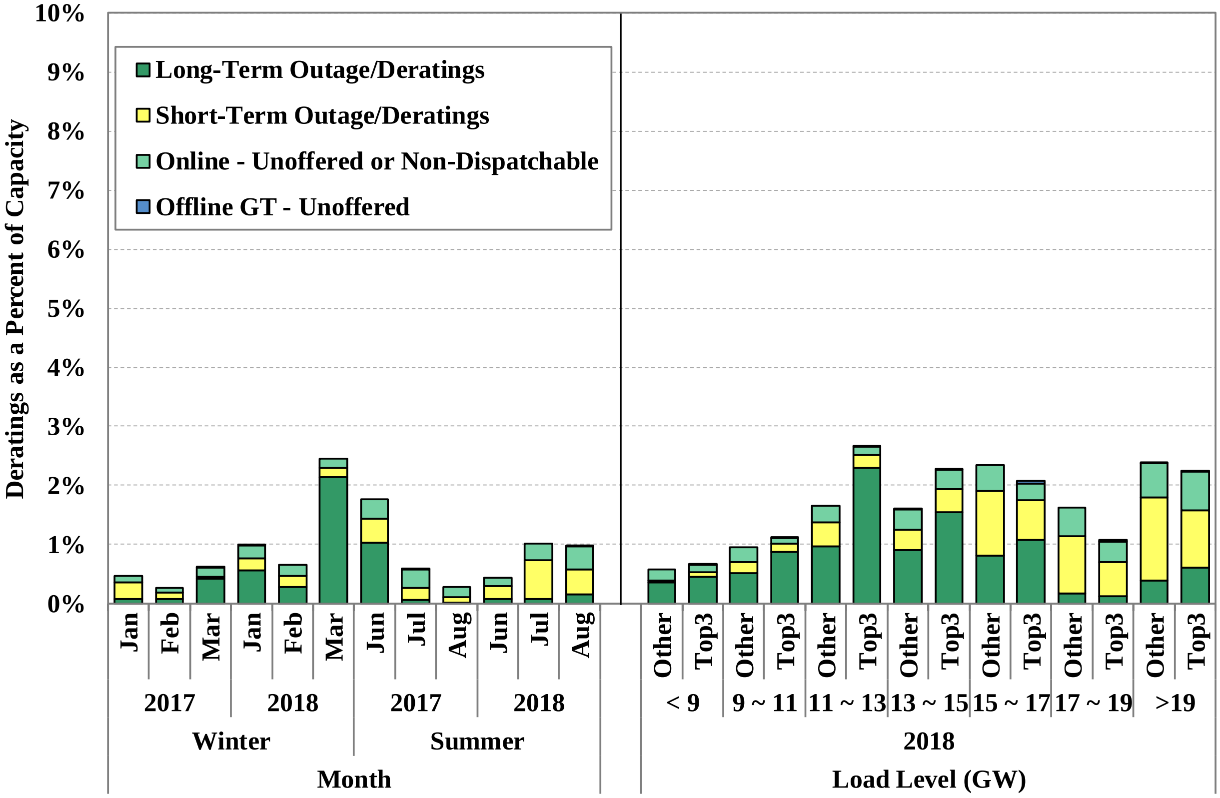
18 The output gap calculation excludes capacity that is more economic to provide reserves. In this report, the Mitigation Threshold refers to the threshold used for statewide mitigation, which is the lower of $100 per MWh or 300 percent of the reference level. Lower Threshold 1 is the 25 percent of the reference level, and Lower Threshold 2 is 100 percent of the reference level.

Figure 4 and Figure 5 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[19] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

Figure 4: Unoffered Economic Capacity in Eastern New York
2017-2018



Derated and unoffered economic capacity averaged 1.4 percent of total capacity (DMNC) in NYCA and 1.6 percent in Eastern New York in 2018, both of which were modestly higher than 2017 levels.

The pattern of generator outages and deratings in Eastern New York in 2018 was consistent with patterns observed in 2017. Most derated and unoffered capacity resulted from long-term outages during shoulder months in the spring and autumn. Unoffered economic capacity was higher in the summer of 2018 relative to 2017 primarily because of a few notable outages.[20]

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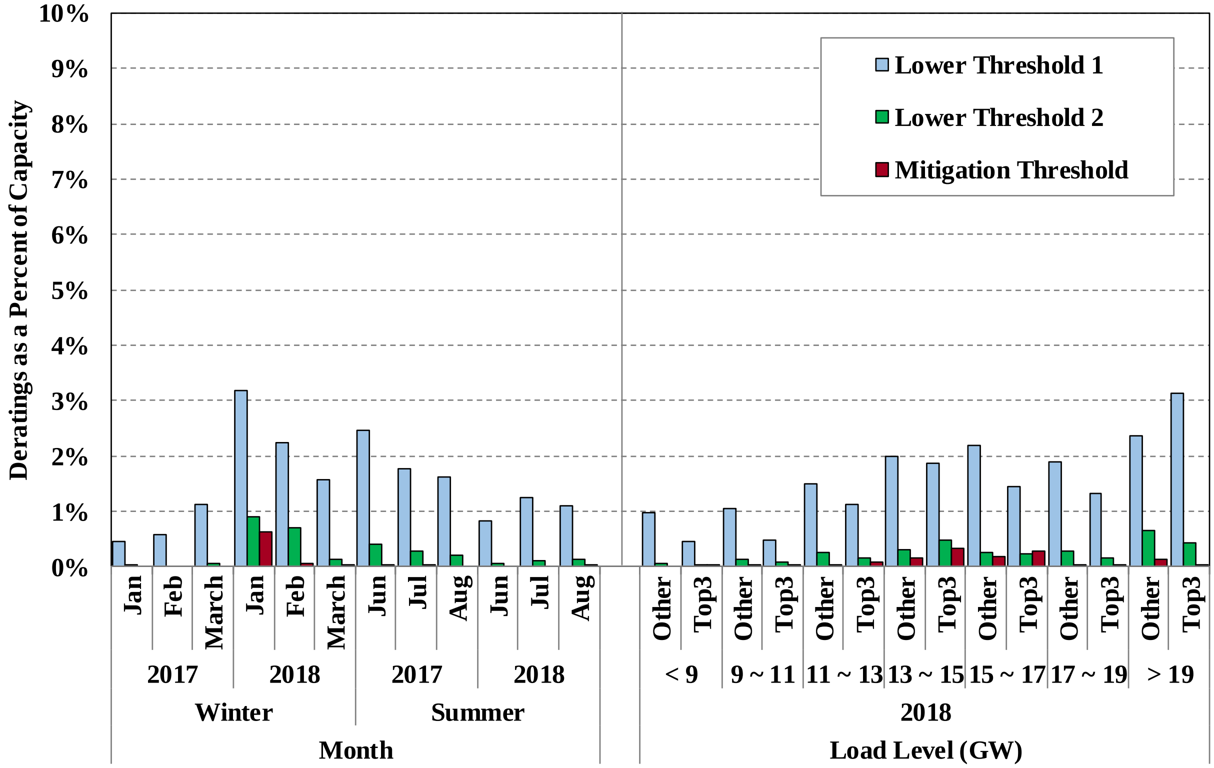
19 Both evaluations exclude capacity from hydro, solar, wind, landfill-gas, and biomass generators. They also exclude nuclear units during maintenance outages, since such outages cannot be scheduled during a period when the generator would not be economic. Sections II.A and II.B in the Appendix show detailed analyses of potential physical and economic withholding.

20 The primary reason for a higher unoffered economic capacity in summer 2018 were forced derates and outages of a nuclear unit, and maintenance outages of several combined cycle units in September.

The amount of output gap in Eastern New York remained very low in 2018, averaging less than 0.1 percent of total capacity at the statewide mitigation threshold and 1.3 percent at the lowest threshold evaluated (i.e., 25 percent above the reference level).

Figure 5: Output Gap in Eastern New York
2017 – 2018



In 2018, the output gap in Eastern New York was largest during the coldest winter months, while in previous years the output gap increased with load and was higher during the summer months. The large Output Gap in January does not raise significant concerns, as it appears to be driven by differences between the fuel costs faced by generators and the fuel index prices. Much of these differences are due to: (a) volatility in gas markets that can lead to large discrepancies between actual fuel costs and published price indices; and/or (b) generators with gas supply limitations that are dependent on the consumption of nearby units whose costs are difficult to reflect dynamically in 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 generally consistent with expectations in a competitive market and did not raise significant concerns regarding potential physical or economic withholding under most conditions.

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 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.[21]
- 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 6 summarizes the market power mitigation (i.e., offer capping) that was imposed in the day-ahead and the real-time markets in 2017 and in 2018.

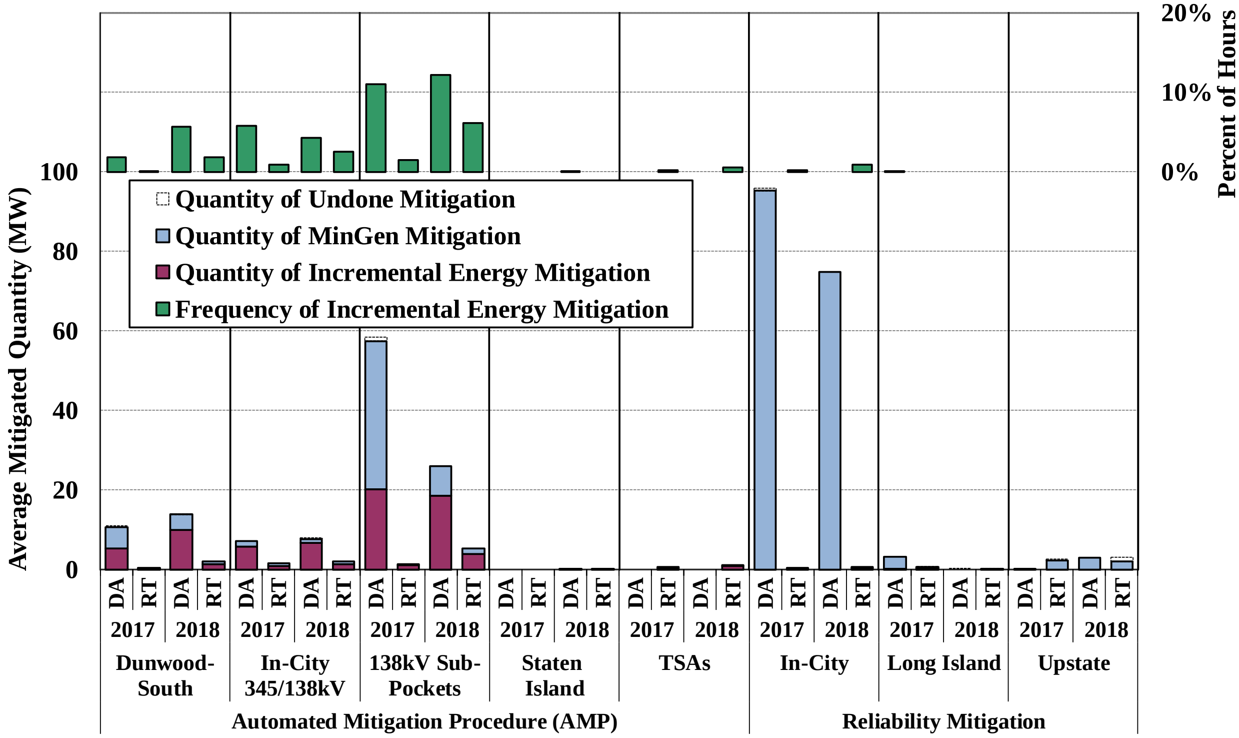
Most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for 58 percent of all mitigation in 2018, nearly all of which occurred in the day-ahead market. Although the amount of capacity committed for reliability in New York City increased from 2017 to 2018, the amount of mitigation of such units decreased. This is largely because the generators that were committed for reliability in 2017 had higher minimum generation levels as a share of their total capability than ones committed for reliability in 2018.[22] Unlike AMP mitigation, these mitigations generally affect guarantee payment uplift, but not energy prices. The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have market power.

21 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.

22 See Section IX.H for more details on higher reliability commitments in New York City.

AMP mitigation accounted for 42 percent of day-ahead mitigation and was down from 2017 in all areas of New York City. This decreased primarily because several generators in the 138 kV sub-pockets of New York City began to submit offers that were more consistent with their reference levels.

Figure 6: Summary of Day-Ahead and Real-Time Mitigation
2017 - 2018



As natural gas markets have become more volatile in recent years, generators have increasingly utilized the Fuel Cost Adjustment ("FCA") functionality to adjust their reference levels in the day-ahead and real-time markets. For instance, on gas days during the cold spell from December 27 to January 8, an average of 1.9 GW (or 18 percent) of NYC generating capacity submitted FCAs for natural gas before the day-ahead market.[23]

The FCA functionality is important because it allows a generator to reflect fuel cost variations closer to when the market clears, and 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 and scheduled. Accordingly, we monitor for biased FCAs and the NYISO administers mitigation measures that impose financial sanctions on generators that submit biased FCAs under certain

23 See Appendix subsection II.C.

conditions. In our review of the winter of 2017/18, we found that some FCAs did not appear to be reasonable. However, the price impact was small because imports, oil-fired generation, and self-scheduled generation were generally sufficient to satisfy demand.

Nonetheless, we have identified circumstances when a supplier could withhold capacity from the market and use a biased FCA to avoid being mitigated and where the mitigation measures are inadequate to deter such conduct. This is because a generator that submits biased FCAs is temporarily barred from using the FCA functionality, but no financial sanction is imposed even if the generator's biased FCAs led to a significant effect on LBMPs. Therefore, we recommend the NYISO modify its tariff so that the market power mitigation measures deter a generator from exercising market power by submitting biased FCAs.[24]

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. Buyer-side 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.[25] Supply-side mitigation measures prevent a supplier with market power from inflating prices above competitive levels by withholding economic capacity in these areas.[26] Given the sensitivity of prices in these areas to both actions, we believe that these market power mitigation measures are essential for ensuring that capacity prices in the mitigated capacity zones are competitive. This section discusses the use and design of capacity market mitigation measures in 2018.

Application of the Supply-Side Mitigation Measures

In April 2018, Helix Ravenswood moved seven GTs located in Zone J into an IIFO. 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.

24 See Section XI, Recommendation #2017-4.

25 The buyer-side mitigation measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. See NYISO MST, Section 23.4.5.7.

26 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. See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests ("METs") and provided BSM determinations for four Examined Facilities in July 2018. These projects were part of the first settlement phase of the bifurcated Class Year 2017 ("CY17-1").[27] The NYISO is evaluating three other Examined Facilities that are part of the second phase of CY17 for Part A/ B tests. Table 4 describes each CY17 Examined Facility and the status of its BSM evaluation.

Table 4: Status of CY17 BSM Evaluations

Examined Facility	Zone	Summer ICAP MW	Type	CY17 Phase	Exempt?
Cricket Valley Energy Center Project ("CVEC Project")	G	1020	CC	17-1	Yes - CEE
Bayonne Energy Center II Project ("BEC II Project")	J	120	CT	17-1	Yes - CEE
Berrians East Replacement Project ("CY17 Berrians Project")	J	508 (Net +4MW)	CT	17-1	Yes - Part B
East River 6 Additional CRIS MW Project ("East River 6 Project")	J	8	Additional CRIS	17-1	Yes - Part B
Champlain Hudson Interconnection Project ("CHPE Project")	J	1000	HVDC Line	17-2	TBD - Part A/B
Linden Cogen Uprate Project ("Linden Uprate Project")	J	234	CT	17-2	TBD - Part A/B
Linden Additional CRIS MW Project	J	37	Additional CRIS	17-2	TBD - Part A/B

Improvements to the Part A and Part B BSM Evaluations

The NYISO made several modifications to its test methodology in the CY17 evaluations.[28] The application of new inclusion and exclusion rules for determining the in-service capacity corrected a major deficiency of the test procedure. In addition, the NYISO forecasted the LCRs using the new LCR methodology after accounting for changes in the resource mix (e.g., Indian Point retirement) and interface transfer limits. Both of these changes had a considerable impact on the CY17-1 price forecasts and significantly enhanced the test procedure.

27 Starting in Class Year 2017, the NYISO issues final determinations in two settlement phases if the Class Year "bifurcates." The first phase is for Examined Facilities that do not require additional System Deliverability Upgrades ("SDU") studies and elect to settle early as part of the first phase of CY. The second phase is for Examined Facilities that require additional SDU studies and elect to proceed with the studies, and for Examined Facilities that do not require additional SDU studied but elect to settle in the second phase. CY17 bifurcated because two Examined Facilities elected to proceed with additional SDU studies.

28 See the MMU's BSM Report for CY17-1 Projects for changes the NYISO made to the test methodology.

Our CY17-1 and past BSM reports have identified additional concerns with several assumptions that are used in the BSM evaluations. Table 5 provides a list of identified issues and whether we have recommended addressing the issue with a process improvement (indicated by an "I") or with a tariff change (indicated by a "T"). The first five improvements in the table are issues that we have recommended in previous state of the market reports,[29] while the last issue constitutes a new recommendation in this report that is discussed further below.

Table 5: Recommended Enhancements to the Part A and Part B BSM Evaluations

Issue	Rec
Interconnection costs may be inflated for some Examined Facilities (Part B test)	T
Starting Capability Period is unrealistic for most Examined Facilities (Part A & B tests)	T
Treatment of some Existing Units at risk of retiring or mothballing is unrealistic for some units (Part A & B tests)	T
Treatment of Examined Facilities seeking Competitive Entry Exemption may be inconsistent with developers' expectations (Part A & B tests)	T
Treatment of exempt Prior Class Year Projects in the Interconnection Queue may be unrealistic (Part A & B tests)	I
Modify Part A test procedure to exempt Zone J projects if they are needed to satisfy the G-J Locality's capacity requirement (Part A test)	T

The last enhancement listed in the table would modify the Part A test, which is designed to exempt a project whose capacity is needed to satisfy the local capacity planning requirement where the project would locate. More specifically, the Part A test exempts a project if the amount of capacity after entry would not exceed the local requirement by more than approximately 6 percent. Thus, a New York City generator would be exempt if it was needed to satisfy the LCR for New York City, but a New York City generator would *not* be exempt if it was needed to satisfy the LCR for the G-J Locality.

Given the large resource mix changes that are expected in the coming years, we recommend modifying the Part A test to test a New York City generator against the larger G-J Locality requirement in addition to the New York City requirement.[30]

29 See Recommendation #2013-2d in Section XI of this report. For details, see the BSM Report for CY17-1.

30 See Recommendation #2018-3 in Section XI of this report. For additional discussion, see the BSM Report for CY17-1.

Application of the BSM Evaluation Process Outside the Class Year Process

In its recent compliance filing in response to Order 841: *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, the NYISO highlighted issues with applying the BSM measures to generators that do not go through the Class Year process because they are smaller than 2 MW.[31] The BSM measures are currently applied within the Class Year process, which was designed for conventional generators that take years to develop and bring into commercial operation. However, battery storage projects and other short lead-time projects are capable of entering in just a few months, so we recommend the NYISO develop a set of procedures and requisite tariff changes for applying the BSM measures outside the Class Year process, perhaps on a quarterly cycle.[32]

Improvements to the Competitive Entry Exemption

The Tariff provides for the NYISO to exempt from BSM the new entrants that meet certain criteria under the Competitive Entry Exemption ("CEE") provisions.[33] The CEE was designed to exempt projects that do not receive support from state government or state-regulated entities. Under the current rules, the Examined Facility's developers are prohibited from direct or indirect contractual relationships with Non-Qualifying Entry Sponsors, although the tariff specifies a list of exceptions to this rule.[34] For example, developers are generally prohibited from contracting with transmission-owning utilities, but exceptions are made for interconnection agreements.

However, it is typical for suppliers to enter into offtake arrangements (e.g. PPAs for hedging the project risk) with a range of counterparties (including non-qualifying entities) to support development of new projects. Such contracts can be competitive (i.e., not constitute an attempt to suppress capacity prices). Accordingly, we recommend the NYISO modify its rules and expand the list of eligible contracts to include power supply agreements that can be determined to competitive and non-discriminatory.[35] For example, if a regulated utility runs an auction to buy power that is competitive and open to all suppliers, the NYISO could determine that the resulting contract will not serve as a conduit for subsidies to the seller. This change would allow

31 See comments of the Market Monitoring Unit filed on February 25, 2019 in Docket ER19-467-000.

32 See Recommendation #2018-4 in Section XI of this report.

33 MST Section 23.4.5.7.9.

34 Non-Qualifying Entry Sponsors are defined in the tariff as a Public Power Entity, a Transmission Owner with a Transmission District in the NYCA, any other entity with a Transmission District in the NYCA, or any agency or instrumentality of New York State or a political subdivision thereof. See MST Section 23.4.5.7.9.1.1

35 See Recommendation #2018-2 in Section XI of this report.

generators and utilities to enter into competitive contracts to hedge risk while still fulfilling the objectives of the buyer-side mitigation measures.

Potential Expansion of Buyer-Side Mitigation Measures

In response to a complaint by the Independent Power Producers of New York, the Commission recognized that the current BSM measures do not address all potential conduct that may suppress capacity prices.[36] To determine whether the BSM measures should be expanded to address additional types of conduct and capacity zones, the NYISO evaluated the incentives to suppress capacity prices. The NYISO concluded that there are incentives to retain existing capacity resources after their continued operation is uneconomic, and we agree.[37] Uneconomic retention, like uneconomic entry, can undermine long-term performance of the market by distorting short-term prices and creating increased economic risks for suppliers. Hence, we recommended an offer floor be applied to a generator (at its going-forward cost level) if an above-market contract causes an uneconomic generator to remain in operation. In contrast, the NYISO proposed a process for simply monitoring such activity in a compliance filing. The Commission has not issued a ruling.[38]

We also recognize that states have public policy goals that may entail support for certain types of resources, and we recognize that the current markets do not fully price many externalities of electricity generation, including environmental emissions. Thus, state subsidies that can be justified by the cost/value of the externalities could be reasonable.

Recognizing the need to harmonize state policies with its markets, the NYISO is working with its stakeholders to integrate the cost of carbon into wholesale electricity markets in a technology-neutral, non-discriminatory manner.[39] The costs of reducing CO_2 emissions varies by technology and location.[40] We support the NYISO's approach because it would compensate participants in a transparent and non-discriminatory manner, which should motivate efficient decisions that minimize the costs of satisfying the carbon reduction objective.[41]

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36 See the Commission's Order on March 19, 2015: *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, 150 FERC ¶ 61,139.

37 See NYISO filing dated December 16, 2015: *Response to Information Request*, Attachment II – pages 13 to 20, Docket No. EL13-62-002.

38 See MMU's comments filed on January 11, 2016 in Docket No. EL13-62.

39 See presentation by Michael DeSocio on December 17, 2018 at IPPTF meeting on *IPPTF Carbon Pricing Proposal*.

40 See Section VIII.B of the 2016 State of the Market Report.

41 See May 9, 2019 presentation to ICAPWG on *MMU Evaluation of Impact of Carbon Pricing* for the impacts of the NYISO's carbon pricing proposal on consumer costs and overall emissions.

Although carbon pricing would not automatically exempt all resources that are subsidized for public policy reasons, it would greatly reduce the amount of capacity that would not be exempt under the Part B test. Furthermore, carbon pricing would provide market signals that would encourage the retirement of some older existing generators. Such retirements would, in turn, make new subsidized resources more likely to be exempt under the Part A and Part B tests. In conjunction with a renewable exemption, carbon pricing would likely lead much of capacity that currently receives subsidies to be exempt from mitigation. [42]

[42] Although the Commission has not accepted the NYISO's compliance filing proposing a BSM exemption for renewable generation, the Commission ordered the NYISO to develop one. See December 3, 2018 *New York Independent System Operator, Inc: Compliance Filing and Request for Extension of Time of Effective Date*, and February 25, 2019 MMU comments on NYISO compliance filing, Docket No. ER19-467-000.

IV. DAY-AHEAD MARKET PERFORMANCE

The day-ahead market enables firms to make forward purchases and sales of power for delivery in real-time the following 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 the day-ahead and real-time energy and ancillary services prices and analyze virtual trading and other day-ahead scheduling patterns.

A. Day-Ahead to Real-Time Price Convergence

Convergence of Zonal Energy Prices

The following table 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, as well as the average absolute value of the difference between hourly day-ahead and real-time prices.[43] These statistics are shown on an annual basis.

Table 6: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2017-2018

	Annual Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff	
Zone	2017	2018	2017	2018
West	-1.0%	0.7%	44.4%	40.6%
Central	-0.6%	-1.9%	35.8%	35.1%
North	5.5%	-3.3%	58.1%	55.6%
Capital	1.2%	-1.3%	31.7%	31.8%
Hudson Valley	1.7%	-1.1%	30.6%	31.2%
New York City	2.3%	-3.2%	31.6%	31.5%
Long Island	3.2%	1.6%	39.1%	37.7%

Overall, day-ahead prices were lower on average than real-time prices by a small margin in most areas in 2018. In general, a small day-ahead premium is expected in a competitive market, since load serving entities and other market participants avoid buying at volatile real-time prices by shifting more of their purchases into the day-ahead market. However, small real-time premiums occurred in 2018 primarily because of large real-time price spikes during the severe cold weather

43 Section I.G in the Appendix shows monthly variations of average day-ahead and real-time energy prices.

in January 2018. Removing the effects of the January cold spell would result in (a) small day-ahead premiums in several regions, and (b) much smaller differences between average day-ahead and real-time prices in 2018 relative to 2017.[44]

The average absolute difference between day-ahead and real-time prices fell in the West Zone, the North Zone, and Long Island from 2017 to 2018. The improved convergence resulted from lower real-time price volatility in certain areas that are affected by transmission constraint violations. Modifications to the GTDC in June 2017 resulted in lower and more predictable congestion for most transmission corridors during transmission shortages.[45]

Notwithstanding these improvements, the average absolute difference continues to indicate the highest volatility is in Western and Northern New York. These areas have: (a) substantial amounts of intermittent renewable generation, (b) interfaces with Ontario and Quebec that convey large amounts of low-cost imports that are relatively 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 western and northern New York.

Convergence of Nodal Energy Prices

Certain generator nodes exhibited less consistency between average day-ahead and real-time prices than zonal prices did in 2018.[46] In this subsection, we discuss two such nodes where convergence was particularly poor in 2018. First, on the east end of Long Island, management of constraints on 138 kV and 69 kV circuits flowing power towards the east end of Long Island led to significant differences between day-ahead and real-time congestion pricing patterns. This resulted in a large day-ahead premium ($20/MWh during the summer). Second, real-time prices in the Valley Stream pocket on the west end of Long Island exhibited significant premiums over day-ahead prices in 2018. This was driven by acute 5-minute ramp limitations and poor consistency between RTC and RTD.

Nodal congestion may sometimes fail to converge between the day-ahead and the real-time markets even though convergence is good at the zone level. Allowing virtual trading at a nodal level would enable market participants to better arbitrage day-ahead and real-time congestion. This would help improve consistency between day-ahead and real-time prices and ensure adequate resources are committed in the day-ahead market in sub-zonal areas.

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44 See Section I.G in the Appendix for other instances of unexpected events that contributed to real-time premia in several areas in 2018.

45 See Section V.G in the Appendix for a more detailed analysis on the impact of GTDC changes on prices.

46 See Section I.G of the Appendix for detailed results.

Convergence of Ancillary Service Prices

Day-ahead prices for operating reserves continued to be systematically higher than real-time prices in 2018. This premium for operating reserves in the day-ahead market arises because the day-ahead market schedules operating reserves based on the availability offers of generators and the opportunity costs of not providing other products, while the real-time market schedules reserves based on opportunity costs only (since a generator offering energy in the real-time market does not incur an additional cost to be available to provide reserves).[47]

The NYISO plans to file to create operating reserve requirements in Zone J. These will include a 500 MW 10-minute reserve requirement and a 1,000 MW 30-minute reserve requirement, both of which would have $25/MWh operating reserve demand curves.[48] The low operating reserve demand curves for these requirements as well as the existing market power mitigation measures will limit the potential price increases that could result from these changes, however, we will continue to monitor day-ahead reserve offer patterns and consider whether mitigation rule changes are needed to ensure competitive market outcomes.

Convergence of day-ahead and real-time prices for all reserve products worsened in 2018 when compared to 2017. This is largely because of tight system conditions on a small number of days in 2018 (due to severe cold weather, supply contingencies, and thunderstorm alerts) led to real-time price spikes and were not reflected in day-ahead prices.

B. Day-Ahead Load Scheduling and Virtual Trading

Convergence between day-ahead and real-time energy prices is generally better at the zone level than at the node level partly because physical loads and virtual traders are able to bid at the zonal level in the day-ahead market. Under-scheduling load generally leads to lower day-ahead prices, while over-scheduling can raise day-ahead prices above real-time prices. 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.

Table 7 shows the average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2017 and 2018 for several regions.[49] Overall, net scheduled load in the day-ahead market was roughly 96 percent of actual NYCA

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47 The availability offers of generators in the day-ahead market consider several factors. See Appendix section I.H for a discussion of factors that could influence day-ahead reserve offers.

48 See "Establishing Zone J Operating Reserves" by Ashley Ferrer at MC meeting on March 27, 2019.

49 Figure A-38 to Figure A-45 in the Appendix also show these quantities on a monthly basis.

load during daily peak load hours in 2018, similar to 2017 (95 percent). However, day-ahead net load scheduling patterns in some of the sub-regions exhibited some changes from 2017 to 2018.

Table 7: Day-Ahead Load Scheduling versus Actual Load
By Region, During Daily Peak Load Hours, 2017 – 2018

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2017	97.3%	0.0%	-4.6%	22.4%			115.1%
	2018	95.4%	0.0%	-2.6%	17.4%			110.2%
Central NY	2017	120.4%	0.0%	33.8%	3.1%			89.8%
	2018	114.9%	0.0%	31.3%	4.0%			87.7%
North	2017	99.9%	0.0%	-58.4%	4.4%			45.9%
	2018	94.7%	0.0%	-46.3%	4.6%			53.0%
Capital	2017	97.8%	0.0%	-17.3%	4.5%			84.9%
	2018	95.9%	0.0%	-6.5%	4.5%			93.8%
Lower Hudson	2017	79.8%	20.1%	-19.3%	8.1%			88.7%
	2018	73.6%	23.2%	-14.8%	13.2%			95.2%
New York City	2017	78.8%	18.4%	-1.0%	4.9%			101.2%
	2018	70.1%	26.0%	-1.2%	5.9%			100.8%
Long Island	2017	100.2%	0.0%	-2.0%	7.6%			105.8%
	2018	101.0%	0.0%	-3.3%	7.7%			105.5%
NYCA	2017	94.1%	8.7%	-13.0%	6.9%	-3.0%	1.3%	95.0%
	2018	89.1%	11.5%	-11.0%	7.6%	-2.4%	1.1%	95.9%

Table 6 shows that average net load scheduling tends to be higher where volatile real-time congestion often leads to very high (rather than low) real-time prices. Net load scheduling was generally higher in New York City and Long Island because they were downstream of most congested interfaces. Net load scheduling was highest in the West Zone because of volatile real-time congestion on the 230kV system there. Over-scheduling generally helped improve the commitment of resources in these areas. Nonetheless, over-scheduling in the West Zone has fallen since 2016 because of less volatile real-time congestion due to market enhancements and transmission upgrades. The NYISO incorporated most 115 kV West Zone constraints in the market software in December 2018, which has further reduced differences between day-ahead and real-time markets in this region.

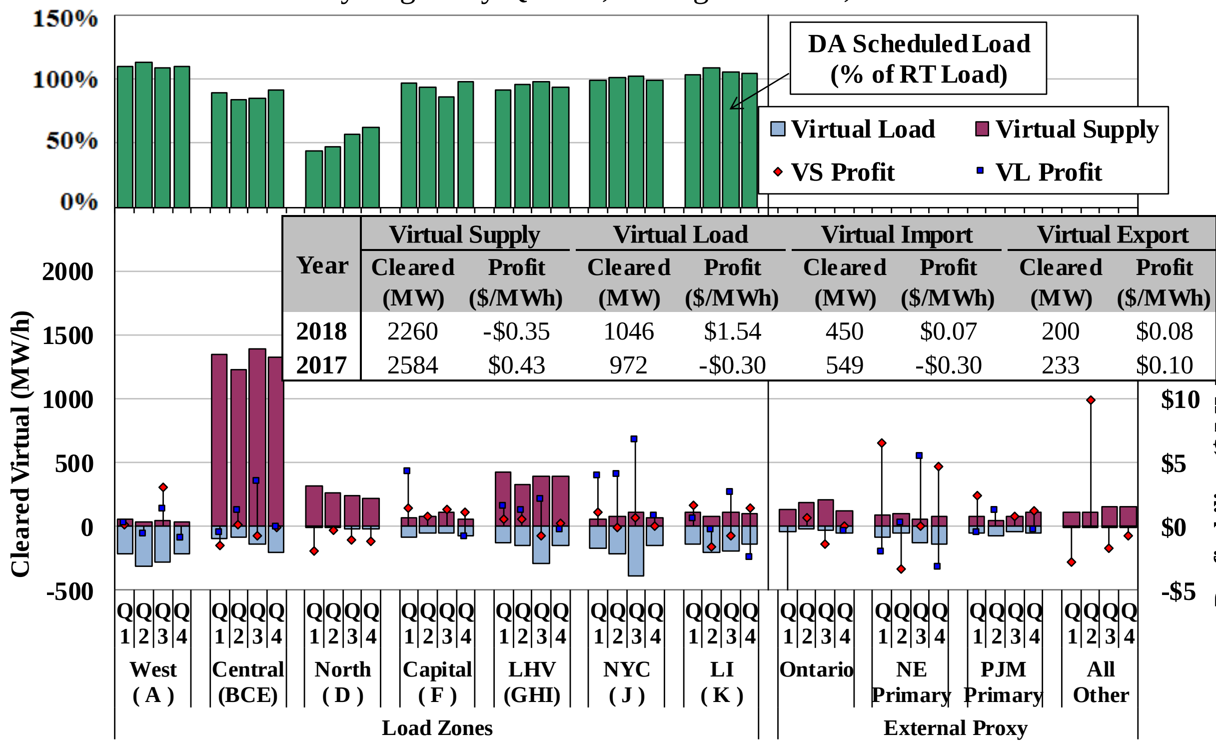
Net load scheduling was generally lower in other regions. Load was under-scheduled most in the North Zone where real-time prices can fall to very low (negative) levels when transmission bottlenecks limit the amount of renewable generation and imports from Ontario and Quebec that can be delivered south towards central New York. However, the net load scheduling increased modestly from 2017 to 2018.

Net load scheduling rose in the Lower Hudson Valley region because more virtual load was scheduled in the summer months as market participants anticipated increased congestion in this region because of higher load levels and more frequent peaking conditions.

As discussed above, net day-ahead scheduling patterns are determined by virtual trading activity to a large extent. Figure 7 summarizes virtual trading by location in 2018, including internal zones and external interfaces.[50] The pattern of virtual trading did not change significantly in 2018 from the prior year, with the exception of Capital Zone which saw a noticeable reduction in virtual supply. Virtual traders generally scheduled more virtual load in the West Zone, New York City and Long Island and more virtual supply in other regions. This pattern was consistent with the day-ahead load scheduling patterns discussed earlier and occurred for similar reasons.

Figure 7: Virtual Trading Activity

by Region by Quarter, During All Hours, 2018



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)
2018	2260	-$0.35	1046	$1.54	450	$0.07	200	$0.08
2017	2584	$0.43	972	-$0.30	549	-$0.30	233	$0.10

The profits and losses of virtual load and supply have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices. Nonetheless, virtual traders netted a gross profit of approximately $7.5 million in 2018, indicating that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability was $0.22 per MWh in 2018, higher than the $0.16 per MWh in 2017. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market.

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50 See Figure A-47 in the Appendix for a detailed description of the chart.

V. 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.

This section discusses three aspects of congestion management in 2018:

- Day-ahead and real-time transmission congestion
- Transmission constraints on the low voltage network
- Transmission congestion contracts

In addition, general congestion patterns are summarized in Section II.E, while the Market Operations section also evaluates elements of congestion management.[51]

A. Day-ahead and Real-time Transmission Congestion

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.[52] 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 two locations. However, no TCCs that are sold for real-time congestion since most power is scheduled through the day-ahead market.

This subsection analyzes congestion that is managed by scheduling resources in the day-ahead and real-time markets to provide relief. This subsection also evaluates transmission constraints on the low voltage network in upstate New York that are managed through out-of-market actions by the operators (since they are not managed as other constraints through the day-ahead and real-time markets). Out-of-market actions have become increasingly common in recent years due to the retirement of generation on the low-voltage network.

Figure 8 evaluates overall congestion by summarizing:

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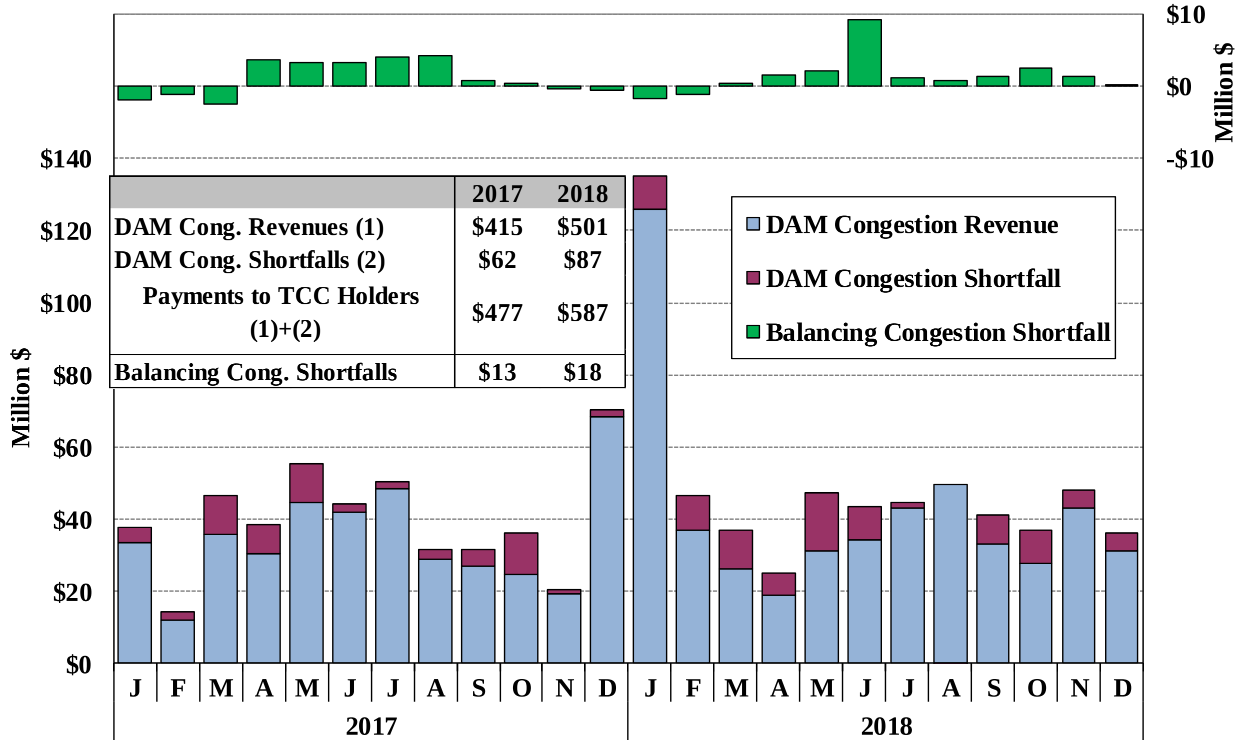
51 The Market Operations section evaluates pricing during transmission shortage conditions (IX.B), the use of reserve units to manage New York City transmission congestion (IX.D), and the coordinated congestion management with PJM (IX.F).

52 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., congestion component at the sink minus congestion component at the source). Congestion charges to other purchases and sales are based on the congestion component of the LBMP at the purchasing or selling location.

- 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 – This uplift occurs when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders. This is caused when the amount of TCC sold by the NYISO exceeds the transmission capability of the power system as modeled in the day-ahead market.
- Balancing Congestion Shortfalls – This uplift arises when day-ahead scheduled flows over a constraint exceed what can be scheduled to flow in the real-time market.

Figure 8: Congestion Revenues and Shortfalls
2017 – 2018



	2017	2018
DAM Cong. Revenues (1)	$415	$501
DAM Cong. Shortfalls (2)	$62	$87
Payments to TCC Holders (1)+(2)	$477	$587
Balancing Cong. Shortfalls	$13	$18

Congestion revenues and shortfalls increased from 2017 to 2018. In particular:

- Day-ahead congestion revenues rose 21 percent to $501 million;
- Day-ahead congestion shortfalls rose 40 percent to $81 million; and
- Balancing congestion shortfalls rose 38 percent to $18 million.

Day-Ahead Congestion Revenues

Day-ahead congestion revenues rose from 2017 and 2018, consistent with:

- Higher load levels and more frequent peaking conditions, which increased flows across the network and led to more transmission bottlenecks; and

- Higher natural gas prices, which increased the redispatch cost of relieving congestion.

These had the most significant effects in January, resulting in a total of $126 million (accounting for 25 percent of the annual total) of day-ahead congestion revenues. Roughly $56 million of these congestion revenues accrued in the first eight days of January when a Cold Spell (aka, the "Bomb Cyclone") led to substantially elevated load levels and natural gas prices.

Transmission outages played a key role in driving congestion patterns, especially from North to Central New York, from upstate into the 345 kV system of New York City, and across the primary interface between NYISO and ISO-NE. On the other hand, the Central-East interface and from Capital to Hudson Valley had less congestion because of fewer costly outages.

Changes in congestion patterns from 2017 to 2018 were also affected by the following factors:

- Expiration of the ConEd/PSEG Wheeling Agreement in May 2017 – This reduced imports (by several hundred MW) from PJM to New York City across the A, B, and C lines and increased congestion in New York City;
- Modification of transmission shortage pricing in June 2017 – This led to lower and less volatile congestion shadow prices on most constraints during transmission shortages;
- Inclusion of West Zone constraints in the M2M process with PJM in May 2017 – This helped reduce congestion in the West Zone;
- Modeling 115 kV transmission constraints – The NYISO began modeling 115 kV circuits from North to Central New York in May 2018 and in Western New York in December 2018, which reduced priced congestion across the higher voltage networks in both areas;
- Reduced CRM values for small transmission facilities in December 2018 – The CRM values for 115 kV facilities were unnecessarily high to conform with approved tariff rules the constraints were first modeled, contributing to higher congestion over these constraints. The NYISO filed tariff revisions with the FERC to allow the use of lower CRM values for small facilities, effective in December; and
- Improved modeling of the Niagara Plant in December 2018 – This better recognizes the different congestion impact from 115 kV and 230 kV units, enabling the NYISO to send signals to the Plant that allow more of its output to be deliverable through the West Zone.

Day-Ahead Congestion Shortfalls

Day-ahead shortfalls occur when the day-ahead network capability is less than the capability reflected in TCCs, while day-ahead surpluses (i.e., negative shortfalls) occur when day-ahead schedules across a binding constraint exceed the amount of TCCs. Table 8 shows total day-ahead congestion shortfalls for selected transmission facility groups.[53] Day-ahead congestion

53 Section III.E in the Appendix also provides detailed description of each transmission facility group and summarizes the day-ahead congestion shortfalls on major transmission facilities.

shortfalls increased 40 percent from $62 million in 2017 to $87 million in 2018, primarily because of more costly transmission outages.

Table 8: Day-Ahead Congestion Shortfalls in 2018

Facility Group	Annual Shortfalls ($ Million)
North to Central	$27.4
NYC Lines	$21.7
Primary NY/NE Interface	$17.3
West Zone Lines	$15.5
Central to East	$9.1
All Other Facilities	-$4.7

North to Central – These lines accrued more than $27 million of shortfalls in 2018, noticeably higher than in 2017 primarily because of transmission outages on the Marcy 345 kV lines, the Moses-Adirondack 230 kV lines, and Brownfalls-Taylorville 115 kV lines in several periods of 2018. Most of these outages occurred in the shoulder months.

New York City – Nearly $22 million of shortfalls accrued on New York City lines in 2018, up 133 percent from 2017. Nearly 60 percent of these shortfalls accrued because of the lengthy outages of one of the Dunwoodie-Motthaven 345 kV lines (for more than 4 months) and the B and C PAR-controlled lines (for almost a year). The majority of the remaining shortfalls accrued on transmission lines into the Greenwood load pocket, primarily in January and February when one of the Gowanus-Greenwood lines was OOS.

Primary NY/NE Interface – The interface accounted for more than $17 million of shortfalls in 2018. The interface limit was greatly reduced (from 1,400 MW to around 500 MW) during lengthy transmission outages of: a) the New Scotland-Alps 345 kV line (for about one month); and b) the Long Mountain-Pleasant Valley 345 kV line (for a total of about three months).

West Zone – West Zone lines saw an increase in shortfalls as well partly because of the costly transmission outages of Niagara-Robinson Rd 230 kV line on several days and partly because of increased loop flows in the clockwise direction around Lake Erie.

Central-East interface. The interface accounted for noticeably less shortfalls primarily because of fewer costly planned transmission outages.

The NYISO allocates day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[54] In 2018, the NYISO allocated 82 percent of the net total day-ahead congestion shortfalls in this manner, up slightly from 2017. Transmission owners can schedule outages in ways that reduce labor and other maintenance costs, but these savings should

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

be balanced against the additional uplift costs from congestion shortfalls. Allocating congestion shortfalls to the responsible transmission owners is a best practice for RTOs because it provides incentives to minimize the overall costs of transmission outages.[55]

Congestion shortfalls that are not allocated to individual transmission owners are currently allocated to statewide. These shortfalls typically result from modeling inconsistencies between the TCC auction and day-ahead market that do not result from the outage of a NYCA facility. This includes factors such as the assumed level of loop flows (which is significant for West Zone lines) and statuses of generators, capacitors, and SVCs (which affect the Central-East interface).

Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in the 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 through Rate Schedule 1 charges.[56] Table 9 shows total balancing congestion shortfalls by transmission facility group.[57]

Balancing congestion shortfalls were generally small on most days of 2018 but rose notably on several days when unexpected real-time events occurred. TSA events were a key driver of high balancing shortfalls on these days, during which the transfer capability into Southeast New York was greatly reduced in real time, accounting for $8 million of shortfalls in 2018. Unplanned or forced outages were another key driver. For example, more than $6 million of shortfalls accrued on the corridor from the North Zone to the Central Zone during a five-day period in June when the UCC2-41 Line (i.e., the Marcy-Frasannx-Coopers Corners line) was forced out.

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55 Transmission outages can also result in uplift from balancing congestion shortfalls and BPCG payments to generators running out-of-merit for reliability, most of which are assigned to the transmission owner.

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

57 Figure A-56 in the Appendix summarizes the balancing congestion shortfalls by facility group for 2017 and 2018 by month. Section III.E in the Appendix also provides detailed description for these transmission facility groups and a variety of reasons why their actual flows deviated from their day-ahead flows.

Table 9: Balancing Congestion Shortfalls in 2018 [58]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, ABC & JK PARs	**$1.2**
Other Factors	**$1.0**
North to Central	**$10.3**
Central to East	
Ramapo, ABC & JK PARs	**-$3.2**
Other Factors	**$2.5**
TSA Constraints	**$7.9**
Long Island Lines	**$2.0**
All Other Facilities	**$0.9**

The PAR operations under the M2M JOA with PJM has provided significant benefits to the NYISO in managing congestion on coordinated transmission flow gates. Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $3.2 million of *surpluses* from relieving Central-East congestion, which were partly offset by $1.2 million of *shortfalls* on West Zone lines. However, it is noted that the net surpluses fell from $5.6 million in 2017 partly because the B and C PAR-controlled lines were out of service for almost the entire year. The Ramapo PAR-controlled line normally accrues the most surpluses because it is operated more actively than the ABC and JK PARs to reduce congestion.[59]

B. Transmission Constraints on the Low Voltage Network in New York

Transmission constraints on 138 kV and above facilities are generally managed through the day-ahead and real-time market systems. 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, transmission constraints on the 115 kV and lower voltage networks in New York were resolved primarily through out-of-market actions until May 2018 when the NYISO started to incorporate certain 115 kV constraints in the market software, including:

- Out of merit dispatch and supplemental commitment of generation;

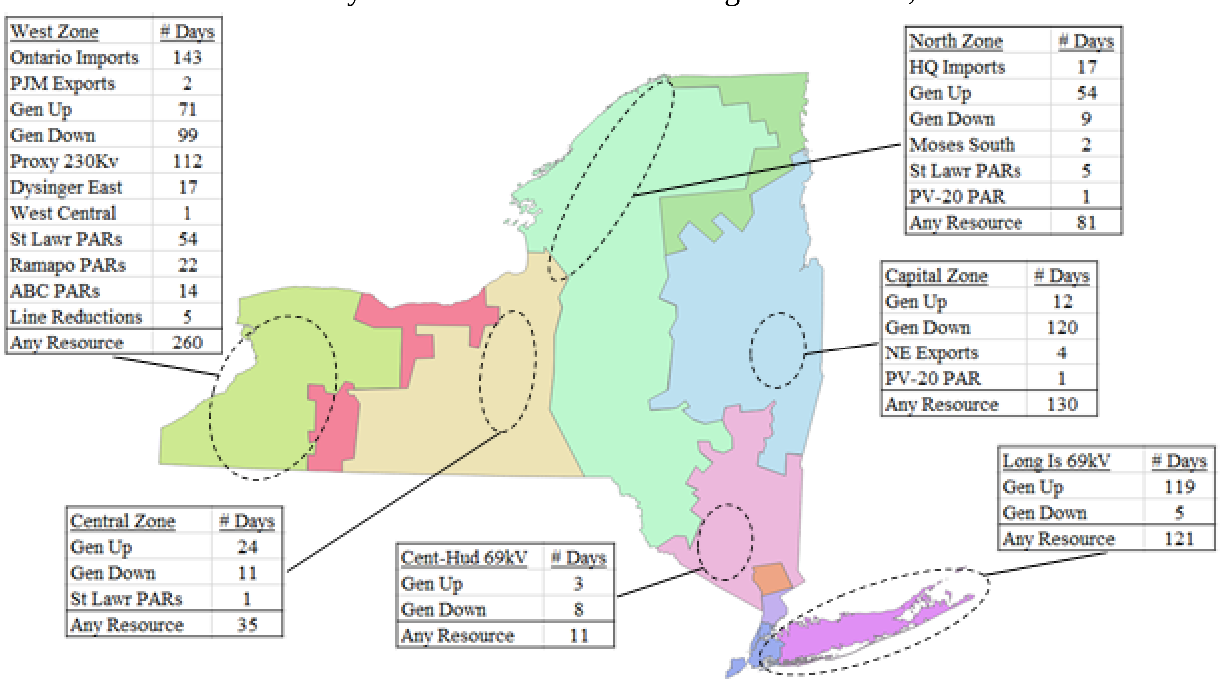
58 The balancing congestion shortfalls estimated in this table differ from actual balancing congestion shortfalls because the estimate: (a) is partly based on real-time schedules rather than metered injections and withdrawals; and (b) uses the original constraint shadow costs from the dispatch model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

59 See Figure A-77 in the Appendix for the PAR operations under M2M with PJM.

- 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.

Figure 9 evaluates the frequency of out of market actions to manage constraints on the low voltage network in six areas of New York: a) West Zone; b) Central Zone; c) Capital Zone; d) North and Mohawk Valley Zones; e) Hudson Valley Zone; and f) Long Island Zone. The tables in the figure summarize the number of days in 2018 when various types of resources were used in each area.

Figure 9: Constraints on the Low Voltage Network in New York
Summary of Resources Used to Manage Constraints, 2018



West Zone	# Days
Ontario Imports	143
PJM Exports	2
Gen Up	71
Gen Down	99
Proxy 230Kv	112
Dysinger East	17
West Central	1
St Lawr PARs	54
Ramapo PARs	22
ABC PARs	14
Line Reductions	5
Any Resource	260

North Zone	# Days
HQ Imports	17
Gen Up	54
Gen Down	9
Moses South	2
St Lawr PARs	5
PV-20 PAR	1
Any Resource	81

Capital Zone	# Days
Gen Up	12
Gen Down	120
NE Exports	4
PV-20 PAR	1
Any Resource	130

Long Is 69kV	# Days
Gen Up	119
Gen Down	5
Any Resource	121

Central Zone	# Days
Gen Up	24
Gen Down	11
St Lawr PARs	1
Any Resource	35

Cent-Hud 69kV	# Days
Gen Up	3
Gen Down	8
Any Resource	11

The West Zone continued to exhibit the most frequent congestion on the low voltage network among the six areas in 2018. Congestion of the 115 kV facilities in the West Zone has become more prevalent even than congestion on the 230 kV network.[60] In 2018, resources were utilized out-of-market to manage 115 kV constraints on 260 days compared to just 167 days of congestion on the 230 kV network in the day-ahead or real-time market. In addition, a 230 kV facility connecting NYISO to PJM (the "Dunkirk-South Ripley" line, which is not shown in the

60 These constraints have been more prevalent since May 2016 when transmission upgrades were made (to reduce congestion on 230 kV facilities in the West Zone following the retirement of the Huntley plant) that shifted some west-to-east flows onto the 115 kV network.

figure) was taken out of service to manage 115 kV constraints on nearly every day of the year.[61] Out-of-market actions became much less frequent in early-December 2018 when the NYISO began to model most 115 kV facilities in the West Zone in the day-ahead and real-time markets.

From the North Zone to central New York, resources were used out of market to manage the 115 kV facilities on 81 days in 2018. However, this was down notably from the 120 days in 2017 largely because the NYISO started to model 115 kV constraints in that area in the day-ahead and real-time markets in May 2018.

In Northern and Western New York, operator actions to manage the 115 kV constraints included:

- Limiting low-cost imports from Ontario and Quebec;
- Limiting generation from the Niagara Plant and other renewable generation;
- Limiting flows using surrogate interface constraints (e.g., Dysinger East interface, West to Central interface, and an increased CRM for Packard-Sawyer 230 kV lines); and
- Using phase-angle regulators in Northern New York (i.e., the Saint Lawrence PARs) and Southeast New York (i.e., the Ramapo and ABC PARs).

The first three manage congestion by reducing low-cost generation and may raise LBMPs in other areas. The last one may exacerbate congestion in other areas and raise overall congestion costs. For example, using PARs in the North Zone to relieve constraints in the West Zone often exacerbates constraints going south from the North Zone and across the Central-East interface.[62] Therefore, it is important to manage congestion on these low-voltage network efficiently.

The day-ahead and real-time market systems are designed to manage congestion optimally, balancing the benefits of relieving constraints against the cost of exacerbating other constraints. Recognizing this, the NYISO implemented three market enhancements in 2018: [63]

- Modeling 115 kV constraints between northern and central New York in May;
- Modeling 115 kV constraints in western New York in December; and
- Improving modeling of the Niagara plant to better recognize the different congestion impact from its 115 kV and 230 kV units.[64, 65]

61 This line was reconnected on just a few days at the request of PJM to facilitate outage work.

62 Similarly, using PARs in Southeast New York to relieve West Zone constraints exacerbates constraints across the Central-East interface and into New York City.

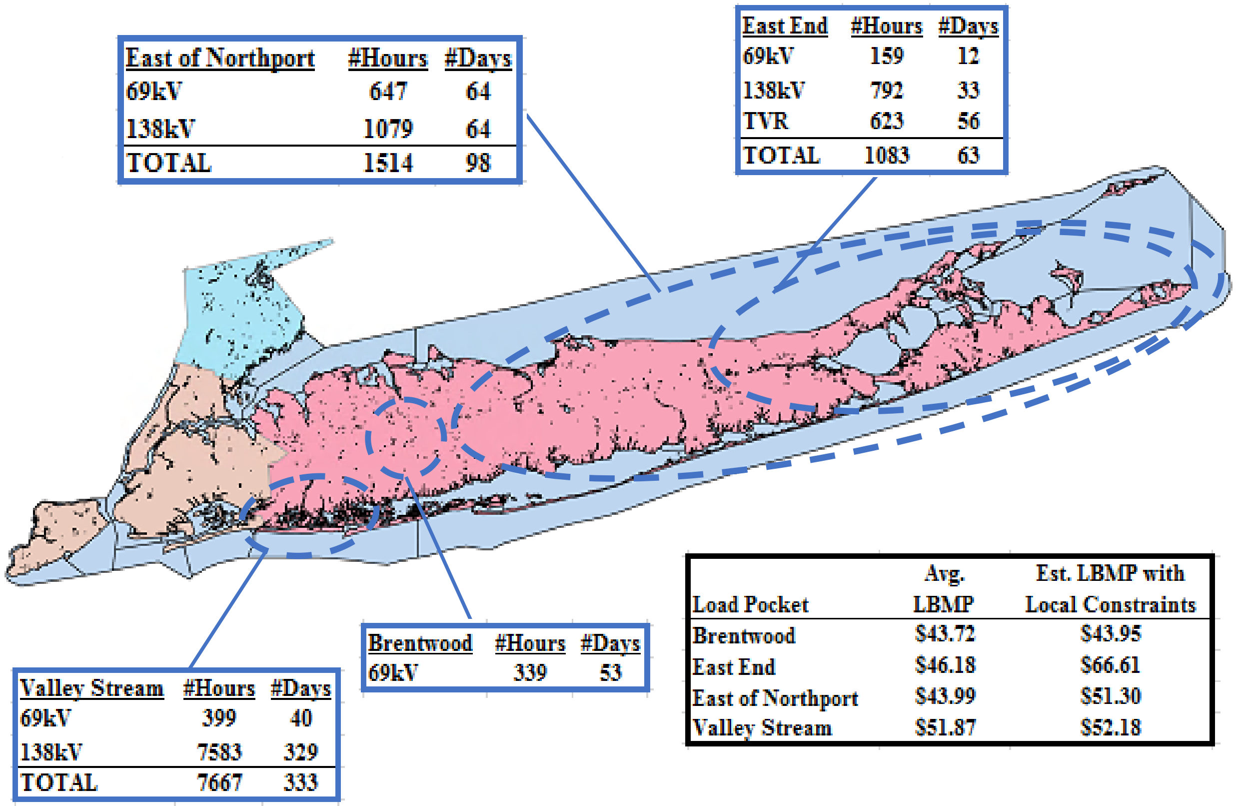
63 The 2017 SOM Report Recommendation #2014-12 proposed modeling these 115kV constraints.

64 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 to consumers.

65 See *Niagara Generation Modeling Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

Figure 10 evaluates the frequency of actions to manage 69 kV constraints on Long Island. Since most load pockets are fed by 69 kV and 138 kV transmission circuits, the figure shows how frequently this congestion is managed through the day-ahead and real-time markets (for 138 kV facilities) and how frequently it is managed through out-of-merit actions (for 69 kV facilities). An inset table shows the average estimated LBMP in each pocket reflecting the marginal costs of resources used to manage 69 kV constraints.

Figure 10: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2018



East of Northport	#Hours	#Days
69kV	647	64
138kV	1079	64
TOTAL	1514	98

East End	#Hours	#Days
69kV	159	12
138kV	792	33
TVR	623	56
TOTAL	1083	63

Brentwood	#Hours	#Days
69kV	339	53

Valley Stream	#Hours	#Days
69kV	399	40
138kV	7583	329
TOTAL	7667	333

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	\$43.72	\$43.95
East End	\$46.18	\$66.61
East of Northport	\$43.99	\$51.30
Valley Stream	\$51.87	\$52.18

OOM dispatch was frequently (on 119 days) used to manage low-voltage constraints on Long Island. These actions reduced LBMPs in Long Island load pockets, resulting in roughly \$10 million of BPCG uplift in 2018. Our estimates show that if these constraints had been modeled in 2018 average LBMPs would have:

- Risen 17 percent in the East of Northport load pocket of Long Island and
- Risen 44 percent in the East End load pocket on Long Island.[66]

Setting LBMPs on Long Island more efficiently to recognize the marginal cost of satisfying local transmission constraints would provide better signals for future investment. This is particularly

66 See Figure A-53 in the Appendix for more details.

important now as investment decisions are being made to determine how best to satisfy reliability needs and environmental policy objectives in Long Island over the coming decades. Hence, we recommend the NYISO consider modeling the 69 kV constraints and East End TVR needs (using surrogate thermal constraints) in the market software.[67]

C. Transmission Congestion Contracts

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 2017/18 and Summer 2018 Capability Periods (i.e., November 2017 to October 2018).

Table 10 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[68]

- 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.

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2017 to October 2018 netted a total profit of $47 million. Overall, the net profitability for TCC holders in this period was 19 percent (as a weighted percentage of the original TCC prices), up from 5 percent in the previous 12-month period.

In this reporting period, TCC buyers netted sizable profits on: a) intra-zonal transmission paths in New York City and Long Island; and b) inter-zonal transmission paths sinking at the New England proxy bus and at the zones in Central New York. Their net profitability ranged from 78 percent to 102 percent. This was in line with changes in the congestion pattern from the prior year. For example, the day-ahead congestion revenues that accrued on transmission facilities in New York City rose 83 percent from 2017 to 2018, and the day-ahead congestion revenues that accrued on the "North to Central" transmission facilities rose 95 percent (for the reasons discussed in Section II.E).

67 See Recommendation #2018-1 in Section XI.

68 Section III.F in the Appendix describes the methodology to break each TCC into inter-zonal and intra-zonal components.

Table 10: TCC Cost and Profit
Winter 2017/18 and Summer 2018 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$13	-$0.2	-2%
New York City	$12	$12	102%
Long Island	$8	$7	98%
All Other	$14	-$3	-21%
Total	**$46**	**$16**	**36%**
Inter-Zonal TCC			
Other to West Zone	$33	$3	10%
Other to Hud VL	$76	-$35	-46%
Other to Central New York	$41	$32	78%
Other to New England	$25	$24	98%
All Other	$33	$6	18%
Total	**$206**	**$30**	**15%**

Conversely, TCC buyers netted a large loss of 46 percent on transmission paths sinking at the Hudson Valley Zone as the day-ahead congestion revenues that accrued on the transmission paths from the Capital Zone to the Hudson Valley Zone fell nearly 90 percent from 2017 to 2018. These results show that the TCC prices generally reflect the anticipated levels of congestion at the time of auctions.

The profits and losses that TCC buyers netted on most transmission paths have been generally consistent with changes in day-ahead congestion patterns from previous like periods. In addition, the past TCC auction results generally show that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month auction to the monthly auction. This is expected since more accurate information is available about the state of the transmission system and likely market conditions in the auctions that occur closer to the actual operating period. Since 100 percent of the capability of the transmission system 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.

VI. 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 external resources to compete to serve consumers who would otherwise be limited to higher-cost internal resources;
- Low-cost internal resources to compete to serve load in adjacent areas; 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.

New York 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 eight controllable lines that are collectively able to import up to roughly 3.6 GW directly to downstate areas.[69,70] Hence, New York's total import capability is large relative to its load, making it important to schedule the interfaces efficiently.

A. Summary of Scheduling Pattern between New York and Adjacent Areas

Table 11 summarizes the net scheduled imports between New York and neighboring control areas in 2017 and 2018 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[71] Total net imports from neighboring areas averaged nearly 3.2 GW during peak hours in 2018, comparable to the levels seen in 2017.

Table 11: Average Net Imports from Neighboring Areas
Peak Hours, 2017 – 2018

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2017	1,332	863	344	-416	234	563	64	156	33	3,173
2018	1,372	733	442	-564	164	561	30	201	253	3,192

69 The controllable lines are: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, the Neptune Cable, and three lines known as the A, B, and C lines.

70 The A, B, and C lines (which interconnect NYC to New Jersey) were used to flow 1,000 MW from upstate New York through New Jersey into NYC under the ConEd-PSEG wheeling agreement prior to May 1, 2017. Currently, these lines are scheduled as part of the primary PJM to NYISO interface and are also operated under M2M JOA with PJM in real-time, although the B and C lines have been out-of-service since January 2018 with no scheduled return date. These lines are further evaluated in Sections IX.E and IX.F.

71 Figure A-58 to Figure A-61 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

Controllable Interfaces

As in prior years, imports from neighboring control areas satisfied slightly more than 30 percent of the demand on Long Island in 2018. The Neptune line was typically fully scheduled during daily peak hours absent outages/deratings. Net imports over the Cross Sound Cable and the 1385 line varied in a manner similar to the primary New England interface – lower in the winter when natural gas prices in New England were much higher than natural gas prices on Long Island.

Net imports to New York City over the Linden VFT and the HTP interfaces rose from an average of 190 MW during peak hours in 2017 to 455 MW in 2018. The increase was driven by: (a) the return of the HTP interface from a lengthy outage that ended in November 2017; and (b) higher LBMPs in the 345 kV system of New York City for reasons discussed in Section II.E. Net imports across these two controllable interfaces typically rise in the winter months when natural gas prices in New York tend to rise relative to those in New Jersey.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces fell 7 percent from roughly 2,125 MW in 2017 to 1,985 MW in 2018 during peak hours. Net imports from Hydro Quebec to New York accounted for nearly 70 percent of net imports across the primary interfaces in 2018. Variations in Hydro Quebec imports are normally caused by transmission outages on the interface.[72]

Average net imports from Ontario fell 15 percent from 2017 to 2018 partly because of higher prices on the Ontario side.[73] In addition, the decrease also reflected more frequent congestion in real time on the 230+ kV network in the West Zone in 2018.[74] Import limitations were still used by the NYISO to manage congestion on internal 115 kV constraints in Western New York. However, this operating procedure was ended in December 2018 when the NYISO started to model 115 kV constraints in the day-ahead and real-time markets.

Net imports from PJM and New England across their primary interfaces varied considerably, tracking variations in gas price spreads between these regions. For example, New York normally has higher net imports from PJM and higher net exports to New England in the winter, consistent with the spreads in natural gas prices between these markets in the winter (i.e., New England >

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72 Imports from HQ were high in most months of 2018 but fell notably in April and October when the interface was OOS for 7 and 15 days, respectively.

73 For example, the Ontario clearing price (“HOEP”) averaged $19/MWh in the second quarter of 2018 compared to $6/MWh in the second quarter of 2017.

74 Ontario imports are upstream of transmission constraints in the West Zone therefore are usually bottlenecked during congested intervals.

New York > PJM). Overall, New York was typically a net importer from PJM and a net exporter to New England across their primary interfaces. Both net imports from PJM and net exports to New England increased from 2017 to 2018, consistent with larger gas spreads between these markets. However, some lengthy key transmission outages on the two interfaces limited the increases.[75]

B. Unscheduled Power Flows around Lake Erie

Unscheduled power flows (i.e., loop flows) around Lake Erie have significant effects on power flows in the surrounding control areas. Loop flows that move in a clockwise direction generally exacerbate west-to-east congestion in New York, leading to increased congestion costs. Although average clockwise circulation has fallen notably since the IESO-Michigan PARs went into service in April 2012, large fluctuations in loop flows are still common.[76]

Our analysis shows a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows.[77] Congestion in the West Zone became more frequent in 2018 partly because loop flows shifted from an average of nearly 30 MW in the *counter-clockwise* direction in 2017 to approximately 0 MW in the *clockwise* direction in 2018.

West Zone congestion is relatively infrequent, but it tends to be very severe when it does occur. The congestion value on 230 kV constraints exceeded $200,000 in just 0.04 percent of intervals in 2018, although these intervals with severe congestion accounted for nearly 20 percent of the total priced congestion value in the West Zone in 2018.[78] The sporadic but severe pattern of congestion in the West Zone makes it particularly important to manage congestion efficiently. The NYISO implemented two market enhancements in December 2018 that will reduce the severity of congestion that results from loop flows through in the West Zone: (a) modeling 115 kV West Zone constraints in the day-ahead and real-time markets; and (b) modeling the Niagara plant in a manner that recognizes that the distribution of output from 115 and 230 kV units at the plant can reduce congestion management costs.

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75 The B and C PAR-controlled lines (part of the primary interface) were OOS for almost the entire year of 2018, limiting flows from PJM to New York City across its primary interface. The New Scotland-Alps and the Long Mountain-Pleasant Valley 345 kV lines were OOS in various periods of 2018 for a total of roughly four months, during which the NY/NE interface was reduced to around 500 MW.

76 These PARs are generally operated to better conform actual power flows to scheduled power flows across the Ontario-Michigan interface. The PARs are capable of controlling up to 600 MW of loop flows around Lake Erie, although the PARs are generally not adjusted until loop flows exceed 200 MW. Use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

77 See Section III.D in the Appendix for more details.

78 Congestion value is a measure of real-time flow over a constraint times the shadow price of the constraint. The quantity is used to quantify congestion in Section II.E and Section V.A.

In addition to the effects of loop flows on West Zone congestion, we also discuss the effects on: (a) inconsistencies between RTC and RTD in Subsection D; (b) the transient congestion (along with other factors that are not explicitly modeled in the dispatch software) in Section IX.G; and (c) the day-ahead and balancing congestion shortfall uplift in Section V.A.

C. Efficiency of External Scheduling by Market Participants

We evaluate external transaction scheduling between New York and the three adjacent control areas with real-time spot markets (i.e., New England, Ontario, and PJM) in 2018. As in previous reports, we find that while external transaction scheduling by market participants provided significant benefits in a large number of hours, the scheduling did not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading.

Table 12 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets in 2018.[79] Participant-scheduled transactions flowed in the efficient direction (i.e., from lower-priced area to higher-priced area) in more than half of the hours on most interfaces between New York and neighboring markets, resulting in a total of $157 million in production cost savings during 2018.

Table 12: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2018

	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	-680	$1.42	42%	-$6	101	$1.53	55%	$7
Ontario	762	$10.97	85%	$86	46	$11.31	56%	$2
PJM	336	-$1.04	63%	$1	22	-$1.01	61%	$6
Controllable Ties								
1385 Line	41	-$0.03	70%	$3	-17	-$0.13	52%	$1
Cross Sound Cable	153	$0.15	74%	$5	-0.2	$0.63	55%	-$0.2
Neptune	541	$7.82	88%	$33	0.0	$7.60	55%	$0.4
HTP	177	$1.85	77%	$6	45	$2.74	62%	$2
Linden VFT	151	$4.20	89%	$9	45	$0.41	60%	$2

In the day-ahead market, the share of hours with efficient scheduling was generally high for the five controllable ties because there is a relatively high level of certainty regarding the price differences across these controllable lines. A total of $56 million in day-ahead production cost savings was achieved in 2018 across the five controllable ties. The Neptune Cable accounted for

79 See Section IV.B in the Appendix for a detailed description of this table.

nearly 60 percent of these savings because the interface was generally fully scheduled and the New York price was roughly $7.8 per MWh higher on average in 2018.

Likewise, day-ahead transactions between Ontario and New York flowed in the efficient direction in 85 percent of hours. This was largely because the price on the New York side was consistently higher by an average of $11 per MWh in 2018. As a result, a total of $86 million in production cost savings was achieved across the Ontario interface in the day-ahead market. [80]

The right panel in the table evaluates how participants adjusted their transactions in response to real-time prices, indicating that these adjustments were efficient in well over half of the hours. Real-time adjustments were generally more active at the interfaces with CTS ("Coordinated Transaction Scheduling", including the NY/NE primary interface and all four interfaces with PJM), resulting in a total of $18 million savings in production costs during 2018. However, real-time adjustments across other controllable ties were less frequent, resulting in significantly lower production cost savings.[81]

We evaluate real-time price convergence between New York and neighboring areas (in Section IV.B in the Appendix) and find that price convergence between New York and New England was better at the CTS interface (i.e., the primary interface) than at the hourly-scheduled 1385 Line, suggesting that CTS helped improve the utilization of the interfaces. In addition, the evaluation also shows that the price convergence at the NY/NE CTS interface was better than at the primary NY/PJM CTS interface, reflecting better performance of CTS with ISO-NE.

Although significant benefits have been achieved in the majority of hours, there was still a large number of hours when power flowed in the inefficient direction on all of the interfaces or when large amounts of additional efficient flows could have been scheduled. These results indicate how uncertainty and other costs and risks interfere with efficient interchange scheduling, which also underscores the value of having a well-functioning CTS process.

D. Evaluation of Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") is a market process whereby two neighboring RTOs exchange and use real-time market information to clear market participants' intra-hour external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the hourly LBMP-based scheduling system.

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80 The price difference is over-stated because the HOEP ("Hourly Ontario Energy Price") used for these calculations understates the Ontario price when there is congestion to the border on the Ontario side. Therefore, the production cost savings is over-estimated.

81 Many of the adjustments resulted from curtailments or checkout failures of a day-ahead transaction, which sometimes raises production costs modestly.

- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.
- CTS bids are evaluated relative to the neighboring ISO's short-term price forecast, while the previous system required market participants to forecast prices in the adjacent market (more than 75 minutes in advance).
- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established 45 to 105 minutes in advance, while schedules are now determined 15 minutes ahead when more accurate system information is available.

CTS was first implemented with PJM on November 4, 2014 and with ISO-NE on December 15, 2015. 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.

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 11 evaluates the price-sensitivity of bids at the PJM and ISO-NE interfaces, showing the average amount of bids at each interface during peak hours (i.e., HB 7 to 22) in 2017 and 2018.[82] Only CTS bids are allowed at the ISO-NE interface, while CTS bids and LBMP-based bids are used at the PJM interface. Thus, 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.[83]

The average amount of price-sensitive bids at the PJM interface was significantly lower than at the New England interface in 2017 and 2018. In 2018, an average of 612 MW (including both imports and exports) were offered between -$10 and $5 per MWh at the New England interface, substantially higher than the 254 MW offered at the PJM interface. Likewise, the amount of cleared price-sensitive bids at the New England interface was nearly double the amount cleared at the PJM interface.

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. Typically, the NYISO charges physical exports to PJM at a rate ranging from $4 to $8 per MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than $3 per MWh. These charges are a significant economic barrier to achieving the potential benefits from the CTS

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82 Figure A-63 in the Appendix shows the same information by month for 2018.

83 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.

process, since large and uncertain charges deter participants from submitting efficient CTS offers at the PJM border. This is particularly evident from the fact that almost no CTS export bids were offered at less than $5 per MWh at the PJM border.

Figure 11: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2017-2018

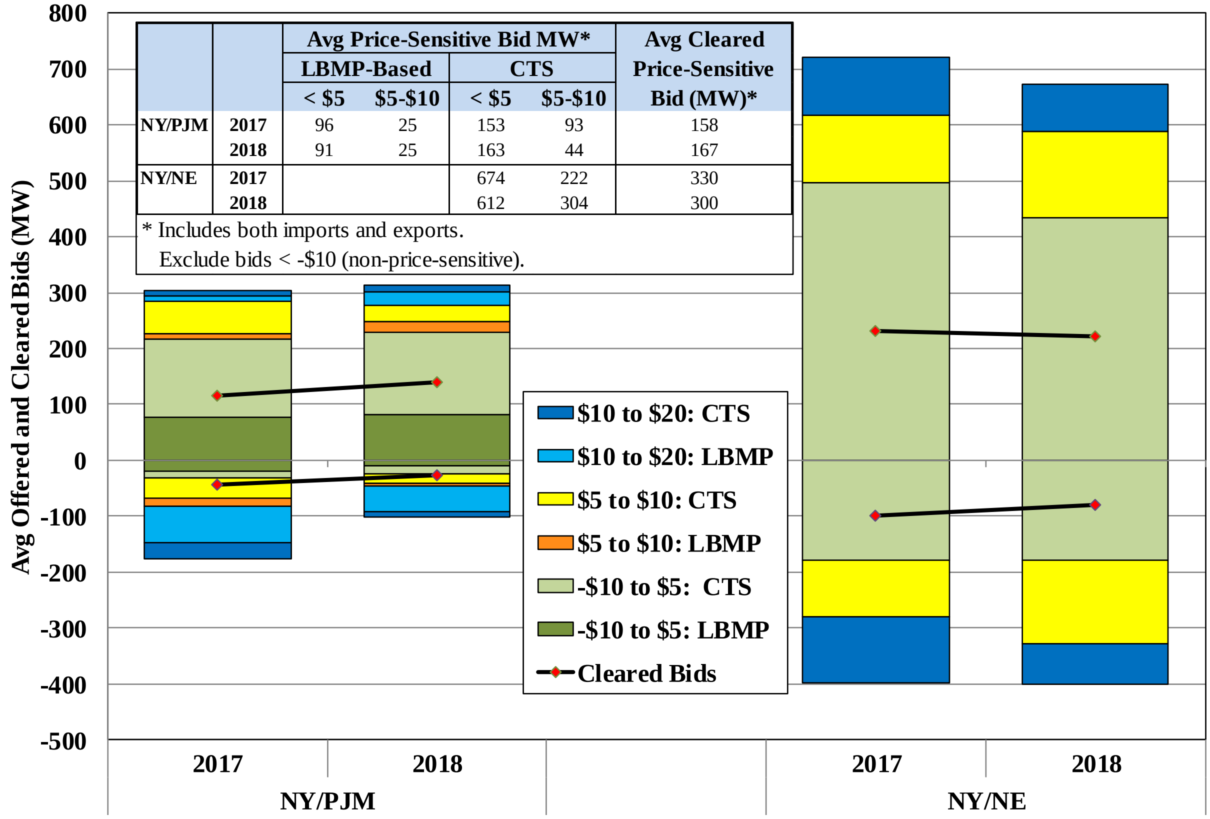


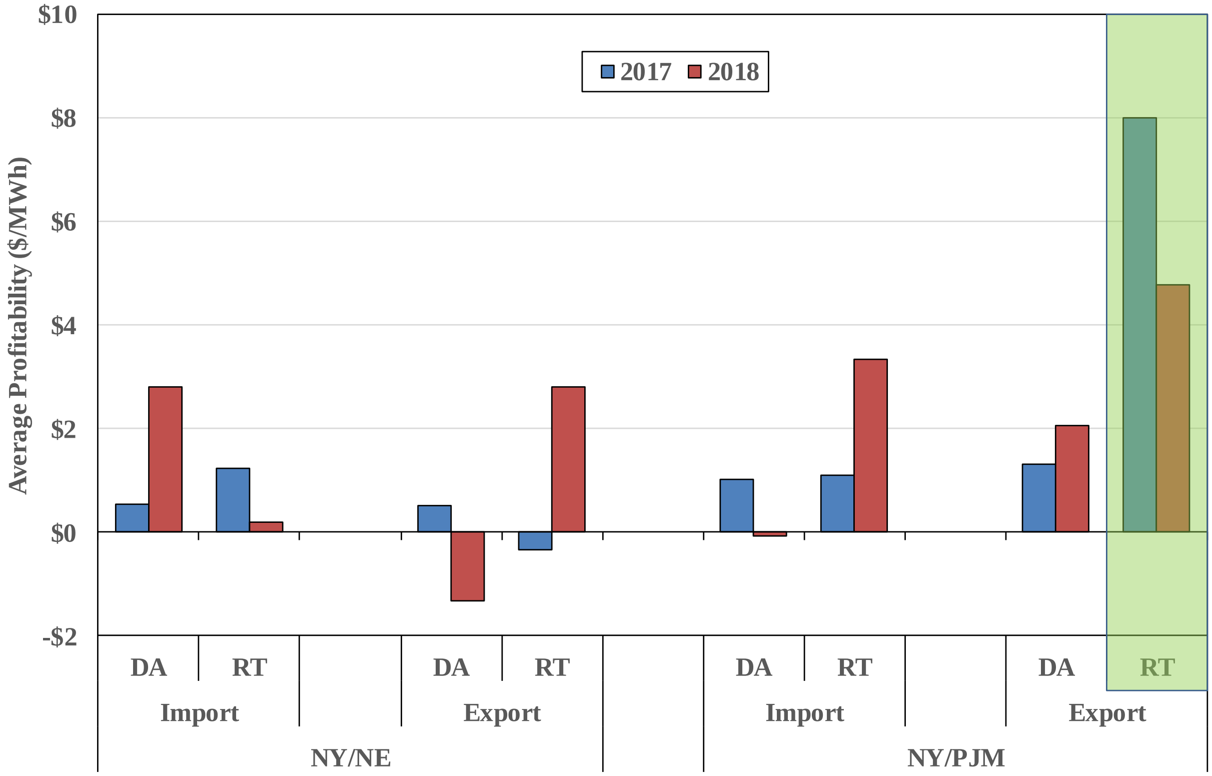
Figure 12 examines the average gross profitability of scheduled transactions (not including fees mentioned above) at the two CTS interfaces in 2017 and 2018.[84] The gross profitability of scheduled transactions (including both imports and exports) averaged roughly $0.8 per MWh over the two-year period at the primary New England interface, indicating this is generally a low-margin trading activity.

At the PJM border, the average gross profitability was modestly higher for scheduled imports (which usually incur fees of less than $3 per MWh) and far higher for scheduled exports (which incur fees ranging up to $8 per MWh). In particular, the average gross profit for real-time exports to PJM was $8 per MWh in 2017 and close to $5 per MWh in 2018 (see the shaded area in the figure), indicating that participants will only schedule these transactions when they anticipate that the price spread between markets will be large enough for them to recoup the fees

84 Figure A-64 in the Section IV.C of the Appendix also shows the average amount of scheduled transactions in each category.

that will be imposed on them. We can infer that market participants frequently anticipate smaller price spreads but that they do not arbitrage price differences when they anticipate that the price difference is likely to be smaller than the transaction fee.

Figure 12: Average Gross Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2017-2018



Day-ahead exports to PJM exhibited a much lower gross profitability than real-time exports because most of the day-ahead exports were scheduled by participants with long-standing physical contract obligations, making them insensitive to the large export fees.

These results demonstrate that imposing large transaction fees on low-margin trading dramatically reduces trading and liquidity. Hence, we recommend eliminating these charges at the interfaces between New York and PJM.[85]

85 See Section XI, Recommendation #2015-9.

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.[86]

We estimated that $6.3 million and $4.8 million in production cost savings were anticipated based on information available when RTC determined final interchange schedules at the New England and PJM interfaces in 2018.[87] The potential savings were 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. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that:

- $5.5 million of potential savings were realized at the New England interface; and
- $0.7 million were realized at the PJM interface.

The overall performance of CTS at the New England border improved modestly in 2018 as the estimated realized savings increased from $4.8 million in 2017 to $5.5 million in 2018. This improvement was partly due to better price forecasting at both sides of the border, where NYISO forecasting errors improved from 25 percent in 2017 to 24 percent in 2018 and ISO-NE forecasting errors improved from 24 percent to 20 percent. However, the actual production cost savings at the PJM border did not change much from 2017 to 2018 ($0.6 million in 2017 compared to $0.7 million in 2018). Although NYISO forecasting errors at the PJM border improved from 28 percent in 2017 to 26 percent in 2018, PJM forecasting errors worsened from 27 percent to 35 percent.

In addition, we found that the unrealized savings were much larger in periods when the forecast errors exceeded $20 per MWh, while they were much smaller when the forecast errors were modest. Most of the unrealized savings at the two interfaces occurred in a small number of intervals with large forecast errors.

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.

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

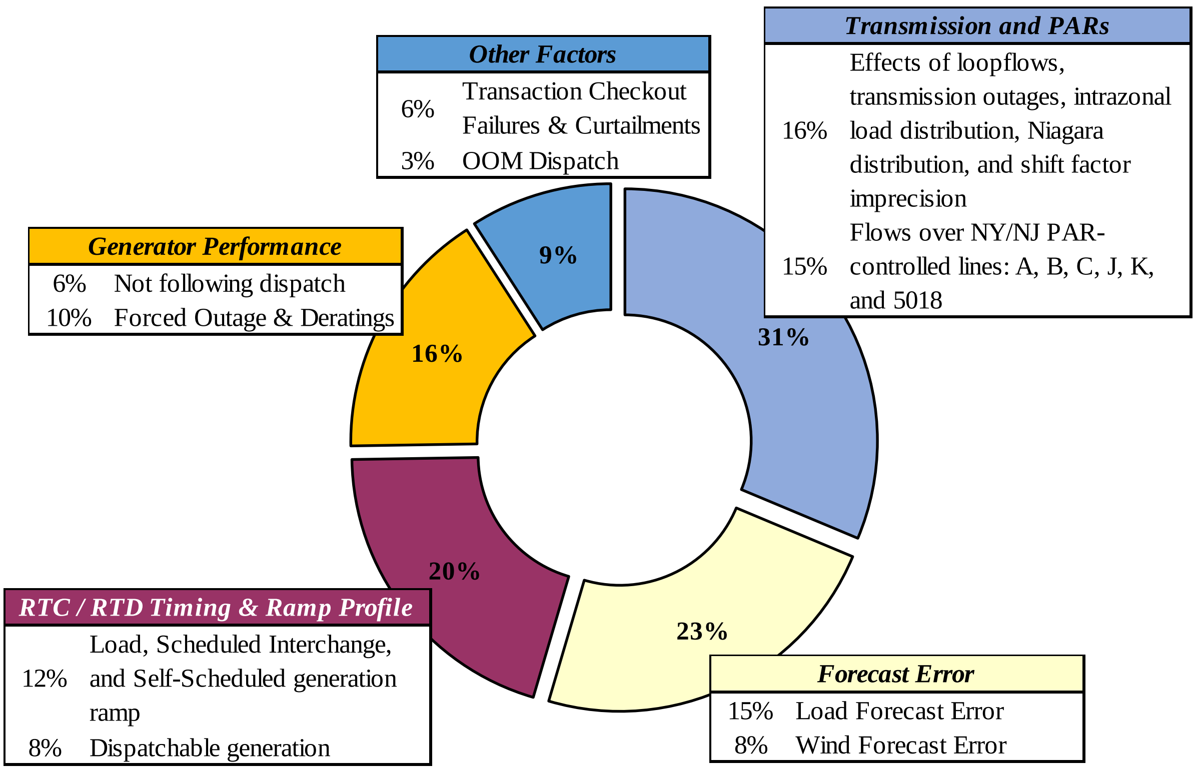
87 Our evaluation tends to under-estimate the production cost savings, because the hourly schedules that we estimate would have occurred without CTS reflect some of the efficiencies that result from CTS.

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 2018. 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.[88] We expect that this evaluation will be useful as the NYISO and stakeholders prioritize different projects to improve market performance.

Figure 13 summarizes the RTC/RTD divergence metric results for "detrimental" factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2018.[89]

Figure 13: Detrimental Factors Causing Divergence Between RTC and RTD
2018



88 See Section IV.D in the Appendix for a detailed description of this metric (illustrated with examples).

89 Section IV.D in the Appendix also shows our evaluation of "beneficial" factors that reduce differences between RTC and RTD prices.

Our evaluation identified three primary groups of factors that contributed most to RTC price forecast errors in 2018.[90] First, transmission network modeling issues were the most significant category, accounting for 31 percent of the divergence between RTC and RTD in 2018. In this category, key drivers include:

- Errors in the forecasted flows over PAR-controlled lines between the NYISO and PJM (i.e., the 5018, ABC, 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 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. However, the errors from this group of PARs fell in 2018 primarily because the B and C lines were out of service for almost the entire year.
- 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.

Second, errors in load forecasting and wind forecasting were another large contributor to price differences between RTC and RTD. This accounted for 23 percent of the overall divergence between RTC and RTD in 2018.[91]

Third, the next largest category, which accounted for 20 percent of the divergence between RTC and RTD prices in 2018, 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 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).[92]

We have made recommended improving the accuracy of the forecast assumptions by RTC to facilitate more efficient interchange scheduling.

- Recommendation #2014-9 is to: (a) enhance the forecast of loop flows such as by introducing a bias into RTC that accounts for the fact that over-estimates of loop flow are less costly on average than under-estimates, and (b) reduce variations in unmodeled flows by modeling the effects of generation redispatch and PAR-control actions on the flows over PAR-controlled lines.

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90 See Section IV.D in the Appendix for a detailed list and discussion of "detrimental" and "beneficial" factors.

91 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.

92 Figure A-69 in Section IV.D of the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transactions.

- Recommendation #2012-13 is to bring consistency between the ramp assumptions used in RTC versus RTD. A list of potential changes is listed in Section XI.B.

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. However, its importance will increase significantly in the future because:

- The NYISO is exploring the possibility of scheduling the Ontario interface every 15 minutes; and

RTC is also responsible for scheduling flexible generators that can start-up in 45 minutes or less. As 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 that must be deployed based on a short-term forecast of system conditions. A better-performing RTC will more efficiently schedule flexible resources in timely response to quick changes in system conditions, which are critical for successful integration of renewables.

VII. Capacity Market Results and Design

The capacity market is designed to ensure that sufficient capacity is available to meet 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 summarizes the capacity market results, discusses the cost of reliability improvement from additional capacity, and proposes new rules to better reflect the value of resources that provide significant planning reliability benefits to New York.

A. Capacity Market Results in 2018

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices.[93] Table 13 shows average spot auction prices for each locality for the 2018/19 Capability Year and year-over-year changes in key factors from the prior Capability Year.

Table 13: Capacity Spot Prices and Key Drivers by Capacity Zone [94]
2018/19 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2018/19 Margin (% of Requirement)	7.7%	6.8%	11.2%	10.2%
Net Change from Previous Yr	-1.5%	1.0%	2.4%	1.1%
Average Spot Price				
2018/19 Price ($/kW-yr)	$1.92	$5.76	$5.76	$3.80
Percent Change Yr-Yr	48%	-14%	-15%	3%
Change in Demand				
Load Forecast (MW)	-275.3	-143.7	-131.3	-51.4
IRM/LCR	0.2%	3%	-1%	0%
UCAP Requirement (MW)	49	479	-465	-88
Change in UCAP Supply (Summer)				
Generation (MW)	124.3	519	-400.8	-38
SCR (MW)	85.6	135	101.8	-2
Import Capacity (MW)	-701.7			
Change in Demand Curves (Summer)				
Reference Price Change Yr-Yr	11%	11%	12%	12%
Net Change in Derating Factor Yr-Yr	-0.7%	-1.1%	2.7%	0.7%

93 Based on the Capacity Demand Curves for the 2018/19 Capability Year, a 100 MW change in ICAP supply or demand would change the clearing price by: $0.22/kW-month in NYCA, $0.73/kW-month in the G-J Locality, $1.25/kW-month in New York City, and $1.42/kW-month in Long Island.

94 See Section VI in the Appendix for more details.

Capacity prices rose in Long Island and NYCA, while they fell in NYC and the G-J Locality. These changes were driven by variations in supply and demand and annual updates to the ICAP Demand Curves which raised each curve by 11 to 12 percent. Key factors include:

- In Western New York, spot prices rose by 48 percent primarily due to a significant reduction of imports, especially from PJM. New capacity additions, especially that of the CPV Valley Energy Center, helped to mitigate the impact reduction in imports.
- In the G-J Locality, spot prices fell by 14 percent due mainly to the addition of the CPV Valley combined cycle and the Bayonne CTs, although a 3 percent increase in the LCR and the exit of Ravenswood units mitigated the magnitude of the price decline.
- In New York City, spot prices fell by 15 percent primarily because of a lower LCR value (1 percentage point) and lower peak load forecast. The NYC prices in the 2018/19 Capability Year were determined by the G-J Demand Curve in all 12 months of the year.
- In Long Island, spot prices rose by 3 percent largely because of the increased demand curve reference point.

Peak load forecasts continued the recent trend, declining 0.5 to 1.5 percent in each area. Thus, ICAP requirements fell in each area except the G-J Locality, where the LCR increased 3 percent.

B. Cost of Reliability Improvement from Additional Capacity

Capacity markets should be designed to provide efficient price signals that reflect the value of additional capacity in each locality. This will direct investment to the most valuable locations and reduce the overall capital investment cost necessary to satisfy the "one day in ten year" planning reliability standard. In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the 2019/20 Capability Year using a new methodology.

Capacity markets should provide price signals that reflect the reliability impact and cost of procuring additional capacity in each location. Specifically, we define two quantities that can be used to quantify the costs and reliability benefits of capacity:

- Marginal Reliability Impact ("MRI") – The estimated reliability benefit (i.e., reduction in the annual loss of load expectation ("LOLE")) from adding 100 MW of UCAP to an area.
- The Cost of Reliability Improvement ("CRI") is the estimated capital investment 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 from the latest demand curve reset study and the MRI of capacity in a particular location.

Under an efficient market design, 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, it implies that cost savings would result from shifting purchases from a high-cost zone to a low-cost zone.

The NYISO recently implemented the new Optimized LCRs Method, which seeks to minimize capacity procurement costs: (a) assuming the system is at an LOLE of 0.1 days per year over the long-term, (b) while taking the NYSRC-determined IRM as given, and (c) imposing minimum transmission security limits ("TSL") for each locality. 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 select the lowest cost supply to satisfy reliability. Minimizing investment costs is efficient because it selects the lowest cost resources (just as the real-time market selects the lowest cost resources to satisfy load and ancillary services requirements).

Table 14 shows the estimated MRI and CRI for each load zone and for three additional locations (CPV VEC, Athens/Gilboa and Staten Island) that are represented as distinct locations in the GE-MARS topology that is used for the IRM process.[95]

Table 14: Marginal Reliability Impact and Cost of Reliability Improvement by Locality
2019/20 Capability Year

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*
A	$98		0.059	0.003	$3.5
B	$98		0.057	0.004	$2.4
C	$98		0.057	0.004	$2.4
D	$98		0.057	0.004	$2.4
E	$98		0.057	0.004	$2.4
F	$98	0.061	0.057	0.004	$2.4
G	$148		0.056	0.005	$2.7
H	$148		0.056	0.006	$2.7
I	$148		0.056	0.006	$2.6
J	$180		0.054	0.008	$2.3
K	$134		0.055	0.006	$2.2
Other Areas					
CPV VEC	$148		0.056	0.005	$2.9
Athens Gilboa	$98	0.061	0.058	0.003	$3.0
Staten Island (J3)	$180		0.060	0.001	$12.9

The Optimized LCRs Method has reduced the range in CRI values across load zones compared to previous years. Nevertheless, the range between the minimum CRI-value location of Zone K (i.e., Long Island at $2.2 million per 0.001 events) and the maximum CRI-value location of Zone A (i.e., West Zone at $3.5 million per 0.001 events) is still significant. However, some have asserted that the Net CONE for Zone K was under-estimated in the last demand curve reset, suggesting that the true CRI for Zone K may actually be higher.

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

The results reveal substantial differences in the MRI values for specific areas within a capacity zone. For instance, the MRI for Staten Island is only 0.001—significantly lower than the Zone J MRI. The MRIs for CPV VEC and Athens/Gilboa are also lower than the MRIs of their respective capacity zones. This disparity suggests that generation in these areas is over-priced.

The CRI values are similar across zones within each capacity region (i.e., Zones G-I and Zones A-F) with the notable exception of Zone A. Large disparities within a region imply it should be broken into multiple regions to ensure that capacity is priced efficiently. However, the MRI and the CRI for each zone depend on several factors that could evolve in the future, including:

- The retirement of Indian Point, which will lead to disparities between Zones G and H,
- The Western New York public policy transmission project, which will tend to eliminate disparities between Zones A and B, and
- Recognition in the demand curve reset of lower net new entry costs in central New York would reveal disparities between Zones A to E and Zone F.[96]

Although the new Optimized LCRs Method was an enhancement, additional improvements are possible. Accordingly, in subsection D, we discuss our recommendation for improving the efficiency of prices in the capacity market, while making the capacity market simpler to administer and more adaptable to changing system conditions.

This subsection introduces two concepts for evaluating the efficiency of prices in the capacity market: the MRI, which quantifies the impact on reliability of capacity in a particular area; and the CRI, which relates the reliability impact of capacity to the net cost of new entry in each area. The next three subsections apply these concepts to support recommendations in three areas. Subsection C recommends a framework for compensating transmission investments for the capacity value of the transmission, Subsection D recommends a mechanism for setting prices in the capacity market that is simpler and more efficient than the current processes, and Subsection E recommends techniques for quantifying the capacity value of new transmission projects in the NYISO's transmission planning processes.

C. 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. To provide efficient incentives to invest in transmission, we recommend that transmission developers receive financial capacity transfer rights ("FCTRs") for upgrades.[97] The value of the

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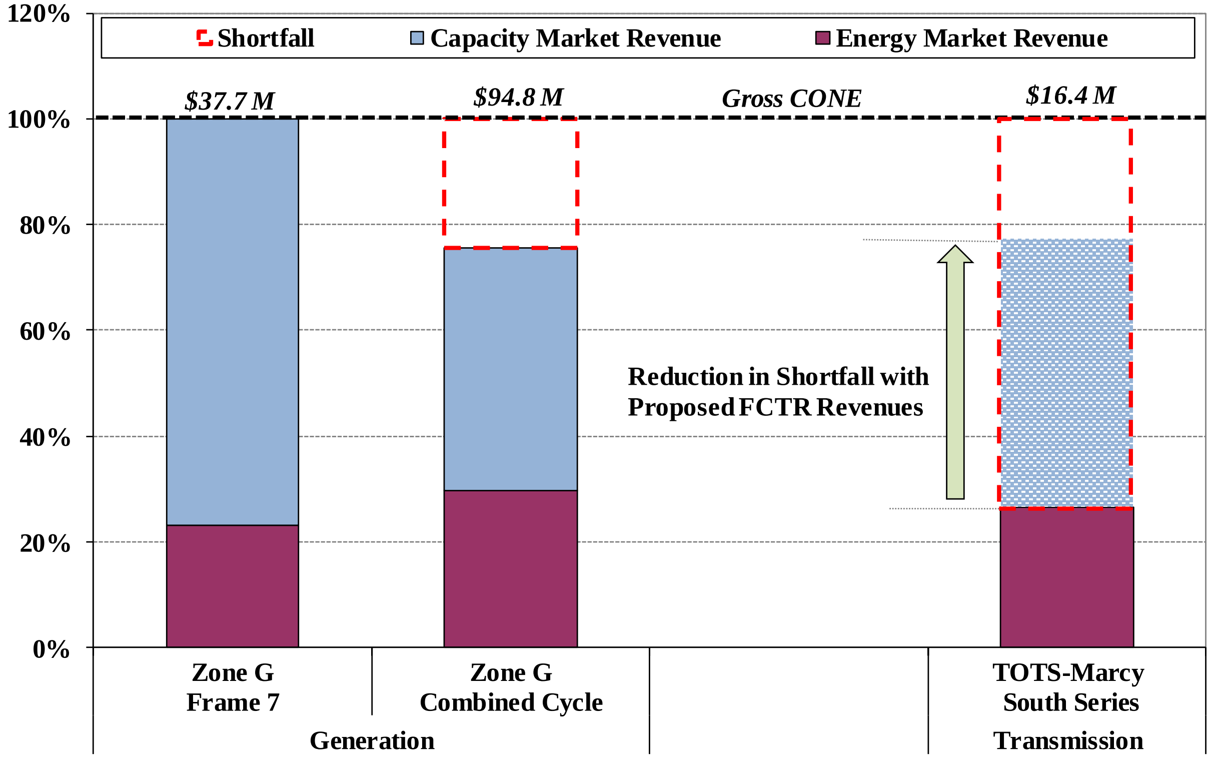
96 See comments of the Market Monitoring Unit in Commission Docket ER17-386-000, dated December 9 2016.

97 See Recommendation #2012-1c in Section XI.

rights should be based on how much installed capacity requirements are reduced by the upgrade. This subsection analyzes how FCTRs might affect a transmission investment decision.

Figure 14 shows the contributions from capacity revenues and energy and ancillary services revenues that would be received by the hypothetical demand curve unit in Zone G at demand curve reset conditions (i.e., assuming the G-J Locality was at the Level of Excess ("LOE") modeled in the demand curve reset) compared to the levelized CONE of the project. The table shows the comparable information for the Marcy-South Series Compensation ("MSSC") portion of the TOTS project. For the MSSC project, the table reports the Incremental TCC revenues received by the project under "Energy Market Revenue." The table reports capacity value (i.e., the revenue that a generator or demand response resource would receive for having the same effect on LOLE) of increased transfer capability in the resource adequacy model under "Capacity Market Revenue."[98] Transmission projects do not receive actual revenue for this capacity value.

Figure 14: Valuation of Generation and Transmission Projects at DCR Conditions
Annualized Cost of New Entry vs. Revenue



The results illustrate the disadvantages that transmission projects have relative to generation in being compensated for the benefits they provide to the system. Capacity markets provide a critical portion of the incentive (up to 77 percent) for a new generator in Zone G. In the absence of capacity payments to the MSSC project, the project would recoup only 27 percent of its

98 See Appendix Section VI.G for the assumptions and inputs underlying the data shown in the table.

annualized gross CONE. However, granting FCTRs to the project based on its capacity value would have provided an additional 51 percent of the annualized gross CONE. 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.

Similarly, it would also be appropriate to compensate (or charge) new generation projects for their impact on deliverability constraints through capacity transfer obligations (i.e., negative-value FCTRs). In some cases, it would be more efficient (i.e., cost-effective) for a project developer to accept negative FCTRs than make transmission upgrades (if the value of upgrading the transmission system was lower than the cost of the upgrades). Such compensation would provide incentives to interconnect at points that increase the deliverability of other generators. Such charges would be more efficient than assigning SDU costs, since these can be a barrier to efficient investment if the SDU costs are higher than the value of the upgrade.

D. Optimal Locational Marginal Cost Pricing of Capacity Approach

As discussed in subsection B, in an efficient capacity market, prices should be aligned with the reliability value of capacity in each locality. In our previous State of the Market reports we have identified several issues that prevent the existing capacity market framework from setting prices consistent with this principle.

In this subsection, we highlight concerns with the existing framework for pricing capacity, propose an alternative approach to setting capacity prices, and discuss how our approach would address the concerns with the existing framework. Our approach to capacity pricing would:

- Reduce the costs of satisfying resource adequacy needs,
- Provide efficient incentives for investment under a wide range of conditions,
- Improve the adaptability of the capacity market to future changes in transmission network topology and in the resource mix, and
- Reduce the complexity of administering the capacity market as the system evolves.

Issues with Current Capacity Market Framework

The current framework for determining capacity prices involves estimating Net CONE and creating a demand curve for each existing locality, determining the optimal 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 relative to the prevailing demand curve. This approach can result in misalignment between the value and compensation of capacity for some types of capacity in some locations. We summarize below several aspects of the current framework that can lead to inefficient capacity market outcomes.

- The NYISO currently sets the LCRs by minimizing the total procurement cost of capacity in a specific scenario where the system is "at criteria" (i.e., an LOLE of 0.10). However, this does not guarantee that capacity prices are efficient under the surplus capacity conditions that typically prevail.
- The rules for creating New Capacity Zones will not lead to the timely creation of a new capacity zones in several circumstances (e.g., after Indian Point retires).[99] This delay could lead to prices that do not reflect critical resource adequacy needs in some areas. Furthermore, the current rules cannot accommodate differences in pricing within an existing load zone.
- The NYISO's current approach to compensating non-conventional technologies (e.g. battery storage and intermittent resources) relies on periodic studies. These updates are based on resource mix assumptions that do not always represent the penetration levels and/or geographical distribution of the new technologies. Therefore, compensation for new technologies may not be consistent with their actual reliability value.
- Under the NYISO's Optimized LCRs method, the LCRs depend directly on the Net CONE estimate for each zone. Hence, errors in estimating the Net CONEs can lead to an inefficient allocation of capacity across zones.
- The NYISO currently allocates the cost of capacity based on where the capacity is located rather than to the load customers that benefit from the capacity.
- The market does not accurately reflect the value of imports, and the NYISO's approach to accounting for exports from an import-constrained zone relies on a deterministic power flow analysis instead of a probabilistic MARS-based method. Consequently, the basis for pricing import and export transactions is inconsistent with the basis for valuing internal capacity sales.[100]

Proposed Locational Marginal Pricing of Capacity ("C-LMP") Framework

We propose NYISO transition to our proposed C-LMP Framework, which would involve:

- Eliminating all existing capacity zones;
- Establishing pricing nodes throughout the State and for each external interface;
- Clearing the capacity market with an auction engine that will include the planning criteria and constraints, which will optimize the capacity procurements at all locations.
- Set locational capacity prices that reflect the marginal capacity value at each location.

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99 See section VII.F of the 2017 State of the Market for the NYISO.

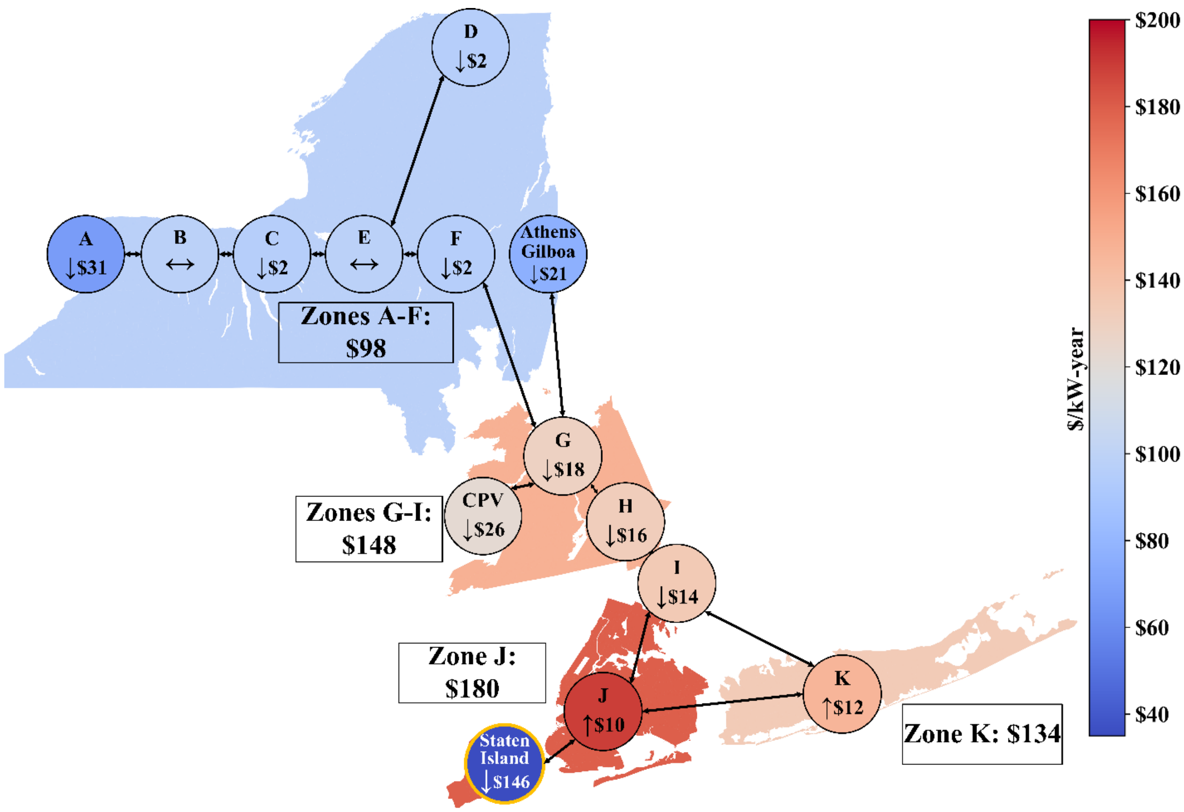
100 See section VII.C of the 2017 State of the Market for the NYISO.

From an administrative standpoint, the C-LMP method involves estimating one key market parameter every four years (concurrent with the Demand Curve reset study) – the optimal level of CRI, which is estimated in a manner similar to the Optimized LCRs method. Under this approach, the spot market prices are determined by the optimal CRI level and the incremental reliability impact of a resource under as-found conditions at the time of the auction.[101]

To illustrate the inefficiencies with the current pricing framework, we estimated the capacity prices using the C-LMP approach and compared them with the current pricing at the LOE conditions (see Figure 15).[102] The colors in the geographical map represents capacity prices under the current framework for each of four localities with each price shown in a rectangular box. The colors of each bubble represents locational prices under the C-LMP approach. Each bubble shows the name of the zone/location (in the latest IRM study topology) and the difference between the clearing price under the C-LMP approach versus the existing framework.

Figure 15: Capacity Prices at the Level of Excess

Existing vs. Proposed Framework



[101] See Recommendation #2013-1c in Section XI. A more detailed description of the C-LMP approach was presented in *Concept for Locational Capacity Pricing Based on Marginal Reliability Impacts and Costs* at the Installed Capacity Working Group meeting on June 22, 2017.

[102] Our estimated capacity prices under the C-LMP approach assume a CRI* of 2.4 MM$ per 0.001 change in LOLE. The capacity price for a zone z is then calculated as the product of CRI* and MRI_z (see Table 14).

The capacity price in each location under the C-LMP approach, by definition, is more aligned with the marginal reliability value of additional capacity in that location. These results highlight the misalignment between prices and value in several locations under the current framework. In particular, the resources in the Staten Island area appear to be vastly over-priced. Similarly, resources in some generation bubbles (i.e., CPV and Athens/Gilboa) also appear to be over-compensated under the existing framework. Furthermore, the prices in Zones A and G-I may decline, while Zone K prices may increase under the C-LMP approach.

The C-LMP pricing approach would be less administratively burdensome because it would require fewer approximations and simplifying assumptions than either the current framework for determining capacity market parameters and prices. Changes in the network topology that result from new transmission investment and generation additions and retirements would transfer seamlessly from the planning models to the capacity price-setting mechanism without the NYISO having to explicitly create or eliminate new zones, define additional demand curves, and other administratively burdensome aspects of the current capacity market.

The C-LMP framework will be simpler to administer as the system adapts to the entry of large amounts of new technologies. New technologies provide significant reliability benefits but also have a range of characteristics that need to be accounted for efficiently, including: (a) intermittency that is correlated with other resources of the same technology or location, (b) energy storage limitations that limit the duration of output during peak conditions, and (c) small-scale distributed resources that reduce the potential effects of supply contingencies during peak conditions.[103] Furthermore, since the C-LMP framework approach sets prices in each area based on its MRI relative to other areas (rather than individual Net CONE values for each area), any bias in the estimation of Net CONE will not bias the distribution of capacity across different areas.

Finally, by utilizing a different settlement mechanism for loads and transmission than supply resources, the C-LMP approach would: (a) more accurately incorporate the marginal cost of load to the system, and (b) recognize the reliability value of transmission and create the energy market-equivalent of TCCs (i.e. FCTRs) for the TOs. This would allow for a more equitable allocation of capacity costs across consumers than in the current framework, which allocates capacity costs to the area where the capacity is located rather than the area that benefits from the capacity. We plan to publish more details about the anticipated allocation of costs in 2019. In addition, we plan to compare the expected performance of the C-LMP framework to the existing framework by evaluating the efficiency of prices at various levels of surplus and when there are inaccuracies in Net CONE estimates for certain localities.

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103 For an illustration of how the C-LMP framework could be used to compensate energy storage resources, see MMU presentation at the February 25 2019 ICAPWG meeting on *Alternative ELR Capacity Value Study: Methodology and Updated Results*.

E. Evaluation of Transmission Projects and Reforms to CARIS and the PPTN Process

The NYISO has an economic transmission planning process known as the Congestion Assessment and Resource Integration Study ("CARIS"). The process was intended to provide cost-of-service compensation through the NYISO tariff when a project is expected to be economic based on a tariff-defined benefit-cost analysis. However, since being established in 2008, no transmission has ever been built and received cost recovery through CARIS. The NYISO has evaluated solutions for two Public Policy Transmission Needs ("PPTN"): the Western New York PPTN and the AC Transmission PPTN.[104] The use of the PPTN assessment process to address congestion in New York highlights deficiencies in the CARIS process, which we discuss below.

We identify several deficiencies in the CARIS process, including: (i) assumptions that systematically undervalue projects, (ii) deficiencies in forecasting models, and (iii) elements that may make an economic project ineligible for funding. We recommend the following changes to address these deficiencies. We recommend changing the following assumptions that systematically undervalue projects:

- *Capacity Market Benefits* – The benefit-cost ratio that is used to identify economic projects ignores capacity market benefits, which undervalues transmission projects that make significant contributions to satisfying the NYISO's planning requirements. These benefits should be quantified using the metric discussed in Subsection C and Figure 14.[105]
- *Retirements and New Entry Assumptions* – CARIS starts with a base case from the Comprehensive Reliability Plan ("CRP"), but the CRP is developed for a different purpose that is not suited to evaluating the economics of new transmission investment. CARIS should recognize that if a new transmission project goes forward, it will likely affect the retirement and/or entry decisions of other resources.[106]

Quality forecasting is essential so we recommend the following enhancements to the models that are used to evaluate projects:

- *Gas System Modeling* – Unprecedented levels of congestion have arisen on the natural gas pipeline system since 2012 that has been the principal driver of congestion in the

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104 Each order is attached to the corresponding project solicitation letter that is posted on the NYISO website at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

105 For an example of how capacity markets can be estimated, see November 8 2018 MMU memorandum to NYISO Board of Directors on *Estimating Capacity Benefits of AC Transmission Public Policy Projects*.

106 This would require the development of a set of new entry conditions based on the costs of hypothetical wind, solar, combined cycle, and simple cycle units. In addition, this would require CARIS to measure a project's benefit based on the market value of energy and capacity in the scenario with the project rather by comparing the base case scenario to the scenario with the project. For an example of how this can be done, see our May 9, 2019 presentation to ICAPWG on *MMU Evaluation of Impact of Carbon Pricing* in which economic new entry and retirements were modeled in New York City in our evaluation of Carbon Pricing.

energy markets. Thus, efficient electricity transmission investments cannot be identified without improvements to the forecasts of future congestion on the gas pipeline system.

- *Electric System Modeling* – The NYISO uses GE MAPS to model the electrical system. However, enhancements are needed to better represent contingencies, other real-time events, and transmission outages that contribute to congestion.
- *Reserve Market Modeling* – GE MAPS has a very limited representation of operating reserves requirements, however, as more intermittent resources are added to the system, the deliverability of operating reserves will become increasingly important to estimates of the value of new transmission. Robust modeling of operating reserves would help in the selection of transmission projects. [107]
- *Local Reliability Requirements* – Most reliability requirements that drive commitments for local reliability are not represented adequately in GE MAPS. Ignoring these requirements will lead to inaccurate estimates of the benefits of transmission.[108]

There are elements of the CARIS process that could prevent an economic project from moving forward that we recommend the NYISO modify:

- *80 Percent Voting Requirement* – Before an economic project is funded, the project must garner approval from 80 percent of the beneficiaries. While such a vote may be appropriate to ensure that only projects that are clearly economic move forward, the 80 percent requirement is unreasonably high. This supermajority requirement may enable a small group of participants to block an economic investments.
- *$25 Million Threshold* – To be evaluated in CARIS, a project must cost more than $25 million, which may preclude economic projects or prevent it from being sized optimally.

These recommendations address many of the impediments in the CARIS process to investment in economic transmission projects. We recommend that the NYISO review the CARIS process to identify any additional changes that would be valuable, and make the changes necessary to ensure that the CARIS process will identify and fund economic transmission projects.[109] All the recommended changes that relate to the valuation of projects and forecasting models should also be applied to the PPTN process. Our reports evaluating proposed PPTN projects identify additional enhancements to that process.[110] In addition, we have submitted comments to the NYPSC recommending improvements to the identification of PPTNs that are more likely to result in cost-effective proposals.[111]

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107 For an example of why reserve modeling is important , see Section VIII.D.

108 For an example of how local reliability needs can be estimated, see Section VIII.D.

109 See Recommendation #2015-7 in Section XI.

110 For a list of recommendations specific to particular PPTN studies, see a) *NYISO MMU Evaluation of the Proposed Public Policy Transmission Projects in Western New York., and b) NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects.*

111 See January 22, 2019 comments of Potomac Economics in NYPSC Case 18-E-0623.

VIII. Long-Term Investment Signals

A well-functioning wholesale market establishes transparent and efficient price signals to guide generation and transmission investment and retirement decisions. This section evaluates investment signals by comparing the net revenue that generators would have received from the NYISO markets and to the capital investment costs of the generator.[112] This section:

- Evaluates net revenues and investment costs for fossil-fueled generation,
- Compares net revenues and costs of new and existing zero-emission technologies,
- Evaluates how state-subsidized resources may be treated under existing BSM rules,
- Analyzes how several of our recommended enhancements to price formation and performance incentives would affect investment incentives in New York City.

A. Net Revenues of Gas-Fired and Dual-Fuel Generators

Figure 16 compares estimated net revenues to the CONE or GFC of several types of new and existing gas-fired units from 2017 to 2020. The figure shows the incremental net revenues that would result from dual-fuel capability and the estimated number of running hours as a percent of all hours in the year.[113]

Net Revenue Summary for Gas Units

Net revenues of gas-fired resources increased from 2017 to 2018 primarily because of extreme cold weather in January, higher gas prices, and higher summer load levels. Consequently, net revenue from energy and ancillary services ("EAS") was higher in 2018 than in 2017 in all locations.

Based on forward prices for electricity and natural gas, the estimated EAS revenues in 2019-2020 were slightly higher than in 2018. However, electricity forward prices for the 2021 delivery year increased significantly while gas forward prices declined relative to 2020.[114] This is likely because the futures market pricing includes the possibility of a carbon price adder and the retirement of Indian Point.[115]

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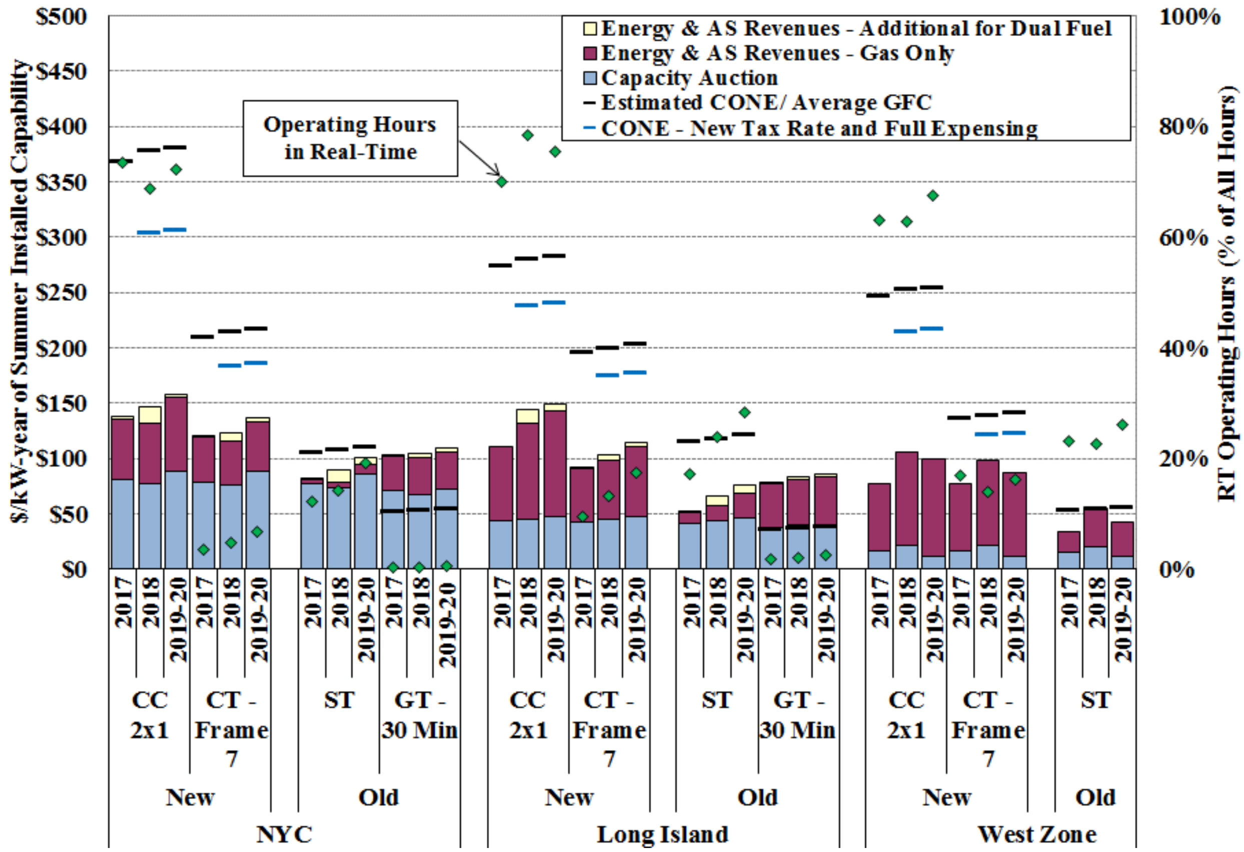
112 Net revenue is the total revenue that a generator would earn less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units.

113 Section VII.A of the Appendix provides detailed information about our assumptions as well as CONE, GFC, and net revenue results for more locations, technologies, and gas price assumptions.

114 See Figure A-102 and Figure A-103 in the Appendix for trends in gas and power forwards prices.

115 See May 2019 presentation to ICAPWG on *MMU Evaluation of Impact of Carbon Pricing* for the effects carbon pricing on different types of units in New York City.

Figure 16: Net Revenue and CONE by Location for Gas-Fired and Dual Fuel Units
2017-2020



Implications of Net Revenue Evaluation for Gas and Dual-Fuel Units

New Units – The net revenues of the hypothetical new units we evaluated were well below the estimated CONE for every case we studied for 2018. There continues to be a significant amount of surplus installed capacity which has led net revenues to be lower than the annualized CONE for all new hypothetical units in 2018. Figure 16 also shows the annualized cost of new entry using assumptions that are based on the 2017 Tax Cuts and Jobs Act ("TCJA"). The recalculated annual CONE values are 15 to 18 percent lower for new CTs and combined cycle units. In particular, the provision that allows for full expensing of eligible capital costs in the first year of operation (for projects entering prior to December 2022) could lower the CONE of a new CT by up to 14 percent.[116] The TCJA significantly improves the incentives for investment in new units as compared with existing units.

Steam Turbines – Of the existing fossil-fuel technologies we evaluated, steam turbine units are the most challenged economically. Average net revenues for steam turbines over the last three

116 However, changes in the TCJA may have countervailing effects on other factors that go into the calculation of the annual carrying charge rate, thereby reducing the impact of the new tax law on annual CONE values.

years are substantially lower than the estimated GFC on Long Island and marginally lower than the estimated GFC in New York City and the West Zone. The decision by individual steam turbine units to retire in the coming years will likely be based on whether: they are under long-term contracts, their GFCs are higher due to site-specific disadvantages, and/or they face extraordinary repair costs associated with equipment failures.

Gas Turbines – In addition to capacity revenues, the persistence of relatively high reserve prices in 2018 continue to provide strong incentives for operation of existing units. We analyze the impacts of adjusting reserve revenues for the performance of operating reserve providers (as proposed in Recommendation #2016-2) in Subsection D.

New environmental regulations may require GTs and steam turbines in New York City and Long Island to incur significant additional capital expenditures to remain in operation.

- First, the New York DEC is proposing a rule that would limit NOx and other pollutants from older GTs in New York City and Long Island.[117] Generators may comply by stopping operation during the ozone season starting May 2023 or May 2025 or by installing back-end controls (e.g., selective catalytic reduction) for limiting NOx emissions or by offsetting emissions with renewable and/or energy storage injections. Over 3.3 GW (nameplate) of GT capacity in Zones J and K is likely to be impacted by this rule.[118]
- Second, the City of New York passed an ordinance preventing steam turbine generators from burning residual oil beginning in 2022, so steam turbines will have to install facilities for burning diesel oil in order to remain dual-fueled.[119]

Dual-Fuel – Additional revenues from dual-fuel capability were considerably higher in 2018 than in 2017, particularly for combined cycle and steam turbine units. The additional revenue from dual-fuel capability resulted from the tight gas supply conditions during the January cold spell. The average returns for CC and ST units in recent years have generally been sufficient to incent dual fuel capability.[120] Dual fuel capability protects against the risk of gas curtailment under tight supply conditions and may hedge capacity revenues by reducing fuel-related outages. Thus, investors in new and existing units are likely to prefer to install and maintain dual fuel

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117 See DEC's proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, available at: http://www.dec.ny.gov/regulations/116131.html

118 See NYISO presentation at the March 19 2019 ESPWG/ TPAS meeting on *2019-2028 CRP: Peaker Scenario Assessing DEC's NOx Limits Rule for Simple Cycle and Regenerative Combustion Turbines ('Peaker Rule')*

119 See bill INT 1465-A, *Phasing out the use of residual fuel oil and fuel oil grade no.4 in boilers in in-city power plants*.

120 Dual fuel cost and inventory estimates were derived from analysis presented in the Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

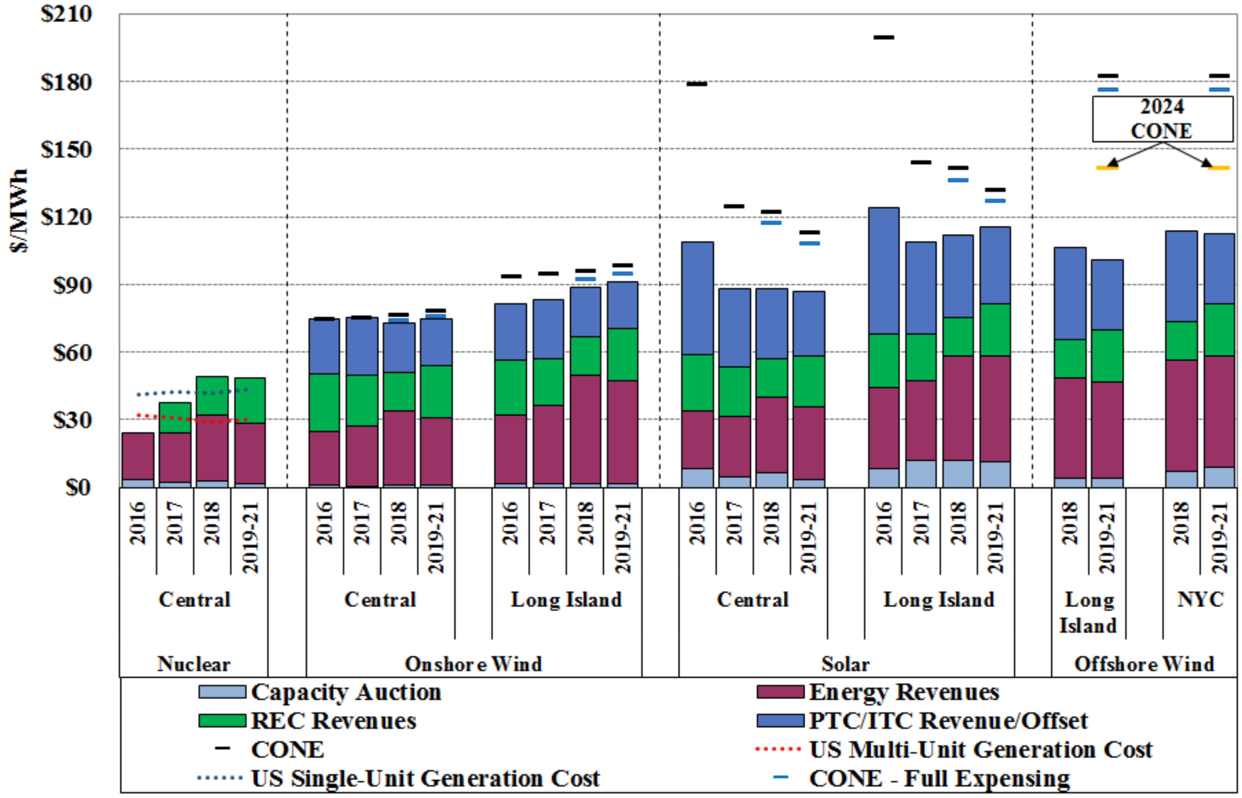
capability, particularly as they consider possible changes in market conditions over the long-term.[121]

B. Net Revenues of Nuclear and Renewable Generators

Figure 17 compares the estimated net revenues for existing nuclear units, new onshore and offshore wind units, and new utility scale solar PV plants from 2016 to 2021. For comparison, we show estimated operating costs for nuclear units and CONE estimates for the renewables.[122]

Figure 17: Net Revenues of Nuclear and Renewable Units

2016-2021



In 2018, energy markets accounted for 92 percent for nuclear units and 83 percent to 98 percent for renewable units in upstate New York. The net revenues of nuclear and renewable units from NYISO markets increased in 2018.

Both nuclear and renewable units continue to benefit from considerable state and/or federal subsidies, which accounted for 36 percent to 53 percent of the total net revenues for the upstate

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121 For example, see Analysis Group's presentation at the April 15 2019 ICAPWG/ MIWG meeting on *Fuel and Energy Security Study Assumptions and Data.*

122 See Section VII.B and VII.C of the Appendix for details about the assumptions used in this analysis.

units.[123] The ZECs and RECs are critical for operation of these units, since none of the new renewable or existing single-unit nuclear plants are economic without these subsidies.[124]

The economics of the onshore wind units has historically been better than for solar PV and offshore wind units. However, steep reductions in solar installation costs are likely to make solar PV units competitive with onshore wind units in some locations in the near future. Furthermore, the economics of individual renewable projects in New York depend on a number of additional site-specific or project-specific factors.[125] The costs of offshore wind are also projected to decline substantially in the next few years. However, new entry of offshore wind is still likely to require additional support beyond RECs, the ITC, and PTC.

C. Treatment of Public Policy Resources under the Existing BSM Rules

In recent years, the State of New York has promoted policies to encourage electricity generation from renewable sources, reduce CO_2 emissions, and improve air quality. This has led to initiatives to subsidize new clean generation and to retire relatively old, high-emitting generators. The FERC has generally sought to accommodate state policy preferences through initiatives such as Order 1000 and the granting of renewable exemptions from Buyer-Side Mitigation ("BSM") rules. However, the FERC has also sought to reconcile state policies with its mandate to ensure that wholesale electricity markets produce just and reasonable rates by approving rules that govern the entry and exit of resources.[126]

The BSM rules are the principal means by which New York state policy objectives are balanced with ensuring just and reasonable wholesale market outcomes. It is likely these will continue to evolve as the Commission seeks to accommodate changes in state policy priorities. New York has most recently promoted three types of generation: (a) zero-CO_2 emitting generators, (b) renewable generators, and (c) energy storage resources.

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123 For more detail on the federal subsidies such as PTCs and ITCs for renewable, see Appendix Section VII.C.

124 Nuclear operating and decommissioning costs are highly plant-specific, and the GFCs of the nuclear plants in New York may differ significantly from the US average operating costs. Hence, the difference between the net revenues and GFCs may be smaller than implied by Figure 17, and as a result, the nuclear plants in upstate New York (particularly single-unit) may be less economic if the generation costs do not decline in the coming years. For instance, nuclear units located in New York may be subject to higher labor costs and property taxes. Publicly available estimates for property taxes range from $2 to $3 per MWh.

125 Such factors include differences in returns required by investors, resource potential at individual sites, curtailment risk, REC prices/ procurement targets, and future cost reductions. The contracts for RECs are fixed and could be up to 20 years long. In addition, the benefits to renewable units from federal incentives are less volatile than the NYISO-market revenues. Therefore, the overall risk profile of the revenues of renewable units in New York is very different from that of a merchant generator.

126 See FERC Order No. 1000 in Docket No. RM10-23-000 on *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.* See October 9, 2015 FERC Order in Docket No. EL15-64-000 directing NYISO to file rules that would exempt a narrowly defined set of renewable resources.

To accommodate the State's objective of reducing CO_2 emissions within the framework of the wholesale market, the NYISO is moving forward with its Carbon Pricing Proposal. If implemented, this would make ZEC-recipients more economic at wholesale prices while ensuring that all generators that contribute to lower CO_2 emissions are compensated in a non-discriminatory manner. Carbon pricing would also facilitate the entry of new renewable generation, since many renewable generators would become economic at wholesale prices. Even though some renewable generators will not be economic with carbon pricing, the NYISO will likely have some form of renewable exemption from the BSM rules.

Energy storage resources are favored by State policy-makers because they are non-emitting and very flexible, which helps integrate intermittent renewable generation. While the NYISO is pursuing several market enhancements that would make energy storage resources more economic (e.g., a Zone J operating reserve requirement and Carbon Pricing), it is unclear when energy storage resources will become competitive without subsidies. Nonetheless, the current BSM rules provide a viable pathway for these resources to be exempt from mitigation, which is known as the Part A Test. The remainder of this subsection discusses the Part A Test and how it may accommodate the State's energy storage goals for New York City without the resources being mitigated.

The Part A Test is designed to allow for new entry of subsidized resources as long as it does not create artificial surpluses that cause capacity prices to be suppressed substantially below competitive levels. Specifically, a new generator will receive an exemption as long as it does not cause capacity prices to fall below 75 percent of the annualized net cost of entry of a new peaking unit. Hence, new subsidized generators can enter and sell capacity as long as the surplus capacity margin remains relatively moderate (less than 6 percent). Consequently, state policies to subsidize some resources are less likely to be mitigated if paired with policies to retire some existing resources.

The following figure examines the effects of policies to subsidize or retire resources from 2019 to 2030 to determine whether the BSM rules are likely to be an impediment to State policy initiatives in New York City. The following policies are likely to impact the capacity surplus in New York City through 2030:

- Installation of nearly 1.2 GW of battery storage and 800 MW of offshore wind interconnected in New York City through 2030.[127]

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[127] Our assumption for offshore wind in New York City (800 MW ICAP or 304 MW UCAP) is based on the assumed level of entry in the GE-MAPS simulations for the *Analysis of Carbon Charge* study presented to IPPTF. See CES Builds assumptions included in the December 12th, 2018 meeting materials.

Our assumption for entry of ESRs (1.2 GW of ICAP or 0.86 GW of UCAP) in New York City is based on the deployment scenario shown in Energy Storage Roadmap. See slides 12 and 13 of May 2018 presentation by Acelerex on *NYSERDA/ DPS Energy Storage Study Results*, Appendix K of *New York State Energy*

- NOx-emission limitations that will affect ICAP 1.65 GW (Summer DMNC) of older in-city peaking units. However, local reliability criteria may require continued operation of up to 660 MW of these units.
- The AC Public Policy Transmission Projects, which are expected to reduce the New York City LCR. These projects are currently expected to be in service by Summer 2024.
- Retirement of the Indian Point nuclear plant (in 2020 and 2021) in accordance with an agreement with the State, which is likely to increase the New York City LCR.

The bottom panel of Figure 18 shows the quantities and timing of public policy-driven entry of ESRs and offshore wind and retirement older peaking units not needed for reliability in New York City through 2030 in UCAP terms. Peakers that could be retired without creating local reliability issues are labeled "Peaker Rule Retirements." It also shows the UCAP from peaking units that are needed for reliability but could be retired if the new ESRs were to locate where Con Ed identified energy and capacity deficiencies (see "GTs Replaced by ESRs").[128]

The top panel of the figure shows the projected UCAP level in New York City for each year through 2030.[129] It also shows the projected UCAP level if new ESRs enter at locations that do not solve any of the local reliability needs associated with retirement of peaking plants. The figure also shows the Part A threshold, which represents the UCAP level below which new entrants would be exempted from BSM under the Part A test criteria.[130]

In the summer of 2019, the amount of UCAP is expected to exceed the Part A test threshold by 130 MW. In the scenario shown in Figure 18, the Part A test threshold is expected to rise significantly in 2021 because the Indian Point retirement is expected to increase the Zone J LCR and then drop in 2024 because the AC Transmission Public Policy Projects will likely reduce the LCR. The Part A test threshold will increase slowly from 2024 to 2030. The total amount of UCAP is expected to rise slowly through 2022 because of new energy storage additions, to fall sharply in 2023 because of the retirement of older peaking units, and then rise from 2023 to 2030 because of new energy storage and offshore wind additions.

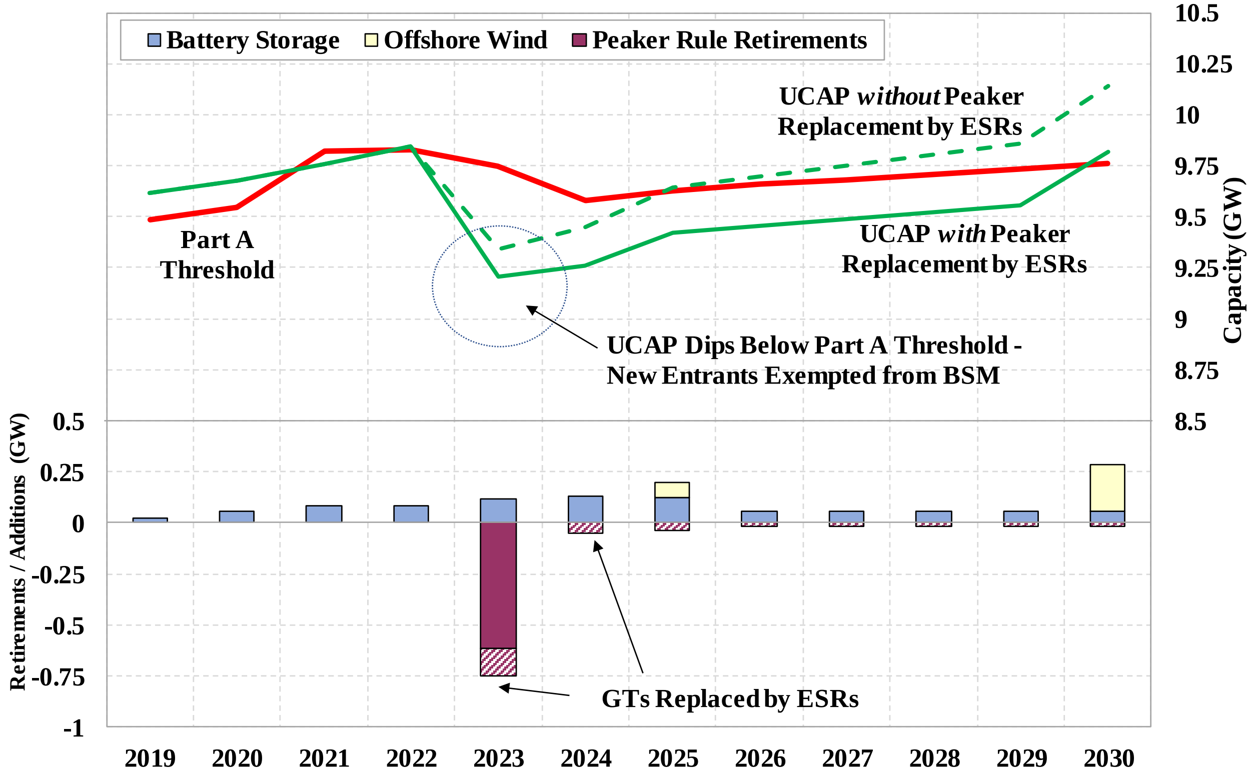
Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap), filed on June 21, 2018 in Case 18-E-0130.

128 See March 19th, 2019 presentation at ESPWG meeting by Con Edison *CRP: Peaker Scenario Assessing NOX Limits (Draft) Ruling for Simple Cycle and Regenerative Combustion Turbines*.

129 This analysis assumes no new entry in addition to the state-sponsored resources.

130 Consistent with the NYISO's ICAP Manual, we assumed a capacity value of 38 percent for offshore wind installations. Our assumed capacity value of ESRs (45 to 100 percent under 1 GW of installations and 37.5 to 100 percent over 1 GW of installations) is a function of the resource's duration and ESR penetration level, and is based on the information presented by the NYISO (slide 33) in its April 24, 2019 presentation to the Management Committee on *DER Energy and Capacity Market Design*.

Figure 18: Part A Threshold versus New York City UCAP with Public Policy Resources
2019-2030



In the scenario shown above:

- Energy storage resources that enter in 2019 and 2020 will not be exempt from mitigation.[131] However, they will not be mitigated if they are installed behind the meter, which would reduce the load forecast by an amount similar to the UCAP value of the resources.
- Starting in 2021, energy storage resources are likely to be exempt under the Part A test, and this would continue for most energy storage resources added in 2022.
- In 2023, a large number of retirements of peaking units would likely allow all energy storage resources to be exempt from mitigation.

The figure shows total UCAP under two sets of assumptions. The dashed green line assumes that 660 MW of peaking units must be kept for local reliability, which would lead energy storage resources added after 2026 to be mitigated. However, the solid green line shows that if new energy storage resources are placed at locations that contribute to satisfying the local reliability needs, it will allow an additional 400 MW (Summer DMNC) of older peaking units to be retired

131 Note, the Part A test is integrated in the Class Year process, which may take 2-3 years to complete, so projects that are capable of entering in 2019 or 2020 may not be able to sell capacity because of the slow pace of the Class Year process. For this reason, we have recommended changes to the BSM rules to allow certain projects to be tested outside the Class Year process. See Recommendation #2018-4 in Section XI.

from 2023 to 2030. Under the second scenario, the new energy storage would pass the Part A test in each year until 2030.

While the scenario above is based on a realistic set of assumptions, actual outcomes could be different for many reasons including unexpected retirements or new entry. However, the scenario illustrates a very important point. It shows that new state-subsidized resources can avoid mitigation as long as existing resources retire in sufficient quantities to maintain a surplus capacity level less than approximately 600 MW in New York City.

D. Impacts of Energy & Ancillary Services Pricing Enhancements on Net Revenue

Section XI.B of the report discusses several recommendations that are aimed at enhancing the efficiency of pricing and performance incentives in the real time markets. These recommended market reforms would also increase the financial returns to resources with attributes that are valuable to the power system such as low operating costs, reliability, availability, and flexibility. By rewarding valuable attributes efficiently, the market provides better incentives for suppliers to make cost-effective investments in new and existing resources. In this subsection, we estimate the impacts of several recommendations on the capacity prices and long-term investment incentives for several new and existing technologies.

In an efficient market, higher energy and ancillary services net revenues reduce the "missing money" that is needed to attract sufficient investment to satisfy planning reliability criteria. In recent years, the capacity demand curve has been set based on the missing money for a new Frame unit.[132] Hence, market enhancements that efficiently move net revenues to the energy and ancillary services markets lead to reductions in the capacity demand curves. We make several recommendations in this report that would shift revenues from the capacity market to the energy and ancillary services markets, thereby increasing the financial returns for resources that perform flexibly and reliably, while reducing the financial returns to poor-performing resources.

Figure 19 shows the incremental impact of each of the following recommendations on the change in net revenues of the Frame unit under the long-term equilibrium conditions:[133, 134]

- 2017-1: Model local reserve requirements in New York City load pockets.
- 2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.

132 The "missing money" refers to the revenues over and above those earned from selling energy and ancillary services that are needed to provide market incentives for maintaining sufficient capacity margins to satisfy planning reliability criteria such as the "one-day-in-ten-year" reliability standard.

133 See Section VII.D in the Appendix for details about the assumptions used in this analysis.

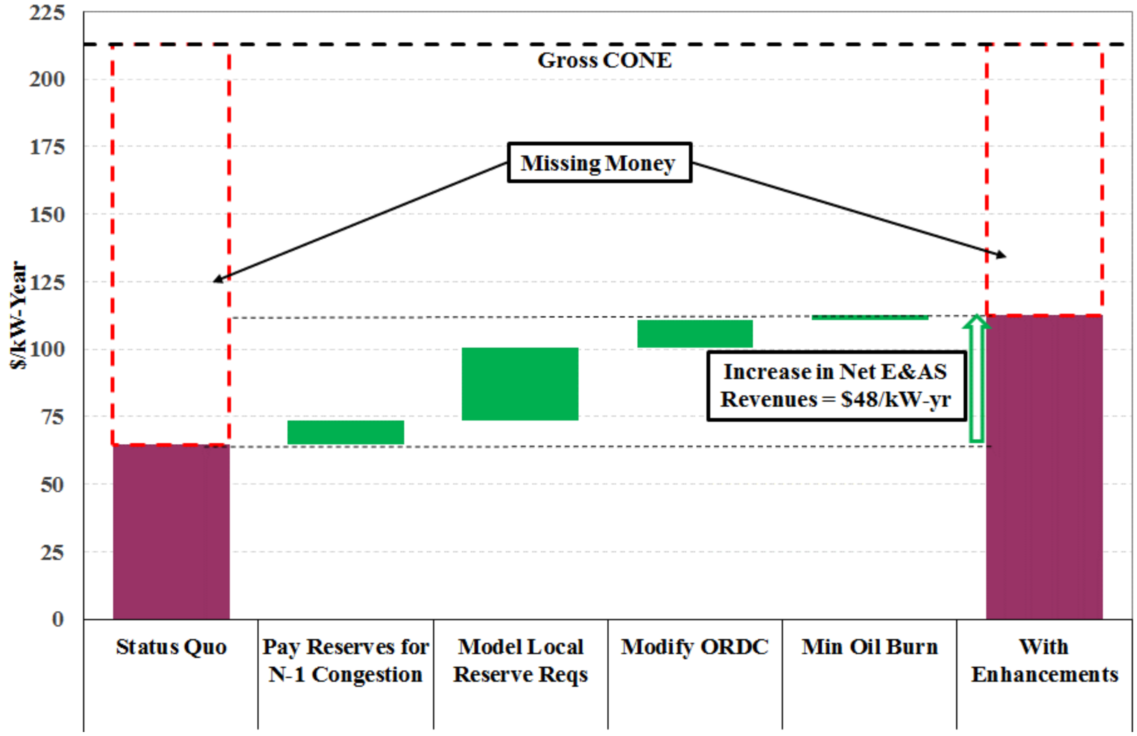
134 See Section XI for more details regarding these recommendations.

- 2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.
- 2016-2: Consider means to allow reserve market compensation to reflect actual and/or expected performance.
- Model incentive payments to the units having the capability of instantaneously switching over from gas to oil fuel supply.

The figure also shows the total increase in the Frame unit's net revenues, which would result in an equivalent decrease in the Net CONE that is used for determining the ICAP Demand Curve.

Figure 19: Impact of Pricing Enhancements on Net Revenues of NYC Demand Curve Unit

At Level of Excess Conditions

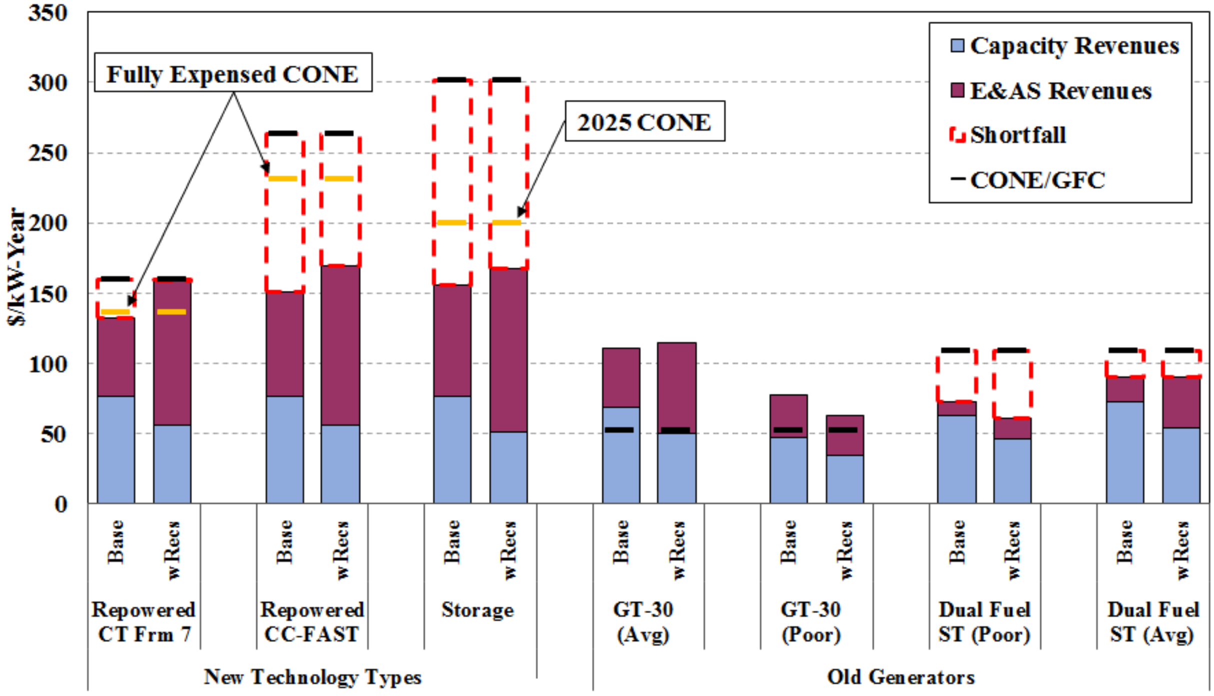


Our simulation results indicate that the E&AS revenues of a new Frame 7 unit would increase by $48 per kW-year (74 percent) if the above recommendations were implemented. Consequently, the Net CONE for the ICAP demand curve and the capacity payments to all resources would decline by 35 percent. Of the recommendations that we considered for this analysis, modeling local reserve requirements in New York City load pockets (i.e. 2017-1) had the largest impact and accounted for 57 percent increase in the E&AS revenues for the demand curve unit. Overall net revenues to a new Frame 7 unit would not change, but the recommendations would shift a large portion from the capacity market to the E&AS markets.

Figure 20 summarizes the estimated impact of recommended enhancements on energy and capacity revenues compared to the corresponding CONE/GFC for resources in NYC. The

"Base" category shows the estimated net revenues that would be received by each type of unit under the current market rules if the NYC margin was at the 2018 level, while the "wRecs" category shows our estimates if the above recommendations were adopted.

Figure 20: Net Revenue Impact from Enhancements in New York City
2018 Conditions



The recommended enhancements would increase net revenues to other new flexible technologies:

- The net revenues of a Frame 7 unit would increase to a level that could allow profitable repowering of some existing units,
- A fast-start combined cycle unit with 10-minute start capability would receive 54 percent more E&AS net revenue, while
- A flexible energy storage unit would receive 48 percent more E&AS revenue.

For new flexible technologies, the increase in energy and reserve revenues would outweigh the decrease in capacity revenues, so their overall net revenues would increase.

In contrast, the economics of older existing generators with less flexible and reliable characteristics would become less attractive. For average-performing steam turbines, overall net revenues would fall by an estimated 9 percent primarily because of the reduced capacity demand curve. The change in overall net revenues of 30-minute GTs is likely to be minimal. However, the net revenues to poor-performing 30-minute GTs and steam turbines would fall by more than 20 percent because of the reduced capacity demand curve and reduced E&AS net revenues.

For older GT-30 units, reserve revenues would drop if units were compensated in accordance with their performance as proposed in Recommendation 2016-2. GTs that perform worse than average would see a larger drop, with the margin between revenues and costs decreasing substantially. The high operating costs and lack of flexibility of steam turbines limits their ability to capture additional energy revenues from the enhancements. Consequently, the drop in their capacity revenues outweighs any increase in energy and reserve market revenues, resulting in increased economic pressure on these units to retire.

In the future, high levels of renewable penetration are expected to reduce energy prices while requiring increased procurement of ancillary services, so the recommended enhancements are likely to have larger effects on investment incentives after additional renewables are added to the grid.

IX. 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 the shortage and incent suppliers to help maintain reliability. In addition, the operation of system is critical because it can have large effects on wholesale market outcomes and costs.

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

- Market Operations during the 2017/18 Cold Spell
- Market Performance under Shortage Conditions
- Efficiency of Gas Turbine Commitments
- Performance of Operating Reserve Providers
- Operations of Non-Optimized PAR-Controlled Lines
- Market-to-Market Operations with PJM
- Drivers of Transient Real-Time Price Volatility
- Supplemental Commitment & Out of Merit Dispatch 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 XI provides a comprehensive list of our recommendations.

A. Market Operations during the 2017/18 Cold Spell

The capacity market is designed to ensure sufficient installed capacity to maintain reliability during severe summer conditions, but the NYISO does not have a market mechanism specifically designed to ensure generators have sufficient fuel to maintain reliability during severe winter conditions. Instead, the NYISO relies on the day-ahead and real-time markets to provide incentives for generators to line-up their fuel supplies necessary to be available when needed.

We evaluate the performance of the market in scheduling resources to maintain reliability during the severe cold spell from December 28, 2017 to January 8, 2018.[135] Of the capacity we estimate would have been economic to burn oil during this period in Eastern New York, only 39 percent actually burned oil. To the extent that oil-capable units were not burning oil, it was because of:

- Long-term outages of equipment for burning oil (20 percent);
- Outages and deratings not specific to oil-burning equipment (15 percent);
- Inventory-limited units (13 percent);
- Emission-limited units (11 percent); and
- Units burning natural gas (24 percent) of which one-quarter was to manage emission limitations.

Some have advocated for market mechanisms that are specifically designed to procure fuel-secure capacity during the winter, but a wide variety of reasons account for why more generation was not burning fuel oil during the Cold Snap. One reason is that the NYISO currently has significantly more fuel-secure capacity than needed to satisfy the needs of the system during peak winter conditions (which is evident from the fact that some equipment for burning oil is on long-term outage and could be brought back in-service in the future). However, it is unclear whether the NYISO will continue to have surplus fuel-secure capacity after the retirements of the Indian Point units and a large number of downstate peaking resources. The NYISO is conducting a study to evaluate resource adequacy as fuel-secure generation retires in the coming years.[136]

B. 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 energy and ancillary services needs. 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 the reflects the resources' performance. In this subsection, we evaluate the operation of the market and resulting prices in the real-time market when the system is under the following three types of shortage conditions:

- *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.

135 See Section V.A in the Appendix for this analysis in greater detail.

136 See "Fuel and Energy Security Study Scope, Method, and Inputs" by Analysis Group at ICAPWG/MIWG meeting on February 25, 2019.

- *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.
- *Reliability demand response deployments* – When the NYISO anticipates a reliability or transmission security need, it can deploy demand response resources for a minimum of four hours, typically at a cost of $500 per MWh.

Operating Reserve and Regulation Shortages

Regulation shortages were the most frequent, occurring in 12 percent of intervals in 2018 (up from 9 percent in 2017). The market is designed to "go short" of a small amount of regulation when the price rises to $25/MWh, freeing up additional capacity to provide energy. The small shortages happened more frequently in 2018 because the opportunity costs to provide regulation increased as a result of generally higher energy prices.

The most frequent reserve shortages were of NYCA 30-minute reserves, occurring in 0.4 percent of intervals in 2018, up modestly from 2017 because of higher load levels and more summer peaking conditions. All other reserves shortages occurred in less than 0.05 percent of intervals in 2018. Shortages of regulation, eastern 10-minute reserves, and NYCA 30-minute reserves collectively increased average LBMPs in Eastern New York by 9 to 11 percent in 2018.[137] Therefore, prices during ancillary services shortages have a significant impact on investment signals, shifting incentives toward generation with flexible operating characteristics.

In this report, we identify two enhancements that would improve scheduling efficiency and ensure that the real-time market provides appropriate price signals during shortage conditions. First, the NYISO does not always schedule operating reserves efficiently when the reserve needs of a local area can be satisfied by reducing imports to the area (rather than holding reserves on units inside the area). For example, 10-minute reserves are held in Eastern New York to ensure that a large contingency in Eastern New York will not cause a sudden overload of the Central-East Interface. This need could also be met by reducing flows over the Central-East interface before the contingency (thereby "holding reserves on the interface").

Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves to hold inside:[138]

- Eastern New York given flows over the Central-East Interface;
- Southeast New York given flows over the UPNY-SENY interface;
- NYCA given imports across the HVDC connection with Quebec; and

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137 See Section V.G in the Appendix for this analysis.

138 See Recommendation #2015-16 in Section XI.

- New York City load pockets (if the NYISO also implements Recommendation #2017-1) considering unused import capability into the pocket.

Second, the operating reserve demand curves in New York are substantially lower than the reliability value of holding the reserves. Efficient reserve demand curves should reflect the probability of losing load times the value of lost load ("VOLL") as reserves levels drop. The demand curves for reserves in New York reflect an implied VOLL that is much lower than most reasonable estimates.

Additionally, the NYISO curves are relatively low considering recent market design changes in neighboring markets. Since first implementing shortage pricing in 2003, the NYISO has generally benefited from significant net imports during reserve shortages. However, ISO New England and PJM both implemented Pay For Performance ("PFP") rules in mid-2018, which provide incentives similar to extreme shortage pricing.

- In ISO-NE, the Performance Payment Rate levels will rise from an initial rate of $2,000 per MWh to $5,455 in 2024.[139] These payments are in addition to the shortage pricing, which starts at $1,000 per MWh, resulting in total incremental compensation during reserve shortages ranging from $3,000 to $8,000 per MWh.
- In PJM, an initial Performance Rate was set to be between $2,000 and $3,000 per MWh in addition to real-time shortage pricing levels of $350 to $850 per MWh. The rate is also expected to rise in subsequent years.[140]

Consequently, the incentives to import power to New York under tight conditions have changed dramatically, which will reduce the available supply to New York. In the first-ever PFP event on September 3, 2018, the NYISO and ISO-NE experienced shortages of 30-minute reserves.[141] On the ISO-NE side, energy prices plus PFP incentives ranged from $3,000 to $4,700/MWh, while on the NYISO side, energy prices rarely exceeded $200/MWh. As a result, the primary NY-NE interface was fully utilized flowing 1.6 GW to ISO-NE. The weak market incentives on the NYISO side led to scheduling outcomes that had to be overridden manually by the NYISO operators, including: (a) committing gas turbines out-of-merit, (b) making emergency purchases from Ontario when responding to an emergency energy purchase request from ISO-NE; and (c) curtailing several export transactions to PJM for system security.

139 See ISO New England Tariff Section III.13.7.2.

140 The initial rate = Net CONE * Balancing Ratio (the share of capacity resources that perform during shortage events) divided by expected Performance Assessment Hours. PJM is proposing to modify its hour counts. See presentation by Patrick Bruno to the Markets Implementation Committee, April 4, 2018.

141 During this PFP event in ISO-NE. its system capacity deficiency occurred from 15:40 to 18:15, resulting primarily from under-forecast (~2.5 GW) and forced generation loss (~1.6 GW). See Section V.G in the Appendix for more details of this evaluation.

These out-of-market actions were necessary even though the interface between Ontario and the NYISO had more than 1 GW of available transfer capability during this event. If the NYISO reserve demand curves provided stronger market incentives, these out-of-market actions by NYISO may not have been necessary.

The operating reserve demand curves in New York are too low considering the willingness of NYISO operators to engage in out-of-market actions to procure more costly resources during reserve shortages. Hence, we recommend that the NYISO increase its operating reserve demand curves to levels that will schedule resources appropriately so that out-of-market actions are not necessary to maintain reliability during tight operating conditions. To ensure these levels are reasonable, the NYISO should also consider the value of lost load and the likelihood that various operating reserve shortage levels could result in load shedding. This recommendation includes establishing multiple steps for each operating reserve demand curve so that clearing prices rise efficiently with the severity of the shortage.[142]

Transmission Shortages

During transmission shortages, when power flows exceed the transmission limit, the market should set efficient prices that reflect the severity of shortage. Previous State of the Market Reports have shown a poor relationship between the severity of transmission shortages and real-time prices. They reported that small shortages tended to produce high congestion shadow prices while large shortages tended to produce small shadow prices. This was because transmission shortages were resolved by "relaxing" the limit of a constraint—that is, automatically raising the limit of the constraint to a level that could be resolved by the market software.[143]

This report shows that the relationship between price and severity has greatly improved following changes to transmission shortage pricing in June 2017.[144,145] In 2018, only 7 percent of all transmission shortages were resolved using constraint relaxation, down from over 50 percent before the software changes. The reduced use of constraint relaxation has resulted in congestion prices that are more transparent and predictable for market participants.

Although the reduced frequency of constraint relaxation has led to more efficient and transparent congestion prices, it can also increase incentives to exercise market power by over-generating

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142 See Recommendation #2017-2 in Section XI.

143 See Section V.F in the Appendix of our 2017 State of the Market report for more information.

144 The latest revision of the transmission shortage pricing rules in June 2017 includes: a) modifying the second step of the GTDC from $2,350 to $1,175/MWh; and b) applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM").

145 See Figure A-82 in the Appendix for this analysis.

upstream of a transmission constraint to benefit from extremely low LBMPs. For example, if a generator with a day-ahead schedule is the only unit available to reduce output to relieve a transmission constraint following a transmission outage, the generator can lower its offer and be paid excessively to reduce output (by buying back its day-ahead energy at a very low or negative price). Constraint relaxation generally lowered these payments. To address this, we recommend changes to the market power mitigation measures for uneconomic over-production.[146]

Despite the improved transmission shortage pricing, constraint shadow prices often did not reflect the severity of transmission shortages in 2018 for two reasons. First, a default CRM ("Constraint Reliability Margin") value of 20 MW is used for most facilities regardless of their actual physical limits. The CRM is designed to provide a margin to account for differences between the modeled flows and actual flows and to reduce the likelihood that a transmission constraint violation results in an actual overload. The sizes of such differences are usually correlated with the rating of the facility, so the NYISO sometimes uses a higher CRM for high voltage facilities with higher ratings. However, until late-2018, the NYISO's tariff did not allow the use of a CRM between 0 MW and 20 MW, so the NYISO was forced to use unnecessarily large CRM values for smaller low-voltage facilities, which led to excessive congestion on the transmission corridor from Northern to Central New York.[147] In December 2018, this problem was addressed when the tariff was modified to allow NYISO more flexibility in setting CRM values.

Second, the GTDC has a 5-MW step and a 15-MW step for a total of 20 MW where redispatch costs are limited. This ensures that as modeled flows use more of the CRM, the real-time market will place an increasing value on relieving the constraint. However, the GTDC is always 20-MW long, which is overly conservative for a large facility with a 50-MW CRM and excessively slack for a small facility with a 10-MW CRM. We analyzed the size of each modeled constraint violation compared to the CRM used for the facility.[148] We found that the GTDC is excessively slack for some facilities and overly conservative for others. Hence, we continue to recommend that the NYISO replace the current GTDC with a set of constraint-specific GTDCs that can vary according to the size of the CRM and the importance, severity, and/or duration of a transmission shortage. This will ensure a logical relationship between shadow prices and the severity of transmission constraints.[149,150]

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146 See Recommendation #2017-3 in Section XI.

147 For example, a 10-MW reduction in flows across a Browns Falls-Taylorville 115 kV line can reduce overall transfers from Northern New York to Central New York by 100 MW.

148 See Section V.H in the Appendix for a more detailed description.

149 Recommendation #2015-17 in Section XI.

150 In addition, our February 12, 2018 comments in Docket EL18-33-000 discussed that CRMs are sometimes inflated because of so-called "offline gas turbine price-setting" whereby offline gas turbines are treated as

Reliability Demand Response Deployments

The NYISO provides demand resources with two programs that compensate them for providing additional flexibility to the energy market. These programs include the Emergency Demand Response Program (EDRP) and the ICAP/SCR program. Resources enrolled in these programs typically earn the higher of $500/MWh or the real-time LBMP when called upon. Given the high costs associated with the programs, it would only be efficient to call upon these resources when all of the cheaper generation has been dispatched. However, the use of demand resources is complicated by scheduling lead times and other inflexibilities. First, the NYISO must determine how much demand response to activate when there is still considerable uncertainty about the needs of the system. Second, the demand response may not be needed for the entire activation period. Hence, there may be substantial surplus capacity during portions of the event. Therefore, it is important to set real-time prices that properly reflect the costs of maintaining reliability when reliability demand response resources are deployed.

In 2018, the NYISO activated demand response on three days, July 2, August 28 and 29, all for New York City operating reserve needs.[151] The NYISO activated 480 to 495 MW of EDRP/SCR during each event.[152] Our evaluation finds that, in retrospect, the demand response was needed to prevent a capacity deficiency on August 28 and 29, but it was not needed on July 2 because actual load was far below forecast (by roughly 2 GW) due to pop-up showers. Although the NYISO deployments prevented capacity deficiencies in New York City on August 28 and 29, this reserve need is not explicitly modeled in the market software.[153] Consequently, prices in New York City did not reflect the cost of activating demand response to maintain adequate reserves.

To manage the New York City reserve requirements in 2018, out-of-market commitment and dispatch occurred frequently, leading to over $30 million of BPCG uplift in New York City in 2018. We have recommended the NYISO model local reserve requirements in New York City load pockets, which should provide more transparent and efficient price signals.[154] An effort is currently underway for the NYISO to implement 10-minute and 30-minute reserve requirements

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able to respond to dispatch instructions when they actually cannot do so, leading to large differences between modeled flows and actual flows for some facilities (e.g., the Dunwoodie-ShoreRd 345kV line from upstate to Long Island). We recommended eliminating offline gas turbine price-setting in conjunction with the implementation of constraint-specific GTDCs in that filing.

151 Peak load ranged from roughly 31.3 GW on July 2 to 31.9 GW on August 29.

152 In addition, the NYISO SREed 1.6 GW (Danskammer 4, Bowline 1, and Oswego 5) for July 2 and 0.8 GW (Oswego 6) for August 29 for forecasted NYCA capacity needs.

153 The operators need to maintain enough 30-minute reserves in New York City to satisfy the N-1-1 thermal requirement for New York City.

154 See Recommendation #2017-1 in Section XI.

for the New York City Zone in mid-2019, which we support.[155] However, sub-zone reserve requirements are not being included in the 2019 implementation.

Additionally, most utilities also activated their own demand response programs during the three NYISO deployment events, adding 375 to 390 MW of demand response to each event. However, the amount of utility demand response is not considered in the current scarcity pricing rules, so even though the additional utility demand response deployments helped avoid a NYCA capacity deficiency for an hour on August 28, 30-minute reserves were priced only at an average of $88/MWh.[156] Moreover, various amounts of utility demand response were activated on nine other days when the NYISO did not call EDRP/SCR, but prices did not reflect the cost of these actions. It would be beneficial for the NYISO to work with TOs to evaluate the feasibility of including utility demand response deployments in the scarcity pricing rules.

C. Efficiency of Gas Turbine Commitments

We evaluate the efficiency of gas turbine commitment in the real-time market, which is important because over-commitment results in depressed real-time prices and higher uplift costs, while under-commitment leads to unnecessary price spikes. Gas turbines are usually started during tight operating conditions when it is particularly important to set efficient real-time prices that reward available generators that have flexible operating characteristics. Incentives for good performance also improve the resource mix in the long run by shifting net revenues from the capacity market to the energy market.

We found that 51 percent of the capacity committed by the real-time market model in 2018 was clearly economic over the initial commitment period (one hour for GTs), consistent with recent years.[157] This, however, likely understates the share of GT commitments that are efficient because the efficient commitment of a gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer.

Nonetheless, there were many commitments in 2018 when the total cost of starting gas turbines exceeded the LBMP by a wide margin (>25 percent). There are two primary reasons:

- The divergence between RTC and RTD may lead an economic RTC-committed GT to be uneconomic in RTD.[158]

155 See "Establishing Zone J Operating Reserves" by Ashley Ferrer at MC meeting on March 27, 2019

156 See Figure A-84 in the Appendix.

157 See Figure A-74 in the Appendix for details of this analysis.

158 See Section IV.D in the Appendix for analysis of divergence between RTC and RTD.

- The current fast-start price-setting rules do not usually reflect the start-up costs of the gas turbine in the price-setting logic.[159]

The NYISO has proposed to include the start-up and other commitment costs of fast-start units in fast-start pricing, and the Commission recently approved these changes. These will lead real-time prices to better reflect system conditions and better performance incentives for flexible resources when fast-start units are deployed. [160]

D. Performance of Operating Reserve Providers

The wholesale market should provide efficient incentives for resources to help maintain reliability by compensating resources consistent with the value they provide. Efficient incentives encourage participation by demand response and investment in flexible resources in areas where they are most valuable. Over the coming decade, performance incentives will become even more critical as the entry of intermittent resources will require more complementary flexible resources.

This section analyzes the performance of gas turbines in responding to start-up instructions in the real-time market, evaluates how the availability of and expected performance of operating reserve providers affects the costs of congestion management in New York City, and discusses how the compensation of these resources is affected by their performance.

Performance of Gas Turbines in Responding to Start-up Instructions

Figure 21 summarizes the performance of GTs in responding to start-up instructions resulting from economic commitment by the RTC model (not including self-schedules). The figure reports the average performance for GTs that received at least one start instruction in 2018. Units that were not started in-merit by RTC in 2018 are shown in "Not Started."[161]

Although gas turbines exhibited a wide range of performance in responding to start-up instructions in recent years, GT performance improved noticeably in 2018. For the same set of units that were started economically by RTC at least once in every year from 2016 to 2018, [162]

- *10-minute units*: 85 percent of units had an average response of 70 percent or better in 2018, up from 68 percent in 2016 and 65 percent in 2017. While the average response of all units was 82 percent in 2018, up from 66 percent in 2016 and 58 percent in 2017.

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159 See in Docket EL18-33-000, comments of Potomac Economics, dated February 12 and March 14, 2018.

160 See April 18, 2019 Commission order in Docket EL18-33-000.

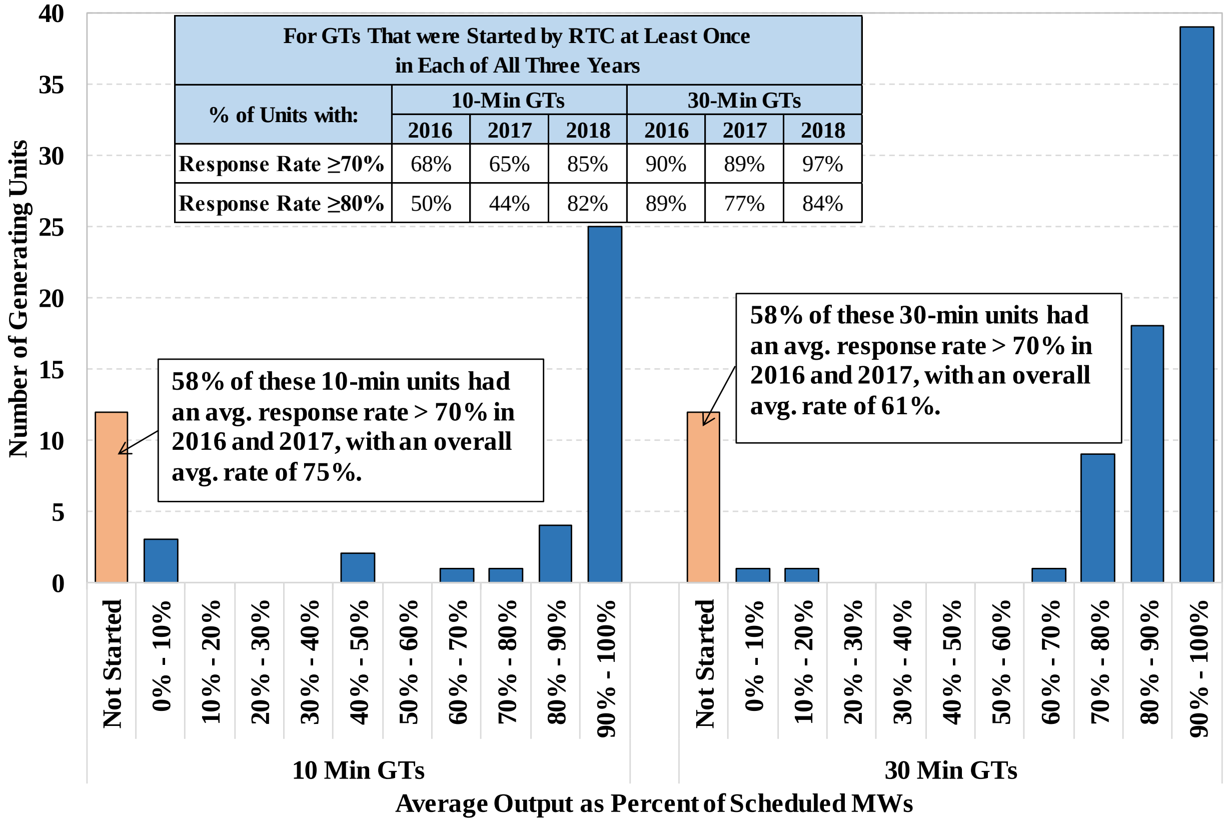
161 See Section V.C in the Appendix for a description of the figure.

162 A total of 31 gas turbines were not evaluated in 2018, including: a) 7 gas turbines that were on ICAP Ineligible Forced Outage ("IIFO"); and b) 24 gas turbines that were never started economically by RTC in 2018. We only evaluate RTC start-ups because the available data does not allow us to reliably evaluate the performance of gas turbines during other types of start-ups.

- *30-minute units*: 97 percent of units had an average response of 70 percent or better in 2018, up from 90 percent in 2016 and 89 percent in 2017. While the average response of all units was 87 percent in 2018, up from 80 percent in both 2016 and 2017.

Many of the units with relatively poor performance in 2016 and 2017 were never started by RTC in 2018, contributing to the improvement in overall performance in 2018.

Figure 21: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts, 2018



Units that perform poorly when started tend to have higher EFORds, which reduces their ability to sell capacity.[163] However, the EFORd calculation does not accurately reflect the start-up performance of fast-start units.[164] Additionally, gas turbines lose their energy revenues when they fail to start, but there is no mechanism for discounting operating reserve revenues for gas turbines that do not perform well. Hence, some gas turbines that almost never perform when called will still earn most of their net revenue from the sale of operating reserves.[165] Because

163 See Appendix Section VI.C for information about the distribution of EFORds for individual gas turbines.

164 For example, if a 10-minute GT is producing 0 MW after 10 minutes and takes 25 minutes to start, it will be treated as having a successful service hour.

165 See Appendix Section VII.A for more information about the net revenue of gas turbines.

operating reserve revenues are not sensitive to suppliers' performance, the market does not provide efficient performance incentives to reserve providers. To address this concern, we recommend that the NYISO consider ways to allow reserve revenues to reflect suppliers' performance.[166] The NYISO plans to evaluate this concern as a part of its 2019 Project: *More Granular Operating Reserves*.

Use of Operating Reserves to Manage New York City Congestion

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 sometimes operates a facility above LTE if post-contingency actions would be available to quickly reduce flows to LTE after a contingency.[167] Post-contingency actions include the 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 flows into load centers and reduce the congestion costs.

The value of rules that allow congestion to be managed with reserve capacity rather than actual generation dispatch becomes apparent when reserve capacity 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 2018, 73 percent (or $125 million) of real-time congestion occurred on N-1 transmission constraints that would have been loaded above LTE after a single contingency. As shown in Table 15, the additional transfer capability above LTE on New York City transmission facilities averaged from roughly 20 MW for some constraints in the 138 kV load-pockets to over 200 MW for constraints in the 345 kV system during congested hours. This helped reduce generation production costs by an estimated $15 million in New York City in 2018.[168]

166 Recommendation #2016-2 in Section XI.

167 See *NYISO Transmission and Dispatching Operations Manual*, Section 2.3.2.

168 See Appendix Section V.C for more information about this analysis.

Table 15: Modeled Limits vs Seasonal Limits for Select New York City N-1 Constraints
2018

Transmission Facility		Average Constraint Limit (MW)		
		N-1 Limit Used	Seasonal LTE	Seasonal STE
345 kV	E13th ST-W49th ST	1227	993	1568
	Farragut-Gowanus	1069	829	1301
	Gowanus-Goethals	971	737	1233
	Motthavn-Dunwodie	1074	854	1307
	Motthavn-Rainey	1038	833	1298
	W49th ST-Sprnbrk	1236	950	1540
138 kV	Vernon-Greenwd	252	234	268
	Gowanus-Greenwd	344	317	369
	Foxhills-Greenwd	310	246	375

Although these increases were largely due to the availability of operating reserve providers in New York City, they are not compensated for this service. This reduces their incentives to be available in the short term and to invest in flexible resources in the long term. In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability into New York City, making the dispatch of these units inefficient in some cases.

Hence, we recommend the NYISO evaluate ways to efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria.[169] For similar reasons, the NYISO should also consider market-based compensation for generators that support transmission security by being able to continue to operate (e.g., dual fuel units that can quickly switch from gas to oil) following the loss generation after a natural gas system contingency.

E. Operations of Non-Optimized PAR-Controlled Lines

Most transmission lines that make up the bulk power system are not controllable and, thus, must be secured by redispatching generation to maintain flows within appropriate levels. However, there are still a significant number of controllable transmission lines that source and/or sink in NYCA. This includes HVDC transmission lines, VFT-controlled lines, and PAR-controlled lines. Controllable transmission lines allow power flows to be channeled along pathways that lower the overall cost of generation necessary to satisfy demand. Hence, they have the potential to provide greater benefits than conventional AC transmission lines. Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways:

- Some controllable transmission lines are scheduled as external interfaces, which are evaluated in Section VI.C that assesses external transaction scheduling.[170]

169 Recommendation #2016-1 in Section XI.

170 This includes HVDC lines (Cross Sound Cable, Neptune Cable, the line connecting NYCA to Quebec, and the HTP Line), VFT-controlled lines (Dennison Line and Linden VFT), and the 1385 PAR-controlled line.

- "Optimized" PAR-controlled lines are normally adjusted to reduce generation redispatch costs (i.e., to minimize production costs) in the day-ahead and real-time markets.
- "Non-optimized" PAR-controlled lines are scheduled according to operating procedures that are not primarily based on reducing production costs, which are evaluated below.

Table 16 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2018. This is done for seven PAR-controlled lines between New York and neighboring areas and two between New York City and Long Island.[171] This 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.

The Lake Success and Valley Stream PARs control flows over the 901 and 903 lines, which are operated under the ConEd-LIPA wheeling agreement to wheel up to 290 MW from upstate to Long Island and then on to New York City. In the day-ahead market in 2018, power was scheduled in the efficient direction in only 6 to 10 percent of hours. Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.

Table 16: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[172, 173]

2018

	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					-30	$7.09	47%	-$2
New England to NYCA								
Sand Bar	-75	-$18.17	95%	$12	-1.6	-$17.04	55%	$0.5
PJM to NYCA								
Waldwick	-61	$1.39	45%	$0.3	-8	$1.34	50%	-$2
Ramapo	256	$2.30	73%	$8	157	$2.35	59%	$7
Goethals	120	$4.26	81%	$5	86	$0.68	53%	-$1
Long Island to NYC								
Lake Success	135	-$5.77	10%	-$8	-3	-$6.34	48%	-$0.3
Valley Stream	69	-$10.97	6%	-$8	0.04	-$10.64	46%	-$0.1

171 Two PAR-controlled lines between New York City and PJM, the B and C lines, are not included in this assessment for 2018 because they were out of service for almost the entire year.

172 This table reports the estimated production cost savings from the actual use of these transmission lines. They are *not* the production cost savings that could have been realized by scheduling the lines efficiently.

173 As discussed further in Section V.E of the Appendix, this metric tends to under-estimate the production cost savings from lines that flow from low-priced to high-priced regions. However, it tends to over-estimate the

The transfers across the 901 and 903 lines:

- *Increased* day-ahead production costs by $16 million in 2018 because prices on Long Island were typically higher than those in New York City where the lines connect.[174]
- Restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect and at the nearby Astoria Annex. Restrictions on these New York City generators sometimes increases price in a much wider area (e.g., during an eastern reserve shortage or a TSA event with severe congestion into Southeast New York).
- Increase the consumption of gas from the Iroquois pipeline, which often trades at a significant premium over gas consumed from the Transco pipeline.
- Drive-up generation output from older less-fuel-efficient gas turbines and steam units without Selective Catalytic Reduction capability, leading to increased emissions of CO_2 and NOx pollution in non-attainment areas.

There are significant opportunities to improve the operation of the 901 and 903 lines under the ConEd-LIPA wheeling agreement. It would be highly beneficial to modify this contract or find other ways under the current contract to operate the lines more efficiently.[175] Although this should benefit both parties in aggregate, it may financially harm one party. Hence, it would be reasonable to create a financial settlement mechanism that would ensure that both parties benefit from the changes.[176] We recommend the NYISO work with the parties to this contract to explore changes that would allow the lines to be used more efficiently.[177]

The scheduling efficiency over the Goethals, Farragut, and Waldwick lines[178] improved generally following the expiration of the ConEd-PSEG wheeling agreement in May 2017 (notwithstanding the outage of the Farragut lines since January 2018).[179] Although the operation

production cost increases from lines that flow from high-priced to low-priced regions. Nonetheless, it is a useful indicator of the relative scheduling efficiency of individual lines.

174 These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica pocket in New York City, an area that is frequently export-constrained.

175 See NYISO OATT Section 18, Table 1 A - Long Term Transmission Wheeling Agreements, Contract #9 governs the operation of the lines between New York City and Long Island.

176 The proposed financial right would compensate ConEd for congestion management consistent with the revenue adequacy principles underlying nodal pricing, so the financial right holder would receive congestion revenues like other wholesale market transactions from the congestion revenue fund and no uplift charges would be necessary. The proposed financial right is described in Section VI.G of the Appendix.

177 See Recommendation #2012-8 in Section XI.

178 The Goethals line is known as the “A” line, the Farragut lines are known as the “B & C” lines, and the Waldwick lines are known as the “J & K lines.”

179 These lines were operated under the ConEd-PSEG wheeling agreement to wheel up to 1000 MW from Hudson Valley to PJM and then on to New York City prior to May 1, 2017. Afterwards, these lines have

of these PARs has improved since May 2017, operations over the Waldwick lines were much less active, resulting in less efficient scheduling than over the Goethals line. Consequently, the Waldwick lines accounted for a $2 million net *increase* in production costs in 2018, while the Goethals line accounted for a $4 million net *reduction* in production costs. The next sub-section examines the operation of these lines under M2M coordination with PJM.

F. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources when it is less costly to do so.[180,181] Figure 22 evaluates operations of these PARs under M2M with PJM in 2018 during periods of congestion between New York and PJM.[182]

Overall, the PAR operations under M2M with PJM have provided benefit to the NYISO in managing congestion on coordinated transmission flow gates. We have observed instances of efficient M2M coordination as PARs were moved in the direction to reduce overall congestion costs in a relatively timely manner. Balancing congestion revenue surpluses frequently resulted from this operation on the Central-East interface (including an estimated $11 million of revenue surpluses for 2017 and 2018. See Section III.E in the Appendix), indicating that the process reduced production costs and congestion in New York.

Nonetheless, there were instances when PAR adjustments were likely available and that would have reduced congestion, but no adjustments were made. During all of the 30-minute periods in 2018 when the congestion differential between PJM and NYISO exceeded $10 per MWh across these PAR-controlled lines (which averaged less than five times per day), PAR taps were taken in only 17 percent of these periods. Overall, each PAR was adjusted just 1 to 5 times per day on average, which is well below their operational limits of 20 taps per day and 400 taps per month.

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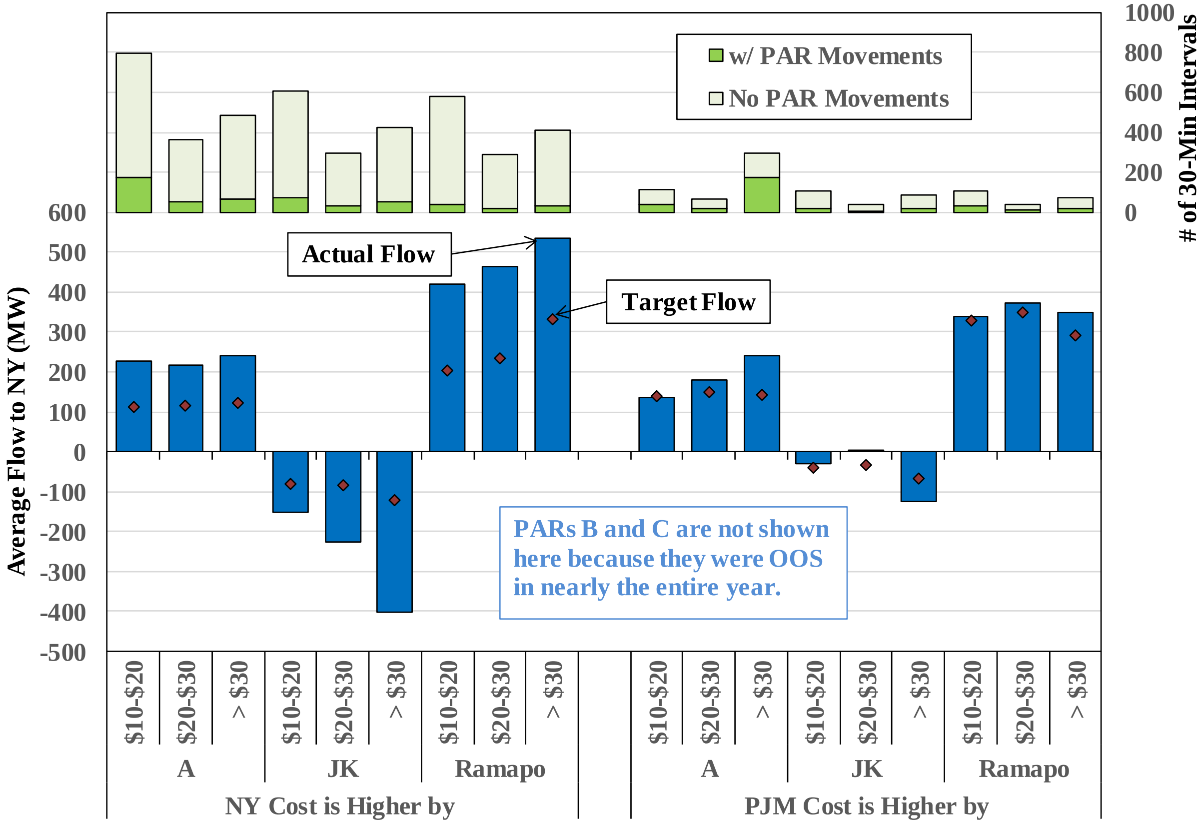
been operated: (a) to flow a share of the external transactions scheduled over the primary interface between New York and PJM); and (b) to manage real-time congestion under M2M with PJM.

180 The terms of M2M coordination are in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

181 Ramapo PARs have been used in the M2M process since its inception in January 2013, while Goethals, Farragut, and Waldwick PARs (i.e., A, B&C, and J&K PARs) were added in May 2017 following the expiration of the ConEd-PSEG Wheel agreement.

182 See Section V.D in the Appendix for a detailed description of the figure.

Figure 22: NY-NJ PAR Operation Under M2M with PJM
During Congested Periods, 2018



Although actual flows across these PAR-controlled lines typically exceeded their M2M targets towards NYISO during these periods, flows were generally well below their seasonal limits (over 500 MW for each line). In some cases, PAR adjustments were not taken because of: [183]

- Difficulty predicting the effects of PAR movements under uncertain conditions;
- Adjustment would push actual flows or post-contingent flows close to the limit;
- Adjustment was not necessary to maintain flows above the M2M target;
- The transient nature of congestion; and
- Mechanical failures (e.g., stuck PARs).

These results highlight potential opportunities for increased utilization of the M2M PARs. Our evaluation of factors causing divergences between RTC and RTD also identifies the operation of these PARs as a net contributor to price divergence.[184] This is partly because RTC has no information related to expected tap changes. Consequently, RTC may schedule CTS imports to relieve congestion, but operators may already be taking tap adjustments in response to the

183 However, we lack information necessary to determine how often these factors prevented PAR adjustments.

184 See Appendix Section IV.D for a more detailed discussion on factors causing RTC and RTD divergence.

congestion, leading the scheduled imports to be uneconomic. The contribution pf these lines to price divergence between RTC and RTD fell from 2017 to 2018 because the B and C lines were out of service throughout 2018. However, this illustrates why forecasting PAR tap adjustments would also help reduce divergences between RTC and RTD. Unfortunately, NYISO operators do not have a congestion or production cost forecasting model that can be used to determine the efficient schedule for these M2M PARs, so it will be difficult to optimize the PAR operation without a model to forecast the impacts of PAR tap adjustments in real time.

G. Transient Real-Time Price Volatility

Volatile prices can be an efficient signal of the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants, so it is important to identify the causes of volatility. In this subsection, we evaluate 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 2018. The effects of transmission constraints are more localized, while the power-balance and reserve constraints affect prices throughout NYCA.

Although transient price spikes occurred in roughly 4 percent of all intervals in 2018, these intervals were important because they accounted for a disproportionately large share of the overall market costs. In general, unnecessary 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, and reduced uplift costs.

Drivers of Transient Real-Time Price Volatility

Table 17 summarizes the most significant factors that contributed to real-time price volatility in 2018. It shows their contributions to spikes in the power-balance constraint and the most volatile transmission constraints. Contributions are also shown for: (a) external interchange and other resources scheduled by RTC; (b) flow changes from un-modeled factors, such as loop flows; and (c) load and wind forecast error as well as generator derates.[185] For each group of transmission constraints, the most significant categories and sub-categories are highlighted in purple and green, respectively.

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185 See Section V.F in the Appendix for more details about the evaluation and additional factors that contribute to transient real-time price spikes.

Table 17: Drivers of Transient Real-Time Price Volatility
2018

	Power Balance	West Zone 230kV Lines	Central East	Dunwoodie - Shore Rd 345kV	Intra-LI Lines	NYC Load Pockets	North to Central
Average Transfer Limit	**n/a**	**586**	**2423**	**816**	**280**	**310**	**321**
Number of Price Spikes	**663**	**989**	**223**	**304**	**653**	**3501**	**556**
Average Constraint Shadow Price	**$256**	**$729**	**$368**	**$310**	**$483**	**$559**	**$520**
Source of Increased Constraint Cost:	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
Scheduled By RTC	**62%**	**10%**	**52%**	**60%**	**57%**	**36%**	**11%**
External Interchange	30%	10%	18%	41%	14%	18%	11%
RTC Shutdown Resource	23%	0%	24%	16%	29%	9%	0%
Self Scheduled Shutdown/Dispatch	8%	0%	9%	3%	14%	9%	0%
Flow Change from Non-Modeled Factors	**7%**	**70%**	**34%**	**19%**	**29%**	**55%**	**56%**
Loop Flows & Other Non-Market	1%	50%	8%	11%	21%	27%	44%
Fixed Schedule PARs	0%	20%	25%	7%	7%	27%	11%
Redispatch for Other Constraint (OOM)	6%	0%	1%	1%	0%	0%	0%
Other Factors	**31%**	**20%**	**14%**	**21%**	**14%**	**9%**	**33%**
Load	17%	10%	7%	10%	7%	0%	11%
Generator Trip/Derate/Dragging	8%	0%	6%	11%	7%	9%	0%
Wind	7%	10%	1%	0%	0%	0%	22%

Resources scheduled by RTC (e.g., external interchange and gas turbine shut-downs) were a key driver of transient price spikes for the power-balance constraint and most transmission constraints shown in the table (except the constraints in the West Zone and from North to Central New York). RTC evaluates resources at 15-minute intervals and may shut-down large amounts of capacity or reduce imports by a large amount without considering whether resources will have sufficient ramp in each 5-minute evaluation period by RTD to satisfy the energy, reserve, and other operating requirements.

Flow changes from non-modeled factors were the primary driver of constraints across the West Zone 230kV Lines, the Central-East interface, lines in the New York City load pockets, and constraints from North to Central New York. Loop flows and other non-market factors were the primary driver for the West Zone 230 kV lines. Clockwise circulation around Lake Erie puts a large amount of non-market flows over lines in the West Zone.

Fixed-schedule PAR-controlled line flow variations (over the A, J, K, and 5018 lines) were a key driver of price spikes for the West Zone 230kV lines, the Central-East Interface, and the lines in New York City load pockets. These PARs are modeled as if they fully control pre-contingent flow across the PAR-controlled lines, which is unrealistic.[186] The PARs are not adjusted frequently in response to variations in generation, load, interchange, and other PAR adjustments.[187] Since each PAR is adjusted less than five times per day on average, the telemetered value can change significantly from one interval to the next, resulting in transitory price spikes. In addition, when the PARs are adjusted, it may cause congestion that was not anticipated because the operator does not have a model that forecasts the congestion impact of making tap adjustments.

Among other factors, variations in load forecast had significant impact on the power balance constraint, while changes in wind forecast were a key driver of constraints from North to Central New York as well. Overall, load forecast error and wind forecast error accounted for a relatively small portion of the transient prices spikes.

We also evaluated factors that made the largest contributions to price divergences between RTC and RTD in Section VI.D. The factors mentioned above that contributed most to transient price spikes were also identified as significant contributors to this price divergence. We also evaluate the effects of inconsistencies between the ramp assumptions used in RTC versus the ones used in RTD in Appendix Section IV.D.

Potential Solutions to Address Non-Modeled Factors

To reduce unnecessary price volatility from variations in loop flows and flows over PAR-controlled lines that are not modeled in the dispatch software, we recommend the NYISO: [188]

- Make additional adjustments for loop flows. The adjustment should be "biased" in the clockwise direction to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., under-forecasting is more costly than over-forecasting); and
- Reconsider its method for calculating shift factors. The current method assumes that pre-contingent PAR-controlled line flows are unaffected by generation re-dispatch and load changes, although with the exception of PARs with auto-tap changers, this is not what occurs in actual operations unless PAR tap moves are manually taken.

H. Supplemental Commitment & Out of Merit Dispatch for Reliability

Supplemental commitment occurs when a unit is not committed economically in the day-ahead market, but is needed for reliability. It primarily occurs through: (a) Day-Ahead Reliability Units ("DARU") commitment occurs at the request of transmission owners for local reliability;

186 RTD and RTC assume that the flows across these PAR-controlled lines would remain fixed at the most recent telemetered values plus an adjustment for DNI changes on the PJAC interface.

187 Section IX.F evaluates the performance of these PAR-controlled lines under M2M with PJM and shows that these tap adjustments on these PARs averaged one to five times per day.

188 See Recommendation #2014-9 in Section XI.

(b) Day-Ahead Local Reliability Rule ("LRR") commitment that takes place during the economic commitment within the day-ahead market; and (c) Supplemental Resource Evaluation ("SRE") commitment that occurs after the day-ahead market closes.

Similarly, the NYISO and local transmission owners sometimes dispatch generators out-of-merit ("OOM") in order 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 amount of supply available in real-time, while OOM dispatch increases production from capacity that is normally uneconomic and displaces output from economic capacity. Both of these actions 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.

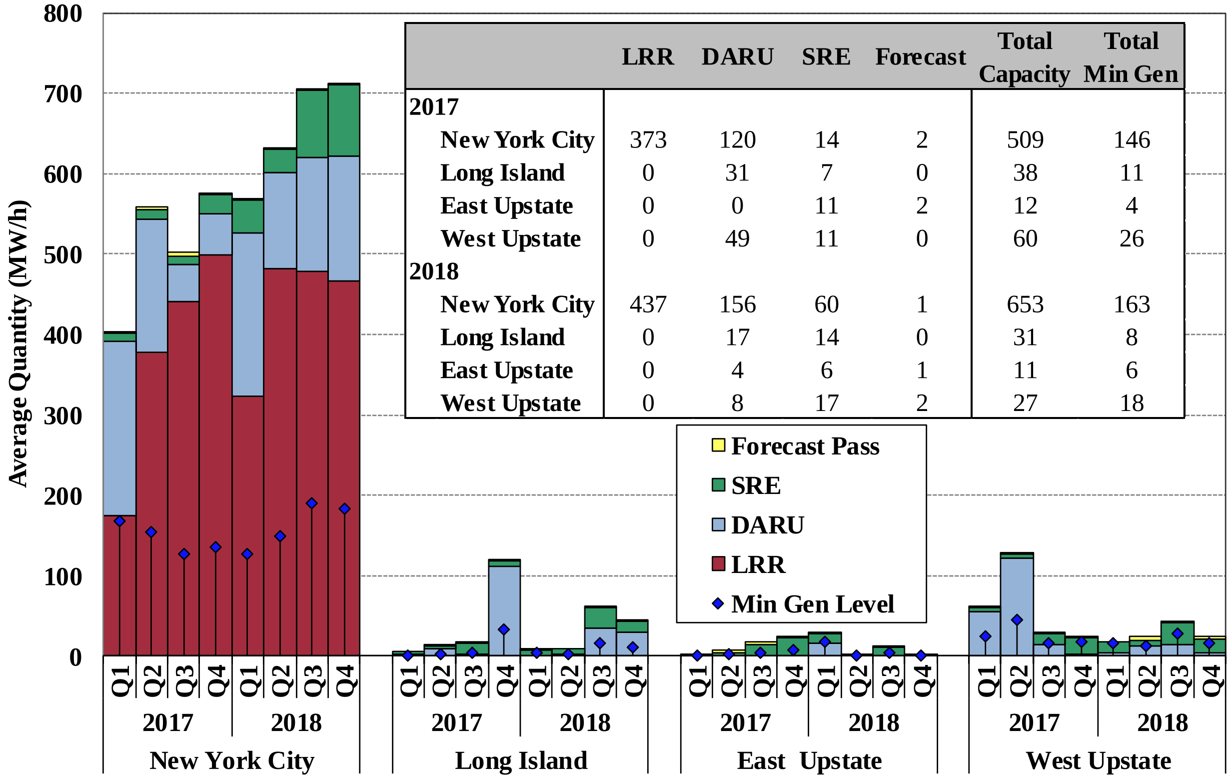
Supplemental Commitment in New York State

Figure 23 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2017 and 2018.[189]

Roughly 720 MW of capacity was committed on average for reliability in 2018, up 17 percent from 2017. The increase occurred primarily in New York City, which rose 28 percent from 2017 and accounted for 90 percent of total reliability commitment in 2018. Higher load levels and lengthy transmission outages greatly increased the need to commit generation for the N-1-1 thermal requirement in the 345 kV system, but most supplemental commitments were made to satisfy the N-1-1 requirements in the sub-regions on the 138 kV system. The supplemental commitment for the Astoria West/Queensbridge/Vernon load pocket rose in 2018 partly because of more planned generation outages of combined-cycle units in the pocket.

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

Figure 23: Supplemental Commitment for Reliability in New York
By Category and Region, 2017 – 2018



Reliability comments in other areas were relatively infrequent in 2018. In particular, DARU commitments in Western New York have fallen sharply since July 2017 following the completion of transmission upgrades that allowed the Milliken RSSA to expire.

Supplemental Commitment in New York City for N-1-1 Constraints

Reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1 criteria) in New York City. Since such units would not be economic if they were not needed for local reliability, they ordinarily do not earn enough market revenues to recoup their day-ahead as-offered costs. Hence, such units typically receive a day-ahead BPCG payment.

Although the resulting amount of compensation (i.e., revenue = cost) is reasonably efficient for the marginal commitment needed to satisfy the needs of the pocket, it does not provide efficient incentives for lower cost resources that can also provide valuable operating reserves in the pocket to be available. Moreover, it does not provide investors with efficient incentives to invest in new and existing resources that are capable of satisfying the need at a lower cost. Therefore, it would be beneficial for the NYISO to seek ways to design a reserve product that could satisfy the local N-1-1 requirements in a way that provides market-based compensation to all suppliers that provide the product in the load pocket, not just the ones with high operating costs.

To assess the market incentives that would result from modeling N-1-1 requirements in New York City, we estimated the clearing prices that would have occurred in 2018 if the NYISO were to devise a day-ahead market reserve requirement.[190] Table 18 summarizes the results of this evaluation based on market results for four locations in New York City: the 345kV network north of Staten Island, the Astoria West/Queensbridge load pocket, the Vernon location on the 138 kV network, and the Greenwood/Staten Island load pocket.

Table 18: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2018

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	**$2.01**
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	**$5.18**
Vernon	**$4.23**
Greenwood/Staten Is.	**$3.39**

Based on our analysis of operating reserve price increases that would be necessary to represent the marginal costs of satisfying N-1-1 requirements in the day-ahead market, we find such price increases would range from an average of $2.01 per MWh in most areas to as much as $5.18 per MWh in the Astoria West/Queensbridge load pocket in 2018. These price increases would be in addition to the prices of operating reserve products in Southeast New York.

We also estimated how the energy and reserve net revenues of various types of units would be affected if they were compensated for reserves in New York City load pockets at the rates shown in Table 18.[191] Based on these results, we have recommended that the NYISO model N-1-1 constraints in New York City load pockets, which should provide a more efficient market mechanism to satisfy reliability criteria at these locations.[192] The NYISO plans to have a 10-minute reserve product and a 30-minute reserve product for New York City, beginning mid-2019. We support this effort and believe it is a good step towards more efficient scheduling and pricing in New York City load pockets.[193]

190 Section V.J in the Appendix describes the methodology of our estimation.

191 See analysis in Section VIII.D.

192 See Recommendation #2017-1 in Section XI.

193 See “Establishing Zone J Operating Reserves” by Ashley Ferrer at MC meeting on March 27, 2019

Out of Merit Dispatch

Table 19 summarizes the frequency (in station-hours) of OOM actions over the past two years for four regions: (a) West Upstate, including Zones A through E; (b) East Upstate, including Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K.[194]

Table 19: Frequency of Out-of-Merit Dispatch
By Region, 2017-2018

Region	OOM Station-Hours		
	2017	2018	% Change
West Upstate	1668	875	-48%
East Upstate	1169	1643	41%
New York City	147	463	215%
Long Island	755	2310	206%
Total	**3739**	**5291**	**42%**

The quantity of OOM dispatch rose 42 percent from 2017 to 2018 due primarily to higher load levels and more frequent peaking conditions. Long Island, which saw a 206 percent increase in OOM levels from 2017, accounted for the largest share (nearly 45 percent) of OOM actions in 2018. The increase occurred primarily in the summer months as high-cost peaking resources were frequently needed out-of-market to manage congestion on the 69 kV network and voltage needs on the East End of Long Island under high load conditions. On the other hand, Western New York, which accounted for the largest share of OOM actions in 2017, saw a reduction of 48 percent in 2018. The decrease occurred partly because of transmission upgrades completed in July 2017. These allowed the Milliken RSSA to expire and reduced OOM needs. The OOM actions have been significant in the East Upstate area as several units were frequently OOMed to manage post-contingency flow on some 115 kV facilities that are currently not modeled in the day-ahead and real-time markets.

In addition, the Niagara generator was often manually instructed to shift output between the generators at the 115 kV station and the generators at the 230 kV station to secure certain 115 kV and 230 kV transmission facilities. However, these were not classified as OOM unless the NYISO adjusted the UOL or LOL of the Resource. Manual shifting has been required for more than 1,000 hours annually in recent years. The NYISO enhanced modeling of the Niagara Plant in December 2018 to recognize the congestion impact from the 115 and 230 kV locations.[195] This should help improve the efficiency of scheduling and pricing.

194 Figure A-89 in the Appendix shows our analysis on a quarterly basis and shows top two stations that had most frequent OOM dispatches in 2017 for each region.

195 See "Niagara Generation Modeling Update" by David Edelson at MIWG meeting on May 9, 2018.

Given the inefficient pricing, dispatch and uplift caused by the frequent OOM actions taken to manage congestion 69 kV facilities in Long Island, we recommend the NYISO model these transmission constraints in the day-ahead and real-time markets to allow them to be priced and managed efficiently.[196]

I. Guarantee Payment Uplift Charges

The NYISO recovers the payments it makes to certain market participants that are not recouped from LBMP and other market revenues through uplift charges. It is important to minimize uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When markets reflect reliability requirements and system conditions, uplift charges should be relatively low. The following figure shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2017 and 2018 on a quarterly basis.[197]

The figure shows that the guarantee payment uplift totaled $77 million in 2018, up 102 percent from 2017. The increase occurred in most areas and was driven primarily by:

- Increased supplemental commitments and OOM dispatch as discussed above in subsection H; and
- Higher natural gas prices, which increased the commitment costs of gas-fired units.

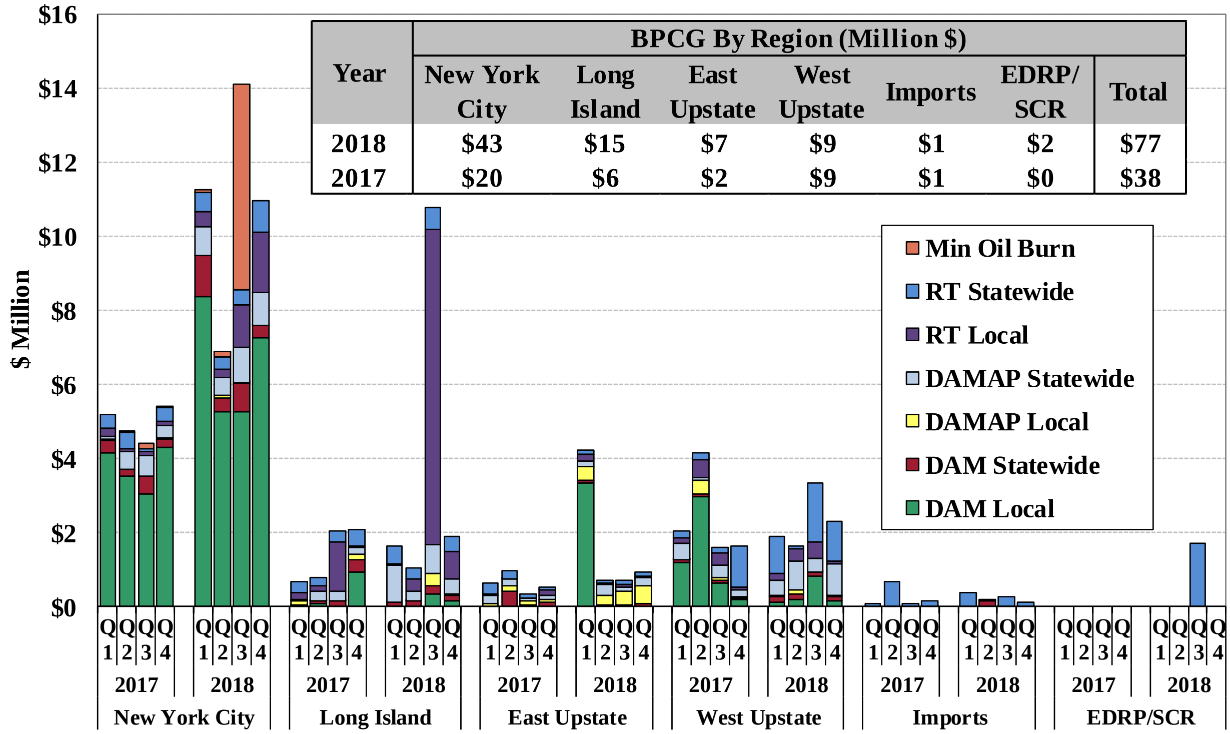
Most of the increase occurred in New York City, which accounted for $45 million (or 56 percent) of BPCG in 2018, up 119 percent from 2017. Over $26 million was paid to generators that were committed for N-1-1 local requirements. We have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals. [198]

196 See Recommendation #2014-12 in Section XI.

197 See Figure A-90: Uplift Costs from Guarantee Payments by MonthFigure A-90 and Figure A-91 in the Appendix for a more detailed description of this analysis.

198 See Recommendation #2017-1.

Figure 24: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2017 – 2018



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2018	$43	$15	$7	$9	$1	$2	$77
2017	$20	$6	$2	$9	$1	$0	$38

Long Island also saw a substantial increase in real-time local BPCG uplift. Nearly $10 million of BPCG uplift was paid to high-cost peaking resources on Long Island that were frequently OOMed to manage congestion in the 69 kV network and voltage needs on the East End of Long Island. We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets.[199] This should provide a more efficient market signals for investment that tends to help satisfy reliability criteria.[200]

199 See Recommendation #2014-12.

200 Our estimates show significant LBMP impact in the Long Island load pockets from these potential modeling improvements. See Figure A-53 in the Appendix.

X. 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 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. This section evaluates existing demand response programs.

Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, Day-Ahead Demand Response Program ("DADRP") and Demand-Side Ancillary Services Program ("DSASP"), provide a means for economic demand response resources to participate in the day-ahead market and in the ancillary services markets. The other three programs, Emergency Demand Response Program ("EDRP"), Special Case Resources ("SCR"), and Targeted Demand Response Program ("TDRP"), are reliability demand response resources that are called when the NYISO or the local Transmission Owner forecasts a shortage. Currently, 99 percent of the 1,315 MW of demand response resources registered in New York are reliability demand response resources.[201]

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,309 MW of resources participating in 2018. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. In the six months of the Summer 2018 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 5.6 percent of the UCAP requirement for New York City;
- An average of 4.2 percent of the UCAP requirement for the G-J Locality;
- An average of 1.9 percent of the UCAP requirement for Long Island; and
- An average of 3.9 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources fell by roughly 50 percent from 2010 to 2018 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011. These have improved the accuracy of baselines for some resources, reducing the amount of capacity they are qualified to sell. Business decisions to reduce or cease

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

participation have been partly driven by relatively low capacity prices in some areas in recent years and reduced revenues as a result of the enhanced auditing and baseline methodology.

Demand-Side Ancillary Services Program

This program allows demand-side resources to offer operating reserves and regulation service in the wholesale market. Currently, three DSASP resources in Upstate New York actively participate in the market, providing considerable value by reducing the cost of ancillary services in the New York market. These resources collectively provided an average of more than 100 MW of 10-minute spinning reserves in 2018, satisfying nearly 15 percent of the NYCA 10-minute spinning reserve requirement.

Day-Ahead Demand Response Program

No resources have participated in this program since 2010. Given that loads may hedge with virtual transactions similar to DADRP schedules, the value of this program is questionable.

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 2018, the NYISO activated EDRP and SCR resources on three days (i.e., July 2, August 28 and 29) in Zone J only for New York City reserve needs. Various amounts of demand response were also activated additionally by local utility on these three days. The operations and pricing efficiency are evaluated in Section IX.B of this report.

XI. RECOMMENDATIONS

Our analysis in this report indicates that the NYISO electricity markets performed well in 2018, although we recommend additional enhancements to improve market performance. Twenty-one recommendations are presented in six 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 2017 SOM Report, but Recommendations #2018-1 to #2018-4 are new in this report. The following table summarizes our current recommendations.

Number	Section	Recommendation	Current Effort	High Priority
Energy Market Enhancements - Pricing and Performance Incentives				
2018-1	V.B	Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions and develop associated mitigation measures.		
2017-1	VIII.D, IX.H	Model local reserve requirements in New York City load pockets.	✓	✓
2017-2	VIII.D, IX.B	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	✓	✓
2016-1	VIII.D, IX.D	Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.		
2016-2	VIII.D, IX.D	Consider means to allow reserve market compensation to reflect actual and/or expected performance.	✓	
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.		
2015-16	IX.B	Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.		
2015-17	IX.B	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	✓	
Energy Market Enhancements – Market Power Mitigation Measures				
2017-3	IX.B	Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.		
2017-4	III.B	Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.		
Energy Market Enhancements - Real-Time Market Operations				
2014-9	VI.D, IX.G	Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.		

Number	Section	Recommendation	Current Effort	High Priority
2012-8	IX.E	Operate PAR-controlled lines between New York City and Long Island to minimize production costs and create financial rights that compensate affected transmission owners.		
2012-13	VI.D, IX.G	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.		
Capacity Market – Market Power Mitigation Measures				
2018-2	III.C	Modify the Competitive Entry Exemption to allow contracts that are determined to be competitive and non-discriminatory.		
2018-3	III.C	Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.		
2018-4	III.C	Develop tariff provisions to perform Mitigation Exemption Tests outside the Class Year process for resources that are smaller than 2 MW.		
2013-2d	III.C	Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated.		
Capacity Market – Design Enhancements				
2013-1c	VII.D	Implement locational marginal pricing of capacity (“C-LMP”) that minimizes the cost of satisfying planning requirements.		✓
2012-1a	VII.D	Establish a dynamic locational capacity framework that reflects potential deliverability, resource adequacy, and transmission security requirements.		
2012-1c	VII.C	Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.		
Planning Process Enhancements				
2015-7	VII.E	Reform the CARIS process to better identify and fund economically efficient transmission investments.		

This section describes each recommendation, discusses the benefits that are expected to result from implementation, identifies the section of the report where the recommendation is evaluated in more detail, and indicates whether there is a current NYISO project or stakeholder initiative that is designed to address the recommendation. The criteria for designating a recommendation as “High Priority” are discussed in the next subsection. The last subsection discusses several recommendations that we considered but chose not to include this year.

A. Criteria for High Priority Designation

As the NYISO MMU, we are responsible for recommending market rule changes to improve market efficiency. In each of our annual state of the market reports, we identify a set of market rule changes that we recommend the NYISO implement or consider. In most cases, a particular recommendation provides high-level specifics, 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. We make recommendations that have the greatest potential to enhance market efficiency given our sense of the effort level that would be required. In each report, a few recommendations are identified as "High Priority" for reasons discussed below.

When evaluating whether to designate a recommendation as High Priority, we assess how much the recommended change would likely enhance market efficiency. To the extent we are able to quantify the benefits that would result from the enhancement, we do so by estimating the production cost savings and/or investment cost savings that would result because these represent the accurate measures of economic efficiency. In other cases, we quantify the magnitude of the market issue that would be addressed by the recommendation. As the MMU, we focus on economic efficiency because maximizing efficiency will minimize the costs of satisfying the system's needs over the long-term.

Other potential measures of benefits that largely capture economic transfers associated with changing prices (e.g., short-term generator revenues or consumer savings) do not measure economic efficiency. Therefore, we do not use such measures when suggesting priorities for our recommendations. However, market rule changes that reduce production costs significantly without requiring an investment in new infrastructure result in large savings relative to the market development costs (i.e., a high benefit-to-cost ratio). Such changes that would produce sustained benefits for at a number of years warrant a high priority designation.

In addition to these considerations, we often consider the feasibility and cost of implementation. Quick, low-cost, non-contentious recommendations generally warrant a higher priority because they consume a smaller portion of the NYISO's market development resources. 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

2018-1: Model in the day-ahead and real-time markets Long Island transmission constraints that are currently managed by NYISO with OOM actions and develop associated mitigation measures.

Market incentives are inadequate for investment in resources that help secure the 69kV system on Long Island partly because these facilities are not modeled in the NYISO's energy and ancillary services markets. Currently, these constraints are secured primarily through out-of-market actions, which has raised guarantee payments and is sometimes inefficient. We recognize that implementing a process to manage these constraints in the day-ahead and real-time markets would require significant effort, since it would requires additional coordination with the local Transmission Owner. [202]

Some lower-voltage transmission constraints raise local market power concerns, which are addressed with mitigation measures that limit suppliers' ability to extract inflated guarantee payments. Once these constraints are modeled and priced, the mitigation measures may need to be expanded to address the potential exercise of market power in day-ahead or real-time energy markets.

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 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, as well as incentives for new investment that can satisfy the local requirements.[203] Hence, we recommend the NYISO consider implementing local reserve requirements in the New York City load pockets.

The NYISO's assessment should consider three related issues. First, the NYISO should consider whether changes are necessary to the market power mitigation measures. Second, since the amount of reserves needed to satisfy the N-1-1 requirements in the day-ahead market depends on whether sufficient energy is scheduled to satisfy forecast load, we recommend that the NYISO consider adjusting the reserve requirement to account for any under-scheduling of energy.

Third, while most local N-1-1 requirements are driven by the potential loss of the two largest Bulk Power System elements supporting a particular load pocket, the NYISO also should consider whether local reserve requirements would be appropriate for maintaining reliability following the loss of multiple generators due to a sudden natural gas system contingency.

2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability. (Current Effort, High Priority)

Since it first implemented shortage pricing for energy and operating reserves in 2003, the NYISO has generally benefited from significant net imports during reserve shortages and other

202 See discussion in Section V.B.

203 See discussion in Section IX.H. See 2019 Project: *More Granular Operating Reserves*.

extreme scarcity conditions. However, ISO New England and PJM is phasing-in the implementation of new PFP ("Pay For Performance") rules from 2018 to 2022. PFP rules provide incentives similar to shortage pricing, whereby incremental compensation for energy and operating reserves will rise to $3,000+ per MWh during reserve shortages. Consequently, the market incentives that have encouraged generators and power marketers to bring power into New York are changing. Hence, we recommend that the NYISO evaluate the incentive effects of the PFP rules and consider modifying its operating reserve demand curves to provide efficient incentives and ensure reliability during shortage conditions. This evaluation should consider having multiple steps for each operating reserve demand curve so that:

- Clearing prices rise to levels that are efficient given the value-of-lost-load and the risk of load shedding; and
- The real-time market schedules available resources such that NYISO operators do not need to engage in out-of-market actions to maintain reliability.[204]

This recommendation is high priority because taking out-of-market actions to maintain reliability during reserve shortage conditions (because the real-time market does not schedule available resources) leads to inefficient scheduling, poor real-time performance incentives, and less efficient commitment and investment incentives. Further, we believe this has a relatively low level of complexity and should be less difficult to implement than most other recommendations.

2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.

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.[205] The NYISO should also consider market-based compensation for generators that support transmission security by continuing to operate following the loss of multiple generators due to a sudden natural gas system contingency.

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204 See discussion in Section IX.B. See 2019 Project: *Ancillary Services Shortage Pricing*.

205 See discussion in Section IX.D of this report and Section IX.C of the 2016 SOM Report. See 2020 Project Candidate: *Pricing Reserves for Congestion Management*.

2016-2: Consider means to allow reserve market compensation to reflect actual and/or expected performance. (Current Effort)

Operating reserve providers are compensated the same regardless of how they perform when deployed by the NYISO. Consequently, the market does not provide efficient performance incentives to generators that are frequently scheduled for reserves. To address this concern, we recommend the NYISO consider discounting reserve awards based on past performance. For example, a 10-MW fast start unit that starts and reaches its instructed output level 80 percent of the time could be scheduled for up to 8 MW of reserves. As part of this effort, the NYISO should consider whether changes would be warranted for any of its operating reserve requirements to account for this adjustment.[206]

2015-9: Eliminate transaction fees for CTS transactions at the PJM-NYISO border.

The efficiency benefits of the 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. 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. Hence, we recommend eliminating transaction fees and uplift charges between the PJM and NYISO.[207]

2015-16: Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.

In some cases, the reserve requirement for a local area can be met more efficiently by importing reserves (i.e., reducing flows into the area and treating the unused interface capability as reserves), rather than scheduling reserves on internal generation. The report identifies four examples where this functionality would provide significant benefits.

- Resources in Zone K are limited in satisfying operating reserve requirements for SENY, Eastern NY, and NYCA, but the amount operating reserves scheduled in Zone K could be increased in many hours. Long Island frequently imports more than one GW from upstate, allowing larger amounts of reserves on Long Island to support the requirements outside of Long Island. Converting Long Island reserves to energy in these cases would be accomplished by simply reducing imports to Long Island, thereby reducing the required generation outside of Long Island.

206 See discussion in Section IX.D. The NYISO states that it plans to address this concern as a part of the 2019 Project: *More Granular Operating Reserves*.

207 See discussion in Section VI.D. See 2020 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

- The amount of operating reserves that must be held on internal resources can be reduced when there is unused import capability into Eastern New York or into SENY. In fact, it is often less costly to reduce flows across Central East or the interface into SENY (i.e., to hold reserves on these interface) rather than hold reserves on internal units in Eastern New York.
- Imports across the HVDC connection with Quebec could be increased significantly above the level currently allowed, but this would require corresponding increases in the operating reserve requirements (to account for a larger potential contingency). Since increased imports would not always be economic, it would be important to optimize the reserve requirement with the level of imports.
- If the NYISO implements recommendation 2017-1, the amount of operating reserves that need to be held on resources in a particular load pocket could be reduced when there is unused import capability into load pocket. In many cases, it will be less costly to reduce flows into the load pocket (i.e., to hold reserves on the interface) rather than hold reserves on internal units inside the load pocket.

Hence, we recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each of these requirements.[208]

2015-17: Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages. (Current Effort)

Historically, transmission constraints that could not be resolved were "relaxed" (i.e., the limit was raised to a level that would accommodate the flow). However, this does not lead to efficient real-time prices that reflect the reliability consequences of violating the constraint. To address this pricing concern, 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 is a significant improvement, but it does not appropriately prioritize transmission constraints according to the importance of the facility, the severity of the violation, or other relevant criteria. Hence, we recommend 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.[209]

Energy Market Enhancements – Market Power Mitigation Measures

2017-3: Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.

The current market power mitigation rules impose financial penalties on a supplier that over-produces to create transmission congestion, but this happens only if the congestion leads to high

[208] See discussion in Section IX.B. See 2020 Project Candidate: *Dynamic Reserve Requirements*.

[209] See discussion in Section IX.B. See 2019 Project: *Constraint Specific Transmission Shortage Pricing*.

prices downstream of the transmission constraint. However, a supplier with a significant long position in the forward market can benefit from setting extremely low clearing prices in the spot market. So, the current market power mitigation rules should be modified to deter uneconomic over-production even when it does not result in high clearing prices downstream of the constraint.[210]

2017-4: Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold.

The automated mitigation procedure ("AMP") applies generator-specific offer caps when necessary to limit the exercise of market power in New York City. Each generator-specific offer cap is based on an estimate of the generator's marginal cost, which is known as its "reference level." Natural gas price volatility and limitations on the availability of fuel have increased the need to adjust reference levels to reflect changing market conditions. Generators can reflect changes in their fuel costs and fuel availability by submitting a "fuel cost adjustment." The current market power mitigation rules include provisions that are designed to prevent a supplier from submitting inappropriately high fuel cost adjustments to avoid mitigation by the AMP. However, the current rules are inadequate to deter a supplier from submitting inappropriately high fuel cost adjustments during some conditions. To address this deficiency, we recommend that the NYISO impose a financial sanction for economic withholding by submitting an inappropriately high fuel cost adjustment that is comparable to the financial sanction for physical withholding.[211]

Energy Market Enhancements – Real-Time Market Operations

2014-9: Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.

Variations in loop flows and flows over PAR-controlled lines were among the leading causes of real-time transient price spikes and poor convergence between RTC and RTD prices in 2018. To reduce the effects of variations in loop flows, we recommend the NYISO consider developing a mechanism for forecasting additional adjustments from the telemetered value. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude).

A significant portion of the variations in unmodeled flows result from two unrealistic assumptions in the modeling of PAR-controlled lines: (a) that the pre-contingent flows over

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210 See discussion in Section IX.B.

211 See discussion in Section III.B.

PAR-controlled lines are not influenced by generator redispatch even though generator redispatch affects PAR-controlled lines like it would any other AC circuit, and (b) that PARs are continuously adjusted in real-time to maintain flows at a desired level even though most PAR-controlled lines are adjusted in fewer than 4 percent of intervals.[212] Eliminating these unrealistic assumptions would improve the accuracy of the modeling of these PARs and reduce the frequency of transient price spikes and improve consistency between RTC and RTD.

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 2018, these lines were scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 90 and 94 percent of the time. Their operation increased production costs by an estimated $16 million, and sometimes restricted production by economic generation in New York City.[213]

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.G 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 is 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: [214]

- 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

[212] See discussion in Sections VI.D and IX.F . See 2020 Project Candidate: *Enhanced PAR Modeling*.

[213] See discussion in Section IX.E. See 2020 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

[214] See discussion in Sections VI.D and IX.G. See 2020 Project Candidate: *RTC-RTD Convergence Improvements*.

interchange adjustment. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

- 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.
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
- 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.
- 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.
- Modify ramp limits of individual units to reflect that a unit providing regulation service cannot ramp as far in a particular five-minute interval as a unit that is not providing regulation (since regulation 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 become increasingly important as the NYISO integrates more intermittent renewable generation in the coming years.

Capacity Market – Market Power Mitigation Measures

2018-2: Modify the Competitive Entry Exemption to allow contracts that are determined to be competitive and non-discriminatory.

The Competitive Entry Exemption is designed to allow a developer to obtain an exemption from buyer-side mitigation if it agrees not to accept state subsidies or enter into contracts that could serve as a conduit for subsidies. Under the current rules, developers agree not to contract with certain prohibited entities, although the tariff specifies a list of exceptions to this rule. For example, developers are generally prohibited from contracting with transmission-owning utilities, but exceptions are made for interconnection agreements.

We recommend expanding the list of exceptions to include power supply agreements that can be determined to be open to new and old resources, competitive, and non-discriminatory. For example, if the utility runs an auction to buy power that is competitive and open to all suppliers, the NYISO could determine that the resulting power supply agreement will not serve as a conduit for subsidies to the seller. This change would allow generators and utilities to enter into competitive contracts to hedge risk while still fulfilling the objective of the buyer-side mitigation measures.[215]

2018-3: Consider modifying the Part A test to exempt a New York City unit if the forecasted price of the G-J Locality is higher than its Part A test threshold.

The Part A test of BSM evaluations is designed to exempt a project whose capacity is needed to satisfy the local capacity planning requirement where the project would locate. Thus, a New York City generator would be exempt if it was needed to satisfy the LCR for New York City. However, a New York City generator would not be exempt if it was needed to satisfy the LCR for the G-J Locality. Given the large resource mix changes that are expected in the coming years, we recommend modifying the Part A test to test a New York City generator against the larger G-J Locality requirement in addition to the New York City requirement.[216]

2018-4: Develop tariff provisions to perform Mitigation Exemption Tests outside the Class Year process for resources that are smaller than 2 MW.

The BSM measures are currently applied within the Class Year process, which was designed for conventional generators that take years to develop and bring into commercial operation. However, new projects do not need to go through the Class Year process to obtain injection rights if they are smaller than 2 MW. Moreover, battery storage projects and other short lead-time projects are capable of entering in just a few months, so we recommend the NYISO develop a set of procedures and requisite tariff changes for applying the BSM measures outside the Class Year process, perhaps on a quarterly cycle.[217]

2013-2d: Enhance Buyer-Side Mitigation Forecast Assumptions.

The set of generators that is assumed to be in service for the purposes of the exemption test is important because the more capacity that is assumed to be in service, the lower the forecasted capacity revenues of the Examined Facility, thereby increasing the likelihood of mitigating the Facility even if it is economic. Likewise, the timing of new entry is also important, since the economic value of a project may improve after future retirements and transmission additions. We recommend the NYISO modify the BSM assumptions to allow the forecasted prices and project interconnection costs to be reasonably consistent with expectations.[218]

215 See discussion in Section III.C. See 2020 Project Candidate: *Competitive Entry Exemption Non-Qualifying Contract Rule Review*.

216 See discussion in Section III.C.

217 See discussion in Section III.C. See 2020 Project Candidate: *BSM Evaluation for Small Resources Outside of the Class Year*.

218 See list of recommended assumptions in Section III.C. See 2020 Project Candidates: *Enhanced BSM Forecasts Assumptions* and *Enhanced Mitigation Study Period*.

Capacity Market – Design Enhancements

2013-1c: Implement locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements. (High Priority)

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The demand curve reset process sets the capacity demand curve for each locality relative to the IRM/LCR without fully considering whether this results in a consistent relationship between the clearing prices of capacity and the marginal reliability value of capacity in each Locality. Although the changes in the LCR implemented in 2018 are an improvement, the resulting capacity procurements and prices are not fully efficient, which raises the overall cost of satisfying the capacity needs. 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 implement 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.[219] 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 proposal 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.

2012-1a: Establish a dynamic locational capacity framework that reflects potential deliverability, resource adequacy, and transmission security requirements.

The existing rules for creating New Capacity Zones will not lead to the timely creation of a new capacity zones in the future when: (a) additional capacity is needed to meet resource adequacy criteria in areas that are not currently zones, (b) when the NYISO's Class Year Deliverability Test is inefficiently restricting new entry and capacity imports, or (c) when the net cost of new entry varies by a wide margin within a large capacity region that will predictably lead to deliverability and resource adequacy issues.

Establishing a dynamic locational framework by pre-defining interfaces and corresponding zones based on system planning requirements would ensure that locational capacity prices would immediately adjust to reflect changes in market conditions, including the retirement of key units in the state's aging fleet regardless of whether the retirement is anticipated or unexpected. This

219 See discussion in Section VII.D. See 2020 Project Candidate: *Locational Marginal Pricing of Capacity*.

will, in turn, allow investors to be more confident that the reliability needs will be fully priced and facilitate timely market-based investment.

Under the current rules, when a New Capacity Zone is created, supplier-side and buyer-side market power mitigation rules are automatically applied to the new zone. However, if a comprehensive set of interfaces (and corresponding zones) were pre-defined based on system planning requirements, it would not necessarily be appropriate to apply mitigation rules to every zone. Therefore, we recommend de-coupling the application of market power mitigation from the process of creating a new zone.[220]

2012-1c: Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.

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 benefits that are comparable to capacity from resources in constrained areas. Accordingly, transmission should be compensated for the resource adequacy 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.[221]

Enhance Planning Processes

2015-7: Reform the CARIS process to better identify and fund economically efficient transmission investments.

The current economic transmission planning process does not accurately estimate the economic benefits of proposed projects. We identify in this report several key assumptions that lead transmission projects to be systematically under-valued. Additionally, the current requirement for 80 percent of the beneficiaries to vote in favor of a proposed project is likely to prevent economic projects from being funded. We recommend that the NYISO review the CARIS process to identify any additional changes that would be valuable, and make the changes

220 See Section VII.F of the 2017 State of the Market for the NYISO. See 2020 Project Candidate: *Dynamic Creation of Zones*.

221 See discussion in Section VII.C. See 2020 Project Candidate: *Capacity Transfer Rights for Internal Transmission Upgrades*.

necessary to ensure that the CARIS process will identify and fund economic transmission projects.[222]

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 2017 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2017 State of the Market Report.

#2017-1 – The NYISO has proposed to begin modeling a 30-minute operating reserve requirement in New York City of 1,000 MW. This requirement will initially use a reserve demand curve of $25/MWh. This is a significant step towards meeting the objectives of Recommendation #2017-1, which is to satisfy the N-1-1 reliability requirements of New York City, although it will be important to set up operating reserve requirements for sub-load pockets as well.

#2016-1 – The NYISO has proposed to begin modeling a 10-minute operating reserve requirement in New York City of 500 MW. This requirement will use a reserve demand curve of $25/MWh. This is a step towards meeting the objectives of Recommendation #2016-1, which would explicitly model the use of 10-minute reserve units to manage N-1 transmission congestion into New York City and into the sub-load pockets.

#2014-12 – The NYISO has implemented a process for identifying 115 kV facilities in upstate New York that should be incorporated and managed in the day-ahead and real-time markets. This has substantially addressed the concerns underlying Recommendation #2014-12.

#2013-11 – The NYISO has proposed to revise its tariff in accordance with the requirements of Order 841. This will enable resources registered as Energy Storage Resources to submit total production limitations across multiple hours in the day-ahead market. This will provide flexibility to schedule these resources in the most valuable hours while respecting the overall

222 See discussion in Section VII.D.

production limitations of the resources. Recommendation #2013-11 also sought to allow fossil fuel generators with fuel constraints and other energy limitations to have the ability to reflect these in a manner similar to Energy Storage Resources. However, the NYISO found that the combination of these energy limitations with integer constraints (e.g., start-up, minimum generation levels, and minimum run times) in the day-ahead market would significantly increase the complexity of the design and solution times. Thus, we have withdrawn the recommendation in this report.

Other Recommendations Not Included on the List for 2018

This subsection describes several recommendations from previous reports that were not resolved but that are not included in this report. First, the 2015 State of the Market Report recommended expanding the buyer-side mitigation measures to address additional actions such as subsidizing uneconomic existing capacity to suppress capacity prices. We have recommended that the Commission adopt a mitigation measure to address such conduct and this issue is pending before the Commission in a complaint proceeding.[223] After the Commission orders on this proposal, we will reassess the adequacy of the buyer-side mitigation measures.

Second, the state of the market reports from 2002 to 2012 recommended that the NYISO adopt virtual trading at the sub-zonal level. Since its introduction in November 2001, virtual trading at the zone level has consistently helped improve day-ahead scheduling decisions when systematic differences in modeling and/or behavior between the day-ahead and real-time markets would have otherwise led to under/over-commitment in the day-ahead market.[224] Virtual trading at the subzone level would likely improve the efficiency of day-ahead commitments, fuel procurement decisions, and consistency between day-ahead and real-time prices in areas with persistent differences. Although we continue to see significant persistent differences between day-ahead and real-time prices and associated scheduling inefficiencies that could be ameliorated by virtual trading at the subzone level, we removed the recommendation from the list after the 2012 report because the proposal did not make significant progress in the stakeholder process in the previous eleven years.

Third, Recommendation #2014-10 in the 2016 State of the Market Report proposed that the NYISO include start-up costs in the fast-start pricing logic when fast-start units are in their initial minimum run time. The Commission has since issued a 206 filing that preliminarily found the NYISO pricing to be unjust and unreasonable partly because it did not incorporate start-up costs

223 See Commission Docket EL13-62.

224 Beginning in 2002, each state of the market report has discussed the effects of virtual trading and inconsistencies between day-ahead and real-time market outcomes that would be addressed by virtual trading at the sub-zone level.

in the fast-start pricing logic. The NYISO has responded with a proposal that would remedy this deficiency, which we support.[225] After the Commission orders on this proposal, we will reassess whether additional changes to the fast-start pricing logic are warranted.

Fourth, Recommendation #2014-13 in the 2017 State of the Market Report proposed that the NYISO work with generators in NOx bubbles to determine whether they have other available options for NOx RACT compliance that would result in more efficient operation of their steam turbine units. However, the New York Department of Environmental Conservation recently issued a proposed rule that would no longer allow firms to average the emissions of their gas turbine units with steam turbine units in the same portfolio starting in 2023.[226] If the proposal is adopted, it will obviate the need for this recommendation.

Fifth, Recommendation #2015-8 in the 2017 State of the Market Report proposed that the NYISO: (a) continue efforts to develop a probabilistic Locality Exchange Factor for use when a generator in an import-constrained capacity zone exports to a neighboring control area that is interconnected to the NYCA capacity region and (b) develop more appropriate pricing of capacity imports from neighboring control areas that are interconnected to multiple capacity regions across a single interface (e.g., PJM and ISO-NE). This recommendation has been dropped because the underlying objectives would be achieved by Recommendation #2013-1c, which is to develop locational marginal pricing of capacity based on the marginal reliability value of capacity at each location.

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[225] See Commission Docket EL18-33-000.

[226] See DEC's proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, available at: http://www.dec.ny.gov/regulations/116131.html

Analytic Appendix

2018 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 2018 in the following areas:

- Wholesale market prices;
- Fuel prices, generation by fuel type, and load levels;
- Fuel usage under tight gas supply conditions;
- 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 summarizes the energy prices and other wholesale market costs by showing the all-in price for electricity, which reflects the total costs of serving load from the NYISO markets. The all-in price includes the costs of energy, uplift, capacity, ancillary services, and NYISO cost of operations. The all-in price is calculated for various locations in New York State because 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 2011 to 2018 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.

Natural gas prices are based on the following gas indices (plus a transportation charge of $0.20 per MMBtu): (a) the Dominion North index for the West Zone and areas in Central New York; (b) the Iroquois Waddington index for North Zone; (c) the Iroquois Zone 2 index for the Capital Zone and Long Island; (d) the average of Iroquois Zone 2 index and the Millennium East index for Lower Hudson Valley;[227] and (e) the Transco Zone 6 (NY) index for New York City. A 6.9 percent tax rate is also reflected in the natural gas prices for New York City.

Figure A-1: Average All-In Price by Region

2011 - 2018

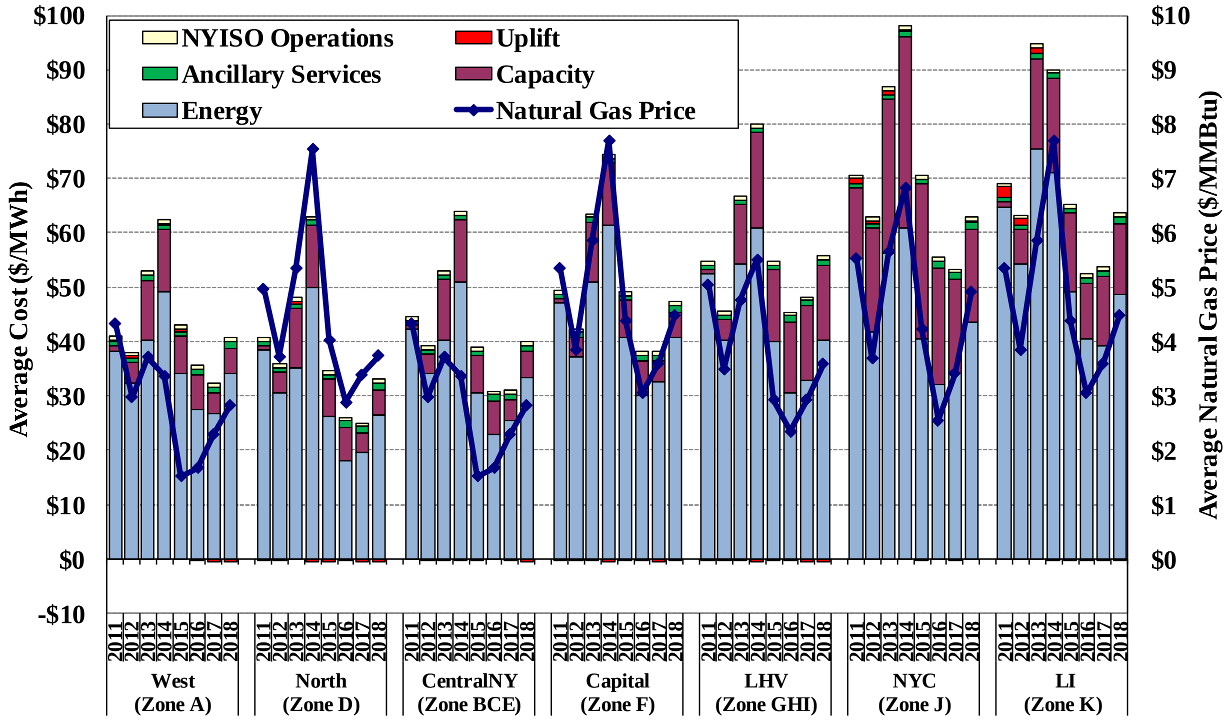


Table A-1: Average Fuel Prices and Real-Time Energy Prices

Table A-1 shows the average gas and real-time energy prices in 2017 and 2018 on an annual basis and for the month of January as well. The table also shows representative gas price indices that are associated with each of the five regions.

227 The liquidity at the Millennium index prior to summer 2012 was significantly less than exists today. Days without prices prior to June 2012 at the Millennium index were calculated instead using the Tetco M3 index price.

Table A-1: Average Natural Gas Prices and Real-Time Energy Prices
2017-2018

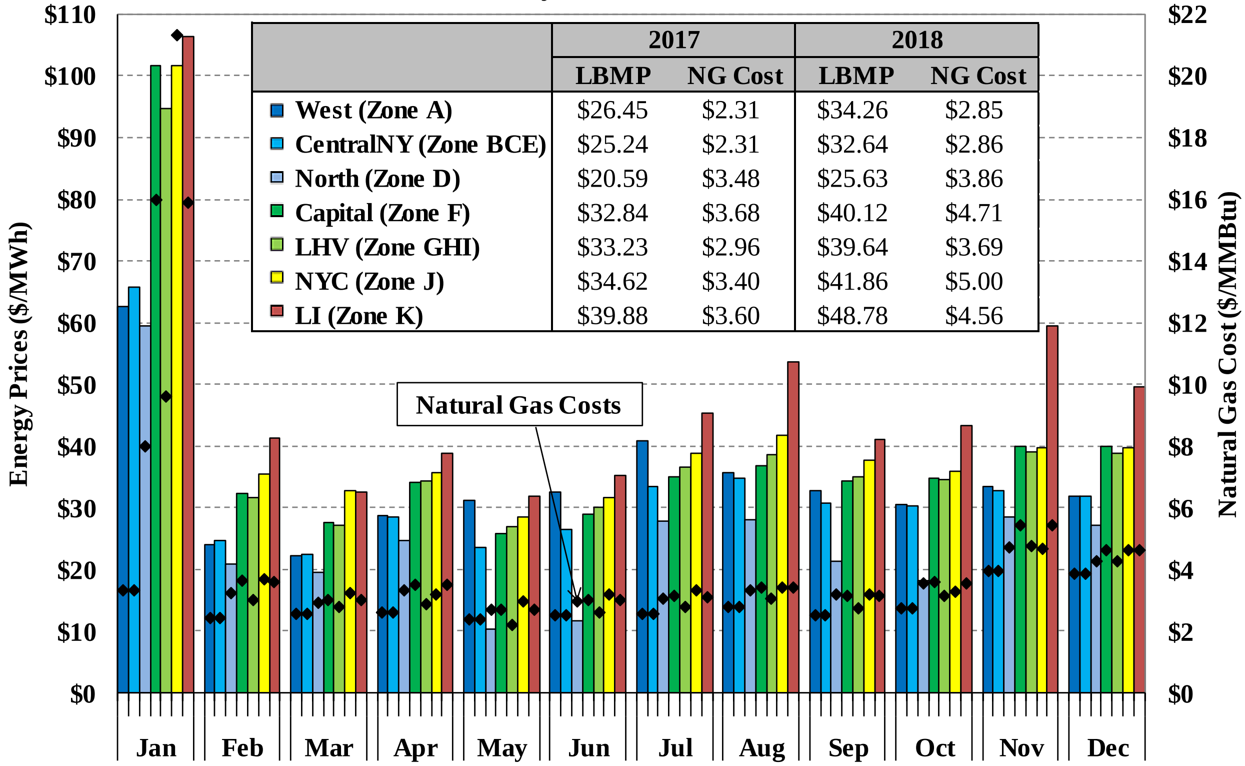
	Annual Average			January Average			Rest-of-Year Average		
	2017	2018	% Change	2017	2018	% Change	2017	2018	% Change
Gas Prices ($/MMBtu)									
Dominion North	$2.10	$2.64	26%	$2.95	$3.09	5%	$2.02	$2.59	28%
Millenium East	$2.06	$2.48	21%	$2.92	$3.00	3%	$1.98	$2.44	23%
Transco Z6 (NY)	$2.99	$4.39	47%	$3.82	$18.73	390%	$2.91	$3.09	6%
Iroquois Z2	$3.39	$4.28	26%	$4.66	$14.65	214%	$3.27	$3.34	2%
Tennessee Z6	$3.78	$5.07	34%	$5.41	$17.59	225%	$3.63	$3.93	8%
Energy Prices ($/MWh)									
West (Dominion)	$26.83	$34.13	27%	$28.46	$66.95	135%	$26.32	$30.33	15%
Capital Zone (Iroquois)	$32.65	$40.74	25%	$40.51	$109.34	170%	$29.35	$32.90	12%
Lw. Hudson (Millen. East/Iroq.)	$32.83	$40.36	23%	$38.62	$101.56	163%	$30.24	$33.53	11%
New York City (Transco)	$34.11	$43.63	28%	$38.59	$108.28	181%	$34.84	$38.10	9%
Long Island (Iroquois)	$39.20	$48.58	24%	$41.38	$108.32	162%	$38.28	$41.90	9%

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 2018 for the seven locations shown in Figure A-1. The table overlapping the chart shows the annual averages of natural gas costs and LBMPs for 2017 and 2018. Although hydro and nuclear generators produce much of the electricity used by New York consumers, natural gas units usually set the energy price as the marginal unit, especially in Eastern New York.[228]

228 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.

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2018



	2017		2018	
	LBMP	NG Cost	LBMP	NG Cost
West (Zone A)	$26.45	$2.31	$34.26	$2.85
CentralNY (Zone BCE)	$25.24	$2.31	$32.64	$2.86
North (Zone D)	$20.59	$3.48	$25.63	$3.86
Capital (Zone F)	$32.84	$3.68	$40.12	$4.71
LHV (Zone GHI)	$33.23	$2.96	$39.64	$3.69
NYC (Zone J)	$34.62	$3.40	$41.86	$5.00
LI (Zone K)	$39.88	$3.60	$48.78	$4.56

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).[229] Thus, if the electricity price is $50 per MWh, the VOM cost is $3 per MWh, the natural gas price is $5 per MMBtu, and the RGGI clearing price is $3 per CO_2 allowance, this would imply that a generator with a 9.1 MMBtu per MWh heat rate is on the margin.[230]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2018 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 2017 and in 2018 at these seven locations.

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

230 In this example, the implied marginal heat rate is calculated as ($50/MWh – $3/MWh) / ($5/MMBtu + $3/ton * 0.06 ton/MMBtu emission rate), which equals 9.1 MMBtu per MWh.

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, 2018

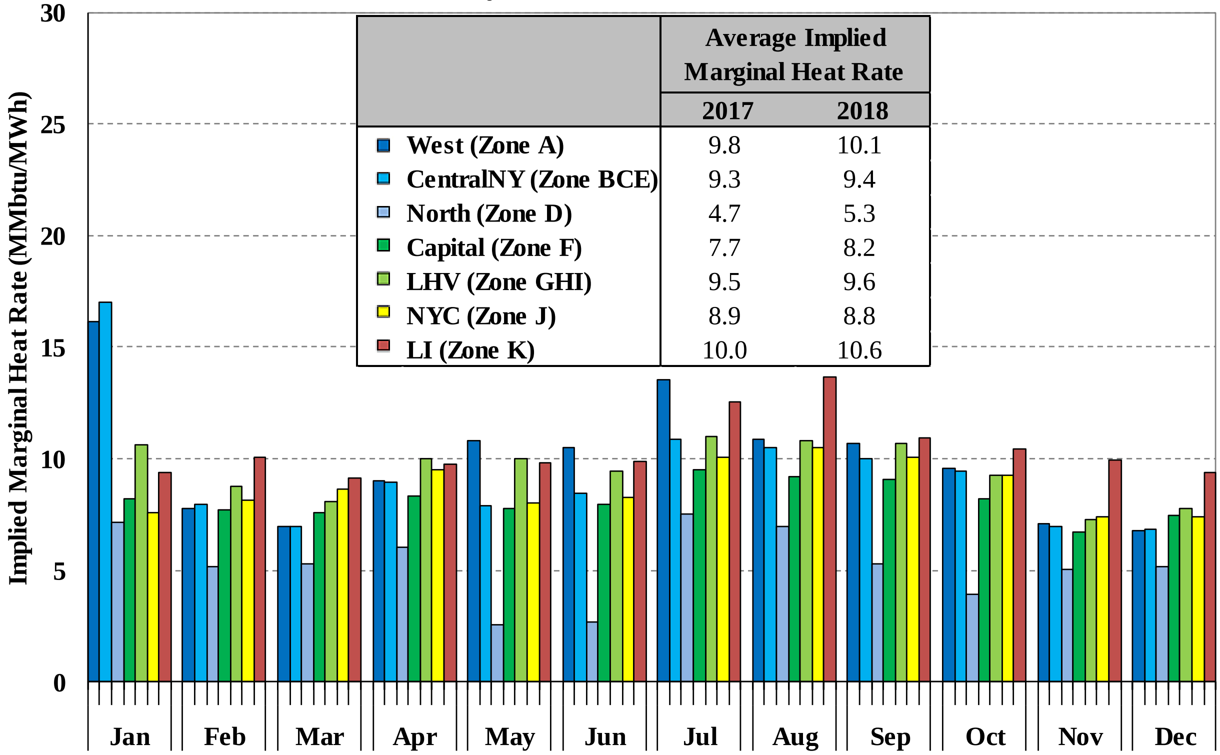


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours in recent years and at different locations. Figure A-4 shows seven price duration curves for 2018, 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 2018 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 power 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.[231] Fuel price changes from year to year are more apparent in the flatter portion of the price duration curve, since fuel price changes affect power prices most in these hours.

Figure A-4: Real-Time Price Duration Curves by Region
2018

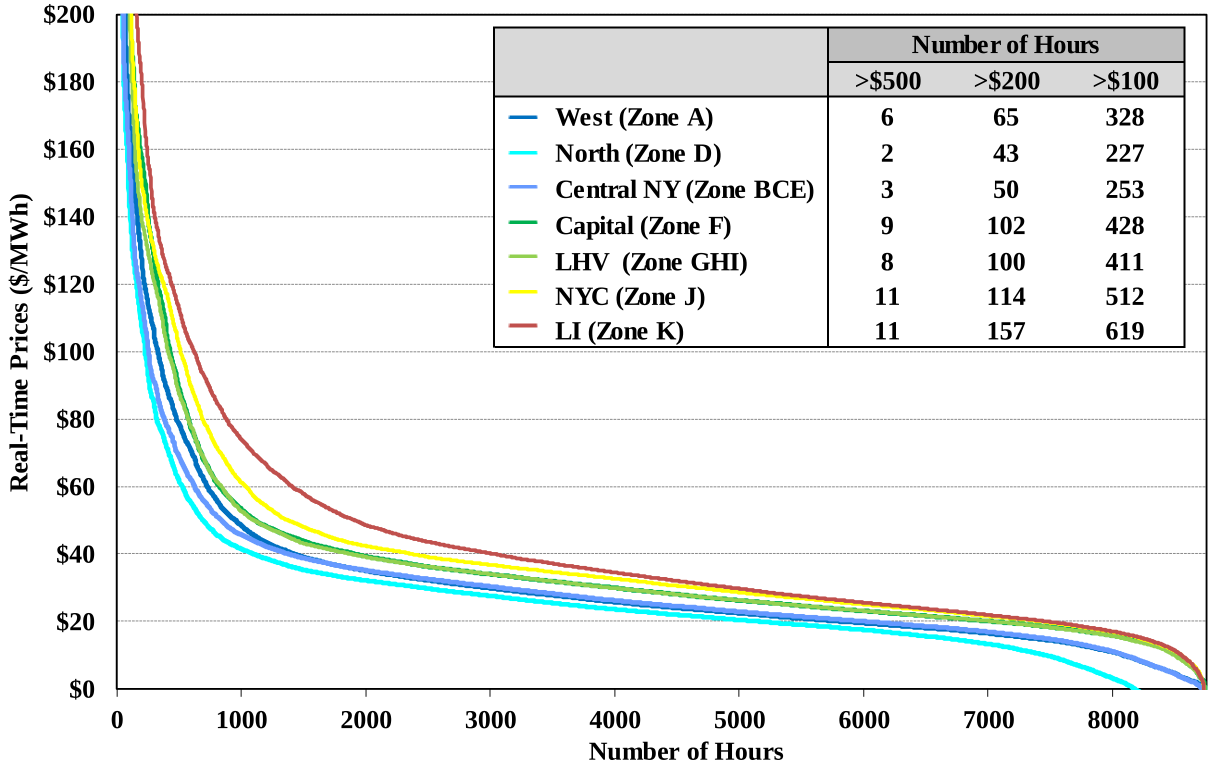
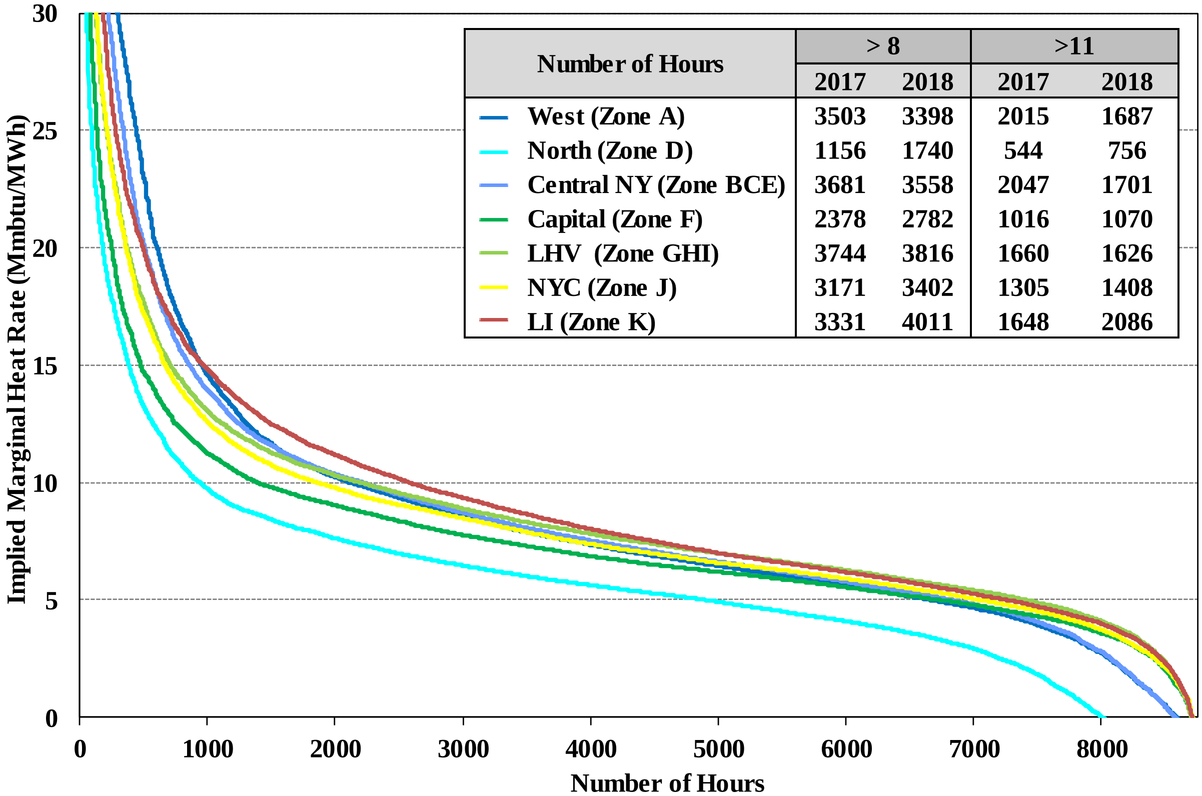


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2018. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation 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 2017 and 2018.

231 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
2018



Number of Hours	> 8		>11	
	2017	2018	2017	2018
West (Zone A)	3503	3398	2015	1687
North (Zone D)	1156	1740	544	756
Central NY (Zone BCE)	3681	3558	2047	1701
Capital (Zone F)	2378	2782	1016	1070
LHV (Zone GHI)	3744	3816	1660	1626
NYC (Zone J)	3171	3402	1305	1408
LI (Zone K)	3331	4011	1648	2086

<u>Key Observations: Wholesale Market Prices</u>

- Average all-in prices of electricity ranged from roughly \$32/MWh in the North Zone to \$64/MWh in Long Island in 2018.
  - All-in prices rose in all regions from 2017 to 2018. The prices in downstate regions (Zones G-K) rose by 16 to 19 percent, while the prices in upstate regions (Zones A-F) rose by 25 to 33 percent.
- Energy prices accounted for 69 to 76 percent of the all-in prices in the downstate regions, and 82 to 86 percent of all-in prices in upstate regions.
  - Energy prices in all regions increased by 23 to 36 percent from 2017 to 2018, largely due to higher natural gas prices in 2018. The extended cold spell in January 2018, which saw an increase of more than 200 percent in downstate natural gas prices, accounted for most of the year-over-year increase in energy prices.
    - Higher load levels during the summer months further contributed to higher energy prices (see subsection D).
    - Outages of transmission lines coming south from the North Zone resulted in significant congestion and very low energy prices in the North Zone, particularly in May and June.

- Capacity costs accounted for 21 to 27 percent of the all-in price in downstate regions and 10 to 14 percent of the all-in price in the upstate regions.
  - Capacity costs fell slightly in both the Lower Hudson Valley and in New York City (1 and 2 percent, respectively) but rose marginally in Long Island (3 percent).
  - The largest change in capacity costs from 2017 to 2018 occurred in the Rest of State regions where costs rose by 25 percent. The increase in Rest of State prices was largely driven by reduced capacity imports into New York from neighboring control areas (see Section VI.D in the Appendix).
- The average implied marginal heat rates rose from 2017 to 2018 in most regions.
  - These increases were primarily due to higher load levels, especially during the summer months.
  - The average implied marginal heat rate in the North Zone was substantially lower than in other regions, indicating that gas-fired resources in this area were rarely economic.

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 gas prices, have been the primary driver of changes in wholesale power prices over the past several years.[232] This is because fuel costs accounted 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, at most times of the year, means they default to burning natural gas. Situations do arise, however, where some generators may burn oil even when it is more expensive.[233] Since most large steam units can burn either residual fuel oil (No.6) or natural gas, the effects of natural gas price spikes on power prices during periods of high volatility are partly mitigated by generators switching to fuel oil.

Natural gas price patterns are normally relatively consistent between different regions in New York, with eastern regions typically having a small premium in price to the western zones. However, bottlenecks on the natural gas system can sometimes 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

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232 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 power prices.

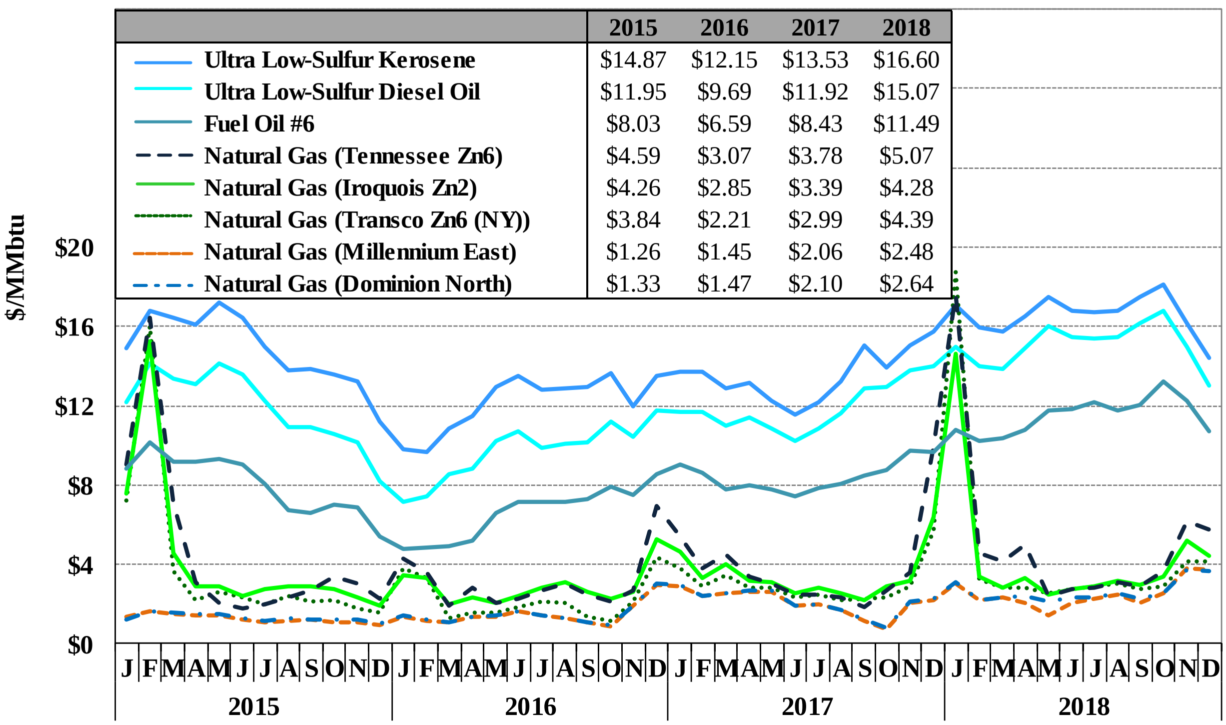
233 For instance, if natural gas is difficult to obtain on short notice, or if there is uncertainty about its availability. In addition, New York City and Long Island reliability rules sometimes require that certain units burn oil to limit the exposure of the electrical grid to possible disruptions in the supply of natural gas.

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 gas prices 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 gas prices in Capital Zone and Long Island;
- Iroquois Zone 2 prices and Millennium East prices are generally representative of natural gas prices in the Lower Hudson Valley; and
- Dominion North prices are representative of prices in portions of Western New York.

Figure A-6 shows average natural gas and fuel oil prices by month from 2015 to 2018. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices [234]
2015 – 2018



	2015	2016	2017	2018
Ultra Low-Sulfur Kerosene	$14.87	$12.15	$13.53	$16.60
Ultra Low-Sulfur Diesel Oil	$11.95	$9.69	$11.92	$15.07
Fuel Oil #6	$8.03	$6.59	$8.43	$11.49
Natural Gas (Tennessee Zn6)	$4.59	$3.07	$3.78	$5.07
Natural Gas (Iroquois Zn2)	$4.26	$2.85	$3.39	$4.28
Natural Gas (Transco Zn6 (NY))	$3.84	$2.21	$2.99	$4.39
Natural Gas (Millennium East)	$1.26	$1.45	$2.06	$2.48
Natural Gas (Dominion North)	$1.33	$1.47	$2.10	$2.64

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

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2018 as well as for NYCA as a whole.[235] The table in the chart shows annual average generation by fuel type from 2015 to 2018.

Figure A-7: Generation by Fuel Type in New York

By Quarter by Region, 2018

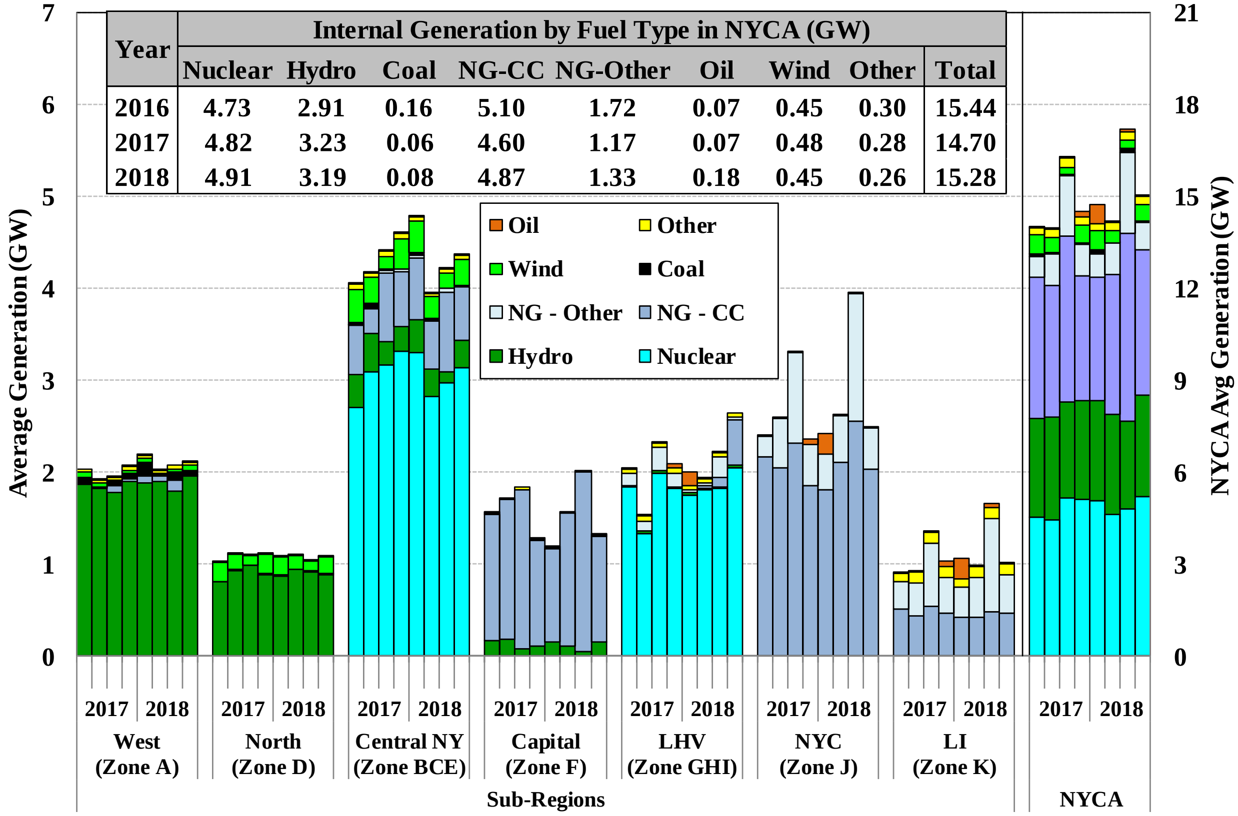


Figure A-8 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2018. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may 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 the vast majority of intervals; or (b) shortage pricing of ancillary services or transmission constraints in a small share of intervals.

The fuel type for each generator in both charts is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").

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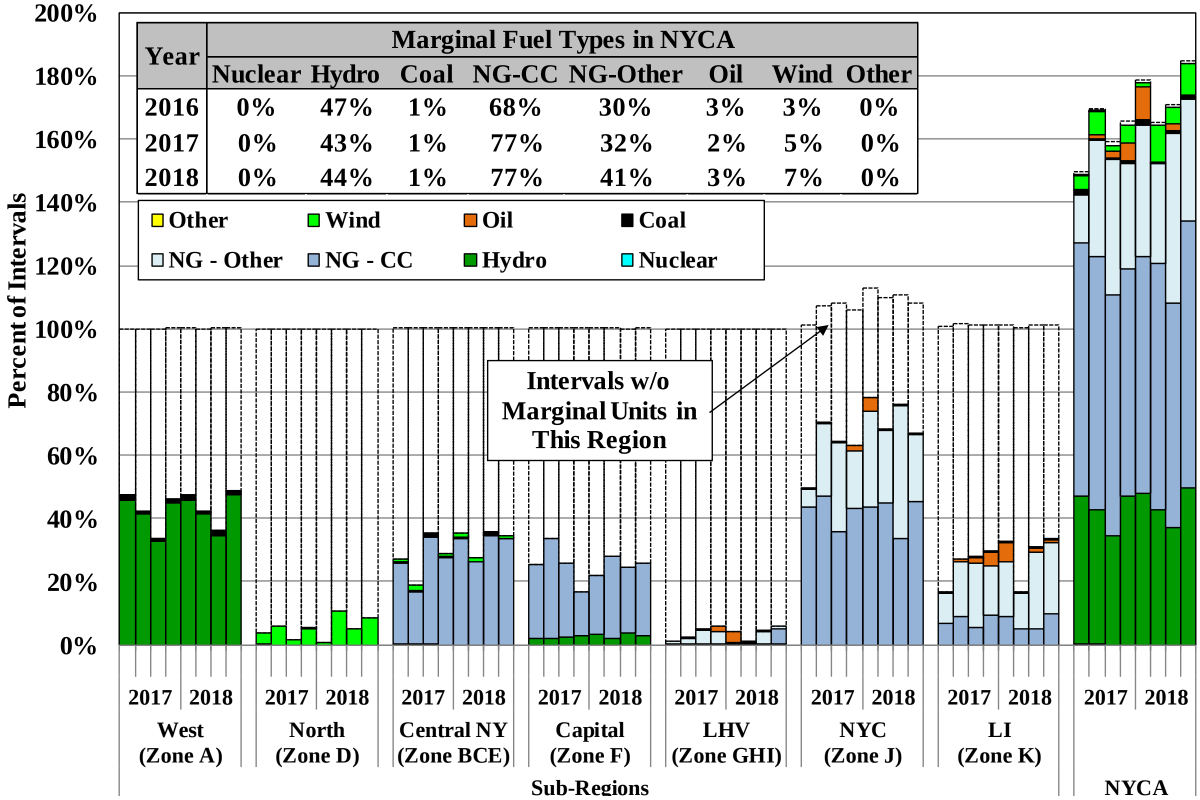
235 Pumped-storage resources in pumping mode are treated as negative generation. The "Other" category includes methane, refuse, solar, and wood.

Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2018



Key Observations: Fuel Prices and Generation by Fuel Type

- Natural gas prices, which have a strong effect on wholesale energy prices, exhibited significant variations over time and between regions in recent years.
  - These variations affected generation patterns, import levels, congestion patterns, energy price spreads, and uplift charges, which are discussed throughout the report.
- Average natural gas prices rose by 21 to 47 percent across the system from 2017 to 2018, with varying degrees of pipeline congestion in 2018.
  - The spread between Western NY gas indices (such as Millennium East) and Eastern NY gas indices (such as Transco Z6 NY) increased in 2018 compared to the previous year.[236] For instance, the Millennium East index exhibited an average discount of 43 percent relative to the Transco Zone 6 NY index in 2018 compared to an average discount of 31 percent in 2017.

236 However, this increase in price spread is attributable almost exclusively to the January cold spell which saw high volatility in Eastern NY fuel prices. Removing the effects of January, this spread actually diminished in most of the other eleven months of 2018 relative to the spreads witnessed in similar periods of 2017.

  - The Transco Zone 6 NY index exhibited an average premium of 3 percent relative to the Iroquois Zone 2 index in 2018, which is a shift in ranking from 2017 when Transco Z6 NY was priced at a 12 percent discount to Iroquois Zone 2.[237]

- Gas-fired (41 percent), nuclear (32 percent), and hydro (21 percent) generation accounted for 94 percent of all internal generation in New York during 2018.
  - Average nuclear generation rose 100 MW from 2017, reflecting fewer maintenance and refueling outages at multiple units across the year.
  - Coal-fired generation did not change much from 2017, reflecting that low LBMPs in the West Zone made it frequently uneconomic.
  - Gas-fired production rose from 2017 levels, but remained well below 2016 levels.
    - The increase in 2018 was driven by higher load levels, which required additional output from gas-fired peakers and steam turbines, especially in NYC and Long Island.
    - In addition, the commencement of operations at the CPV Valley combined cycle facility in the Lower Hudson Valley increased production from gas-fired CCs during the third and fourth quarters.
  - Average oil-fired generation increased by 110 MW (or roughly 170 percent) from 2017 levels.
    - Frequent congestion and flow restrictions on the gas pipelines in January forced dual-fuel generators, especially in downstate regions, to operate on oil for large stretches of time.
  - Average hydro generation was similar to levels witnessed in 2017.

- Gas-fired and hydro resources continued to be marginal the vast majority of time in 2018.
  - Most hydro units on the margin have storage capacity, leading them to offer based partly on the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by natural gas prices.

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

[237] For eleven months of the 2018 calendar year, the average index price at Transco Zone 6 NY was roughly equivalent to or less than the average price at Iroquois Zone 2. However, a 28 percent premium in January 2018 was enough to make Transco Z6 NY the higher priced index for the year which has not occurred on an annual basis in recent years.

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:

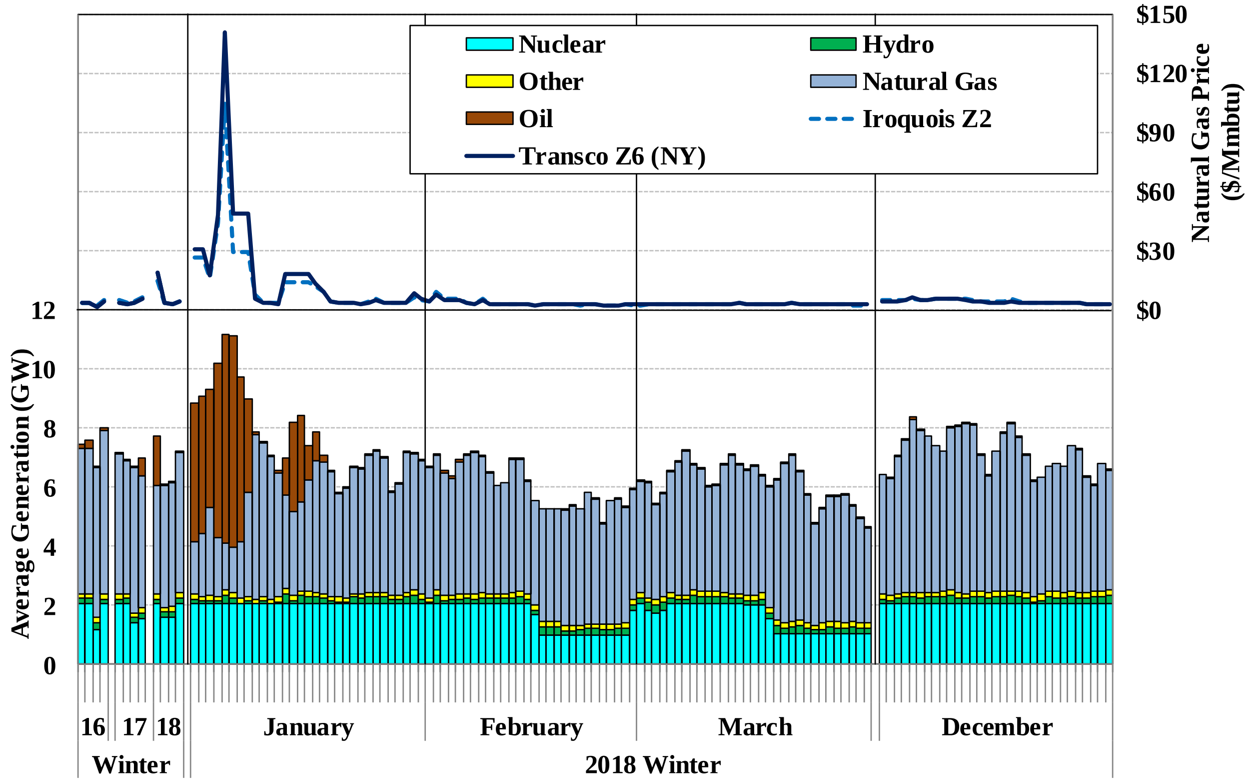
- Not having the necessary air permits;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and
- NOx emissions limitations.

This subsection examines actual fuel usage in the winter of 2018, focusing on days when supply of natural gas was very tight. This 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 2018 (including the months of January, February, March, and December). 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 2016 and 2018. 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.

Figure A-9: Actual Fuel Use and Natural Gas Prices
Eastern New York, Winter Months, 2018



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Oil-fired generation in Eastern New York totaled roughly 1,266 GWh in the four-month period (i.e., January to March, and December) of 2018, up sharply from the 473 GWh in the same period of 2017.
  - Gas supply constraints became severe during the two-week period from December 27, 2017 to January 9, 2018, which accounted for most of the oil-use during winter months in 2017 and 2018.
  - During this period, delivered gas prices exceeded $16/MMBtu each day and were over $50/MMBtu for the five day period from January 4 to 8 (substantially higher than an annual average of less than $4.50/MMBtu for 2018).
    - Gas prices peaked during the height of the January 2018 North American Blizzard with the Transco Z6 NY index topping $140 per MMBtu on January 5.
- The large difference in the amount of oil use over the past few years illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.

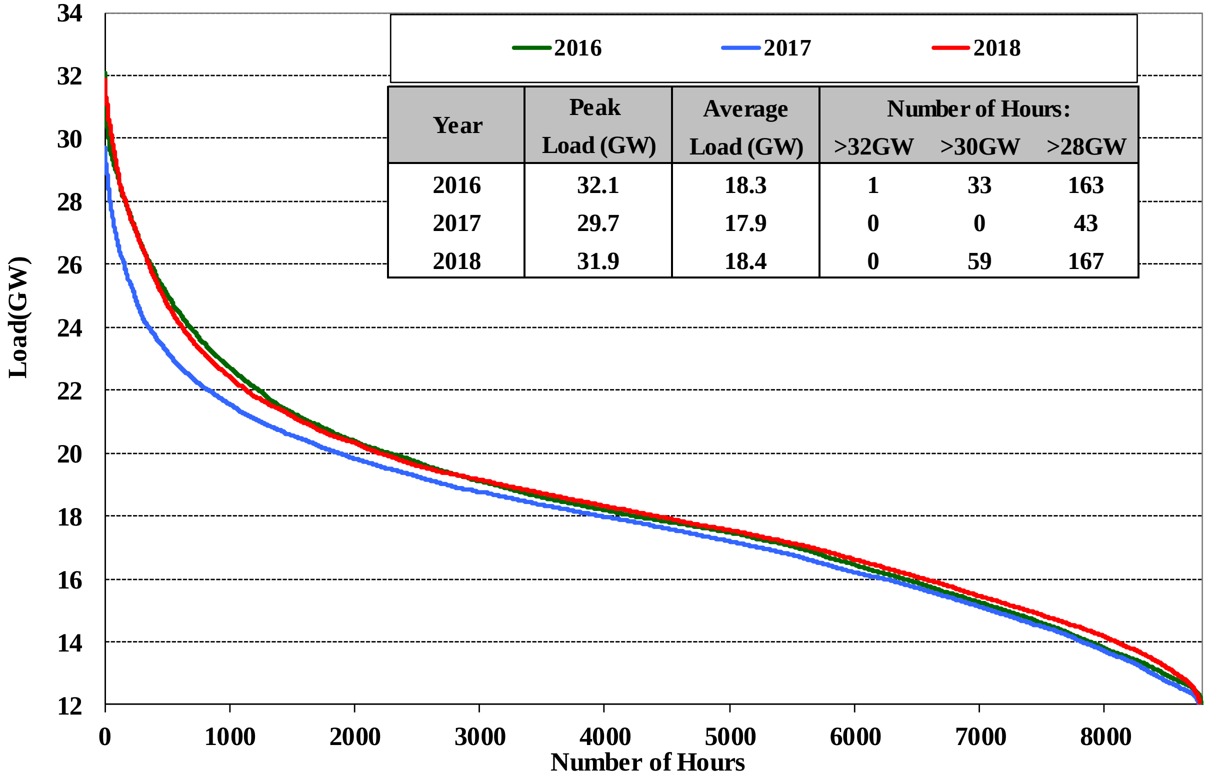
D. Load Levels

Figure A-10: 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-10 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-10: Load Duration Curves for New York State
2016 – 2018



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2016	32.1	18.3	1	33	163
2017	29.7	17.9	0	0	43
2018	31.9	18.4	0	59	167

<u>Key Observations: Load Levels</u>

- Load levels were much higher in 2018 than in 2017.
    - Average load rose 3 percent from 2017, but this was similar to average load levels witnessed in 2016.

- Annual peak load rose markedly (by 7 percent) from the low summer peak of 2017 (which was the lowest level in the past decade). The 2018 peak load was slightly lower than in 2016.[238]

E. Day-Ahead Ancillary Services Prices

Figure A-11: 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, and Southeast New York reserve prices. Figure A-11 shows the average day-ahead prices for these four ancillary services products in each month of 2017 and 2018. The prices are shown separately for the following three distinct regions: (a) Southeast New York (including Zones G-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 Southeast New York as an example,

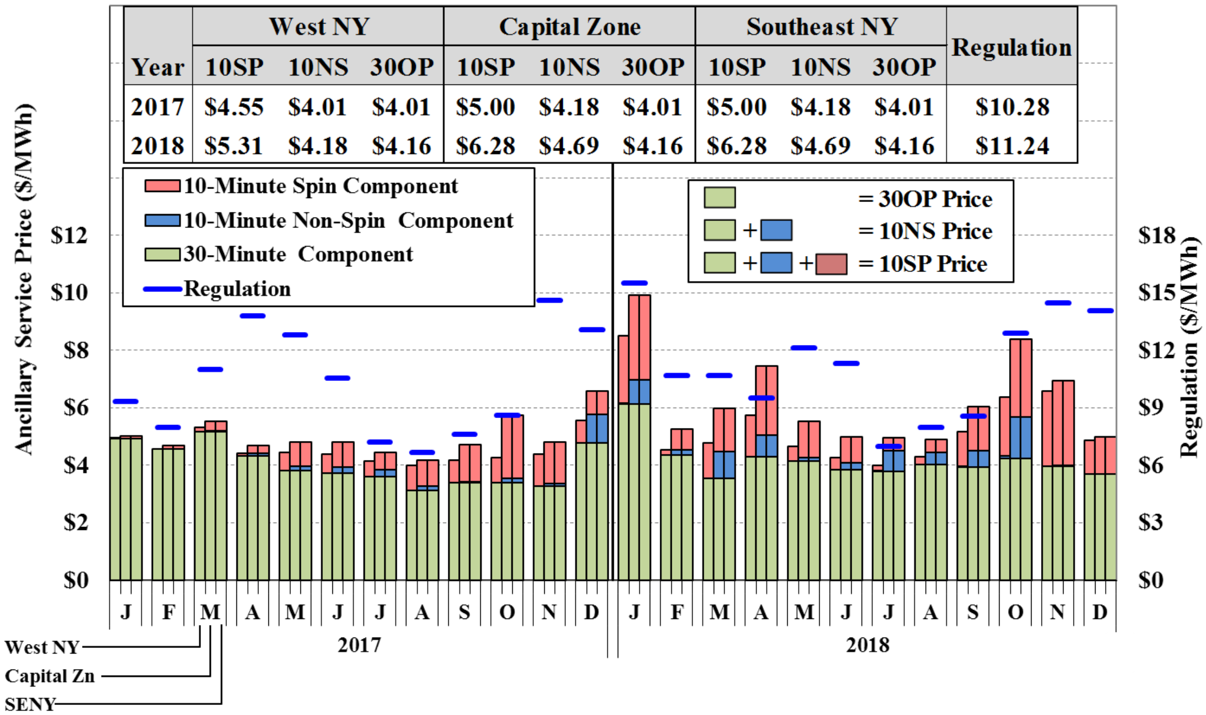
- The 30-minute component represents the cost to simultaneously meet the 30-minute reserve requirements for Southeast New York, East New York, and NYCA;
- The 10-minute non-spin component represents the cost to simultaneously meet the 10-minute total reserve requirements for East New York and NYCA (Southeast 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 (Southeast New York does not have a separate 10-minute spinning reserve requirement).

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

238 The peak load date in 2018 occurred on August 29, though several other days during the summer saw loads peak above 30 GW.

10-minute non-spin component, and the 10-minute spinning reserve price equals the sum of all three price components. The inset table compares average final prices (not the components) in 2017 and 2018 on an annual basis.

Figure A-11: Day-Ahead Ancillary Services Prices
2017- 2018



	West NY			Capital Zone			Southeast NY			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
2017	$4.55	$4.01	$4.01	$5.00	$4.18	$4.01	$5.00	$4.18	$4.01	$10.28
2018	$5.31	$4.18	$4.16	$6.28	$4.69	$4.16	$6.28	$4.69	$4.16	$11.24

Key Observations: Day-ahead Ancillary Service Prices

- The average day-ahead prices for all reserve products rose in 2018 consistent with the increase in opportunity costs associated with higher energy prices.
  - Gas supply was severely constrained in early January due to extended cold weather conditions, and again in the third week in April due to major pipeline repair work, contributing to higher reserve prices than in other months in 2018.
  - In addition, generator outages during the shoulder months in the Spring and Fall reduced the supply of reserve offers, driving up the prices of 10-minute spinning and non-spinning prices.
- Day-ahead regulation prices also increased (by an average of nine percent) in 2018 partly because of increased opportunity costs from higher energy prices and outages of regulation suppliers.
  - As observed during the shoulder months, lower load periods often exhibit higher regulation prices. The amount of online generating capacity is relatively low during these months, and more generators are on routine maintenance outages, thereby reducing the supply of regulation.

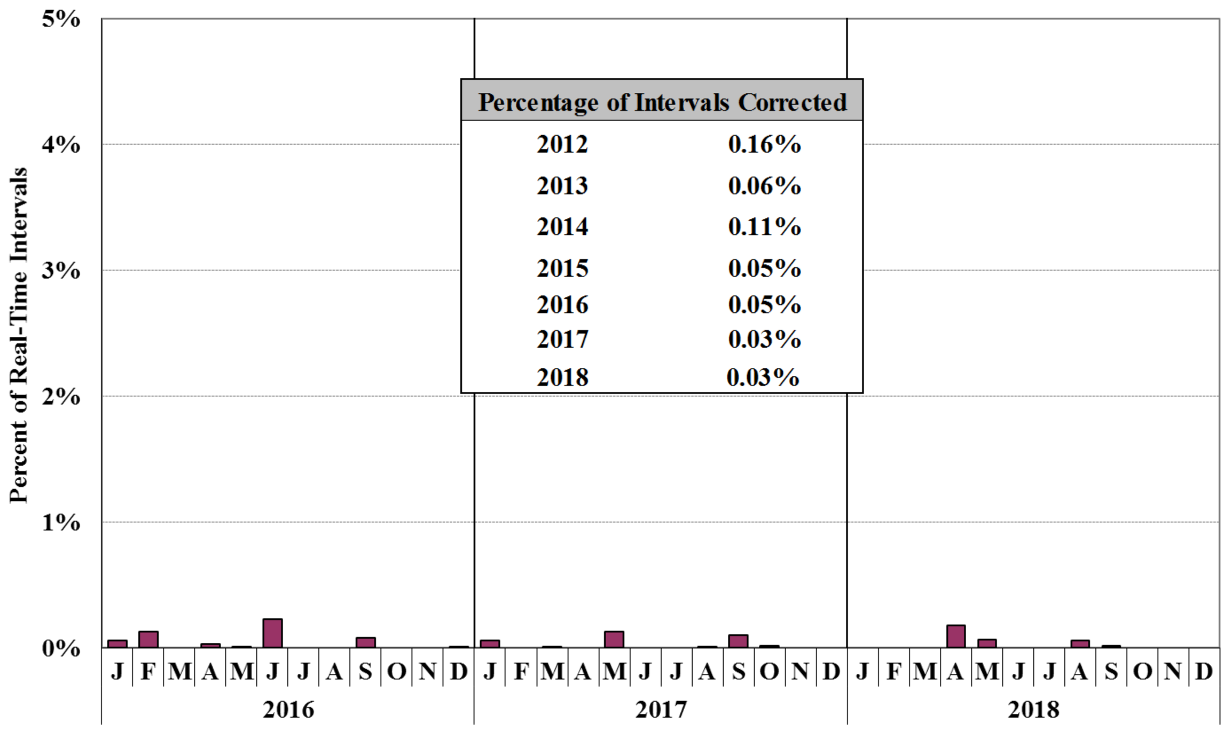
F. Price Corrections

Figure A-12: 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-12 summarizes the frequency of price corrections in the real-time energy market in each month from 2016 to 2018. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-12: Frequency of Real-Time Price Corrections
2016-2018



G. 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 they will profit from being committed. 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.

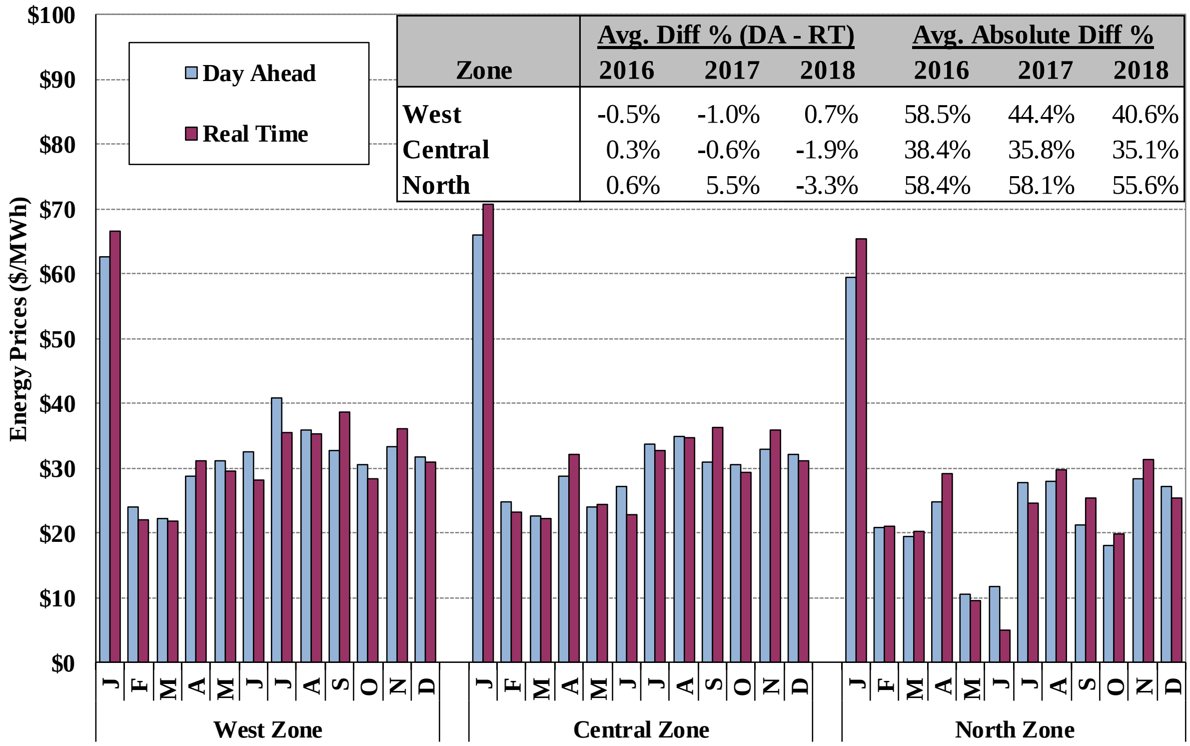
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the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

Figure A-13 & Figure A-14: 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.

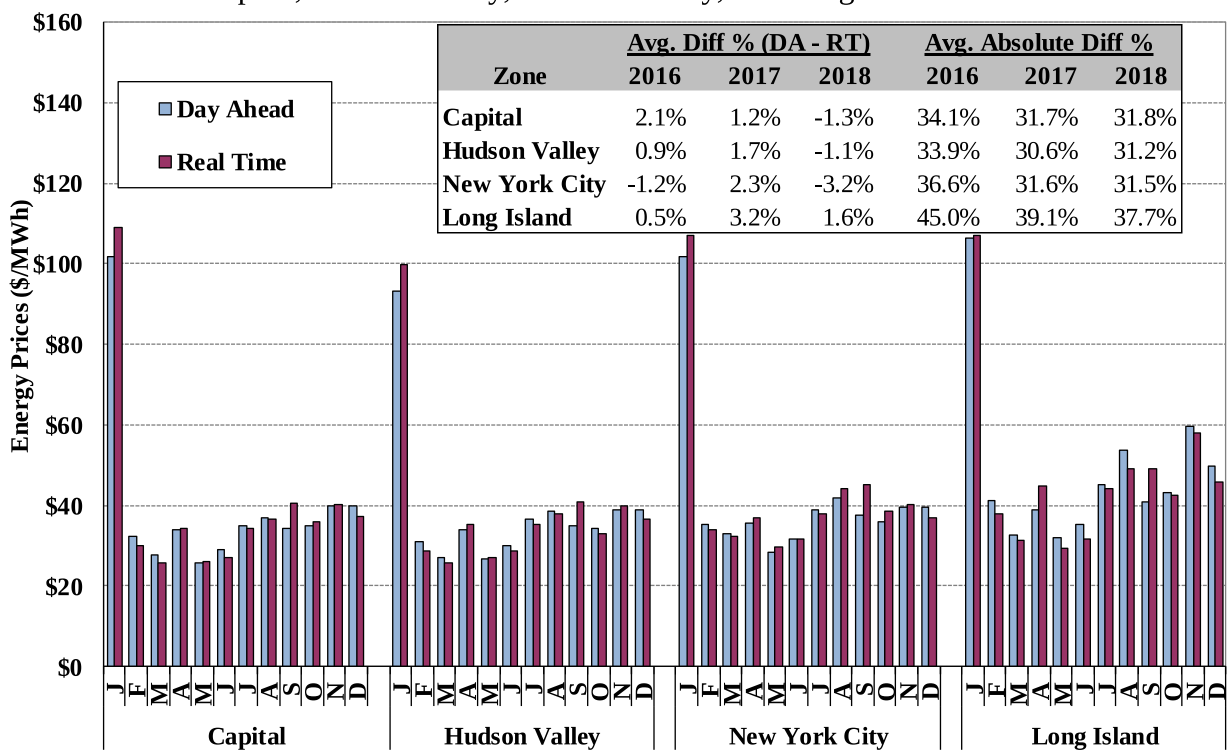
Figure A-13 and Figure A-14 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars compare the average day-ahead and real-time prices in each zone in each month of 2018. 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-13: Average Day-Ahead and Real-Time Energy Prices in Western New York
West, Central, and North Zones – 2018



Zone	Avg. Diff % (DA - RT) 2016	2017	2018	Avg. Absolute Diff % 2016	2017	2018
West	-0.5%	-1.0%	0.7%	58.5%	44.4%	40.6%
Central	0.3%	-0.6%	-1.9%	38.4%	35.8%	35.1%
North	0.6%	5.5%	-3.3%	58.4%	58.1%	55.6%

Figure A-14: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2018



Zone	Avg. Diff % (DA - RT) 2016	2017	2018	Avg. Absolute Diff % 2016	2017	2018
Capital	2.1%	1.2%	-1.3%	34.1%	31.7%	31.8%
Hudson Valley	0.9%	1.7%	-1.1%	33.9%	30.6%	31.2%
New York City	-1.2%	2.3%	-3.2%	36.6%	31.6%	31.5%
Long Island	0.5%	3.2%	1.6%	45.0%	39.1%	37.7%

Figure A-15: Average Real-Time Price Premium at Select Nodes

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.

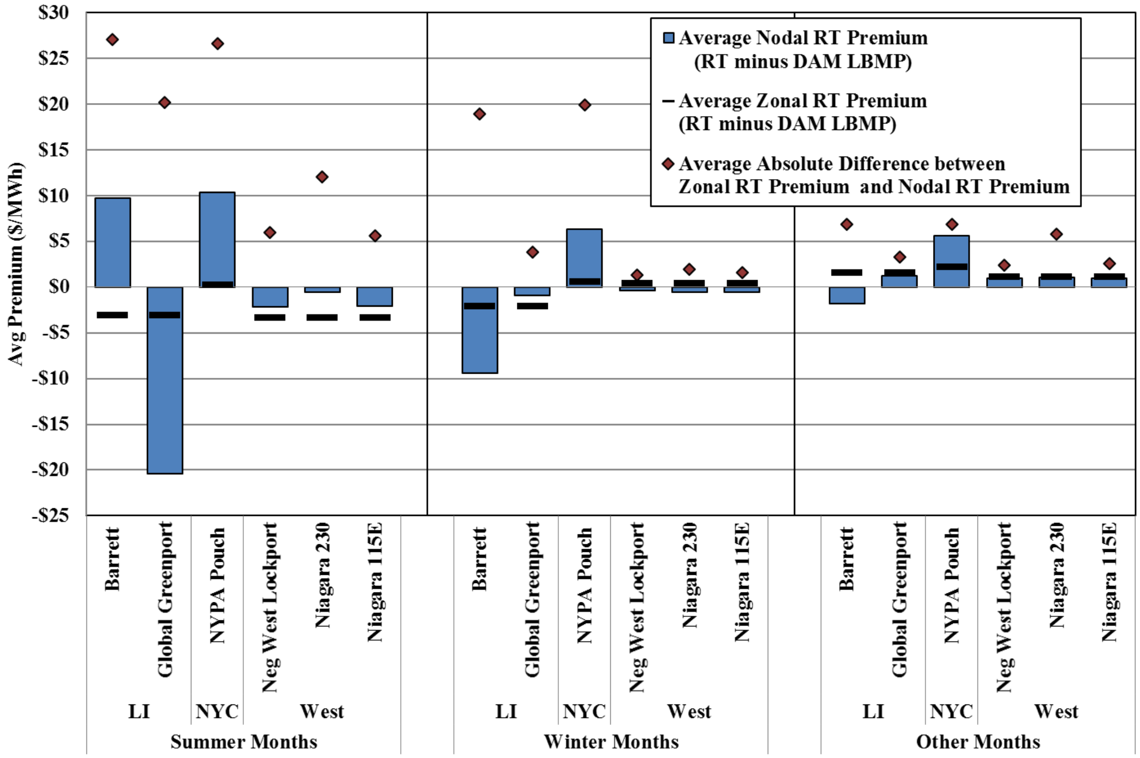
- Transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

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. This analysis examines price statistics for selected nodes throughout New York State to assess price convergence at the nodal level.

Figure A-15 shows average day-ahead prices and real-time price premiums in 2018 for selected locations in New York City, Long Island, and Upstate New York.[239] These are load-weighted averages based on the day-ahead forecasted load. The figure includes nodes in several regions that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. Due to seasonal variations in congestion patterns, these are shown separately for the summer months (June to August), the winter months (December, January, and February), and other months.

239 In New York City, NYPA Pouch is the NYPA Pouch GT 1 bus. In Long Island, Barret is the Barrett 1 bus and Global Greenport is Global Greenport GT1 bus. NEG West Lockport, Niagara 230kV, and Niagara 115kV East represent generator locations in the West Zone.

Figure A-15: Average Real-Time Price Premium at Select Nodes
2018



Key Observations: Convergence of Day-Ahead and Real-Time Energy Prices

- Average day-ahead prices were generally within one to three percent of average real-time prices in most areas in 2018. In most regions, the average difference between day-ahead and real-time prices in 2018 either narrowed or was very similar to 2017.
  - Unlike previous years, real-time prices exhibited a small premium over day-ahead prices in most regions (other than in Long Island and the West Zone) in 2018.
  - Although a small average day-ahead premium was generally desirable in a competitive market, small real-time premiums occurred largely because of real-time spikes during the cold weather in January. Removing the effects of the January cold spell would result in (a) much smaller difference in average day-ahead and real-time prices, and (b) small day-ahead premiums in several regions.
    - In addition, a major supply contingency in New England on September 3rd contributed to real-time premiums in 2018.
- At the zonal level, energy price convergence, as measured by the average absolute difference between hourly day-ahead and real-time prices, improved in the West Zone, North Zone, and Long Island from 2017 to 2018.
  - These areas frequently experienced severe congestion in real-time. The improvement in these areas was partly to due to modifications to the application of the Graduated

Transmission Demand Curve ("GTDC") in June 2017, which resulted in more predictable and transparent price signals during real-time transmission shortages (reflected in the day-ahead prices as well).

- At the nodal level, some locations in New York City and Long Island exhibited less consistency between average day-ahead and real-time prices in 2018 than at the zonal level.
  - In New York City, some nodes (e.g. NYPA Pouch) are affected differently in the day-ahead and real-time markets. These nodes are located in the load pockets that only have slow-ramping steam units and expensive quick-start resources. Transient real-time price spikes often occurred because of insufficient 5-minute ramping capability in the pockets, which led to frequent transient transmission shortages. Accordingly, real-time prices were much higher than day-ahead prices at these locations.
  - On the east end of Long Island, management of constraints on 138 kV and 69 kV circuits flowing power towards the east end of Long Island led to significant differences between day-ahead and real-time congestion pricing patterns.
    - In the day-ahead market, constraints of 138 kV circuits were managed through congestion pricing and re-dispatch, which also helped reduce constraints across parallel 69 kV circuits.
    - In the real-time market, constraints of 69 kV circuits were managed with out-of-market dispatch rather than congestion pricing and re-dispatch. Since these out-of-market actions also helped reduce flows across parallel 138 kV circuits, congestion pricing did not occur frequently in the real-time market.
    - Consequently, day-ahead prices were much higher than real-time prices at the Global Greenport bus.
  - On the west end of Long Island (e.g. Barrett), significant differences between day-ahead and real-time prices often resulted from 5-minute ramping limitation, RTC shutdown GTs, and some non-market flows (see Section V.F in the Appendix for real-time transient price spike analysis).

H. 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-16 to Figure A-19: Distribution of day-ahead price premiums for reserves

To evaluate the performance of the day-ahead ancillary service markets, the following four figures show distributions of day-ahead premiums (i.e., day-ahead prices minus real-time prices) in: (a) Western 30-minute reserve prices; (b) Western 10-minute spinning reserve prices; (c) Eastern 10-minute spinning reserve prices; and (d) Eastern 10-minute non-spin reserve prices.

In each of the four figures, the day-ahead premium is calculated at the hourly level and grouped by ascending dollar range (in $0.25 tranches). The cumulative frequency is shown on the y-axis as the percentage of hours in the year. For instance, Figure A-16 shows that the day-ahead Western 30-minute reserve prices for approximately 80 percent of hours had a day-ahead premium of $5 or less, including intervals where the day-ahead premium was negative (i.e. real-time prices exceeded day-ahead prices).

The figures compare the distributions between 2017 and 2018. The distributions between the 15th percentile and the 85th percentile are also highlighted in shaded areas for each of the years. Thus, the Western 30-minute reserves day-ahead premium was between $2.75 and $5/MWh for 70 percent of the hours in 2018 (and also in 2017). The inset tables summarize the following annual averages in 2017 and 2018: (a) the average day-ahead price; (b) the average real-time price; (c) the difference between the average day-ahead price and the real-time price; and (d) the average absolute difference between the day-ahead price and the real-time price.

Figure A-16: Day-Ahead Premiums for 30-Minute Reserves in West New York
2017 – 2018

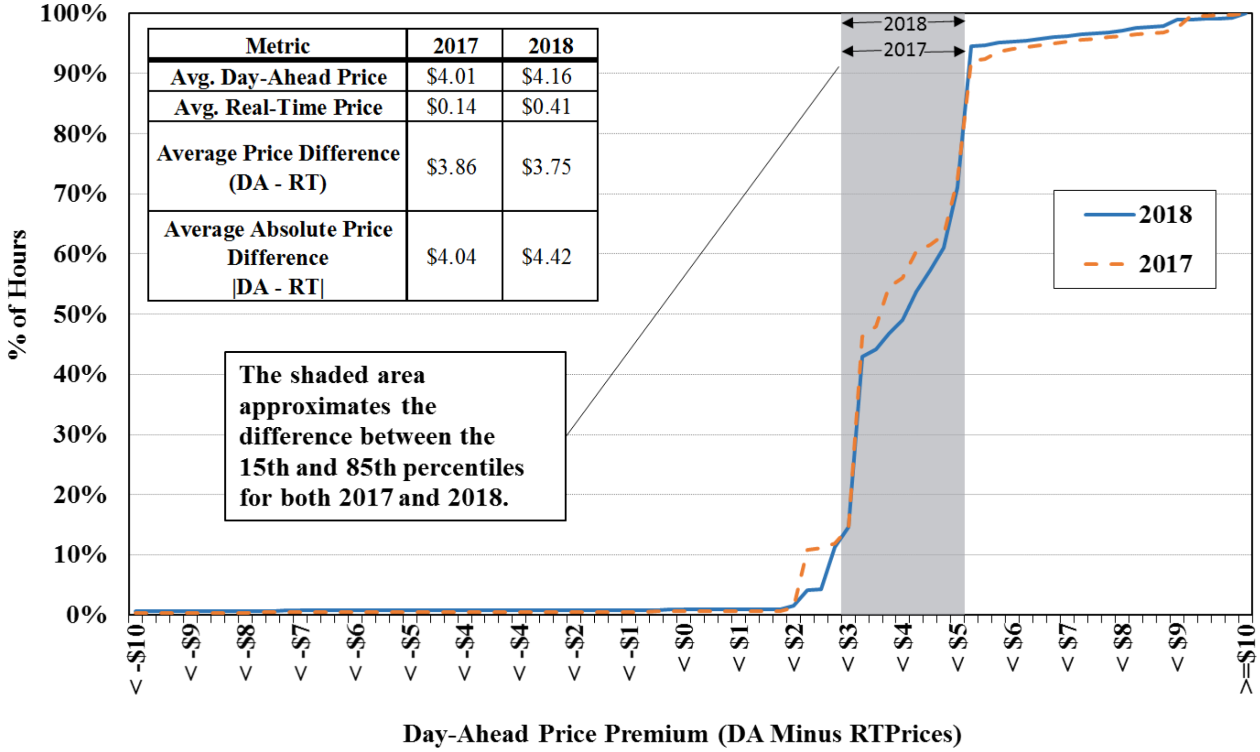


Figure A-17: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2017 - 2018

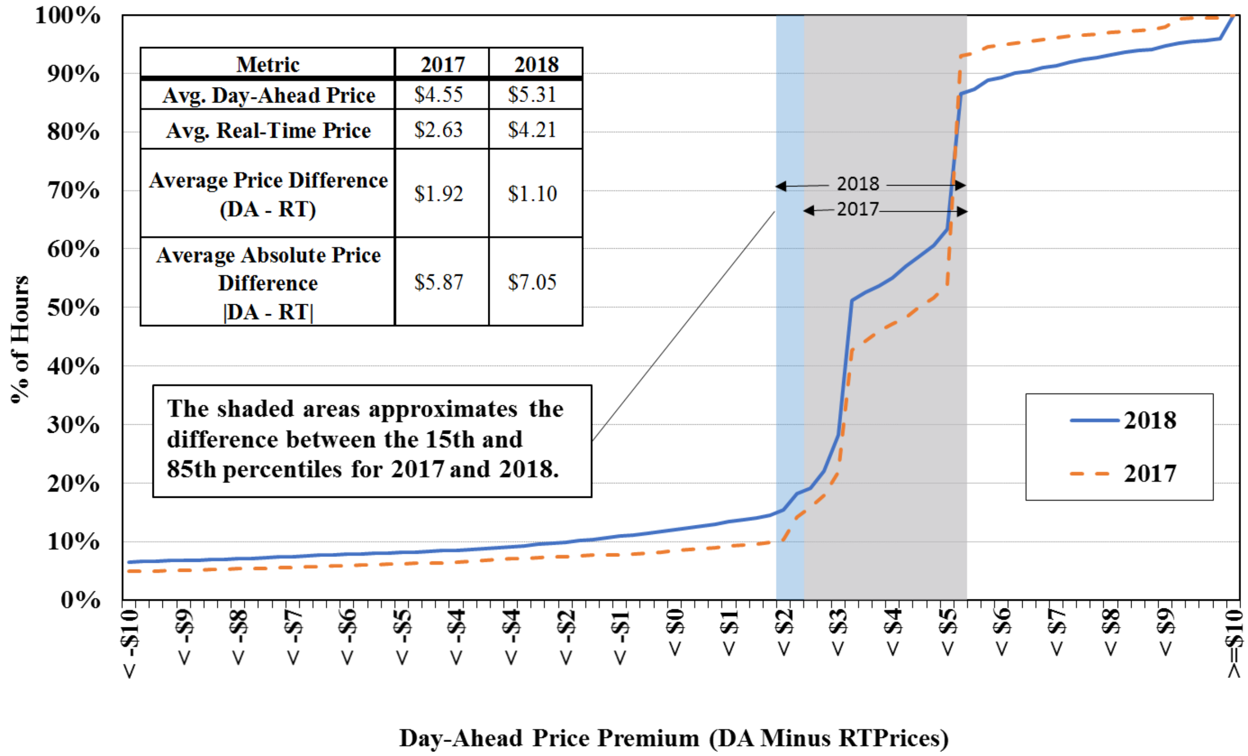


Figure A-18: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2017 – 2018

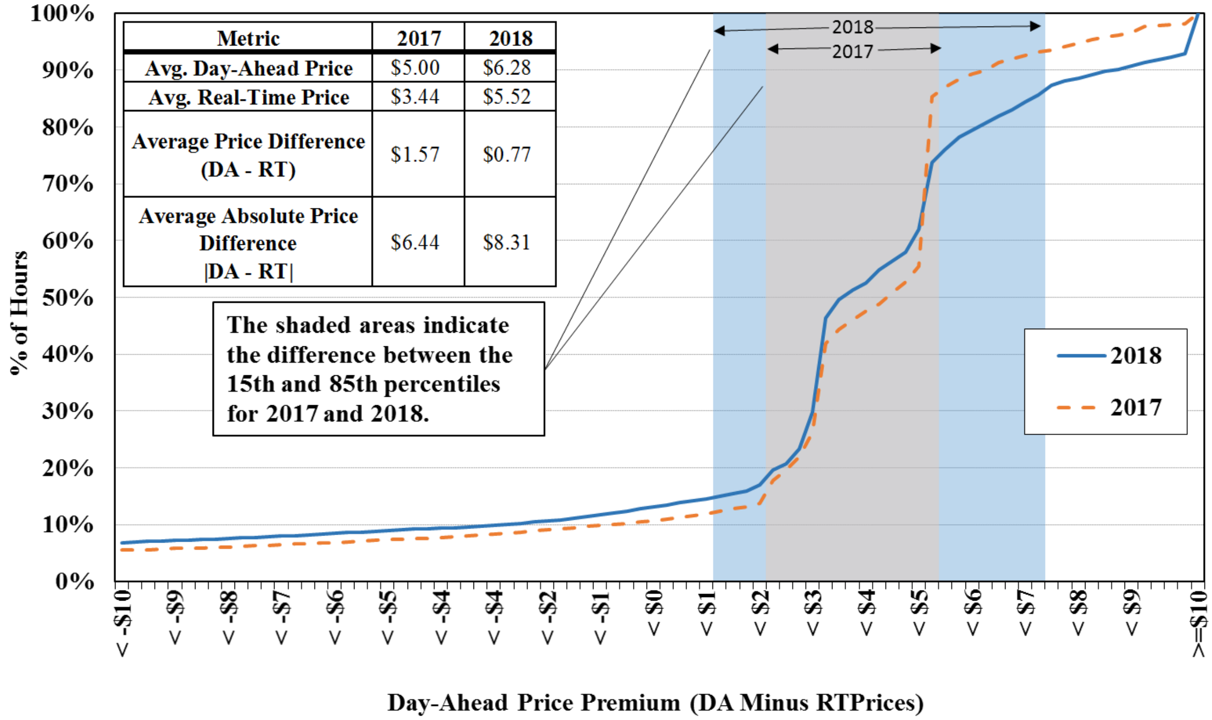
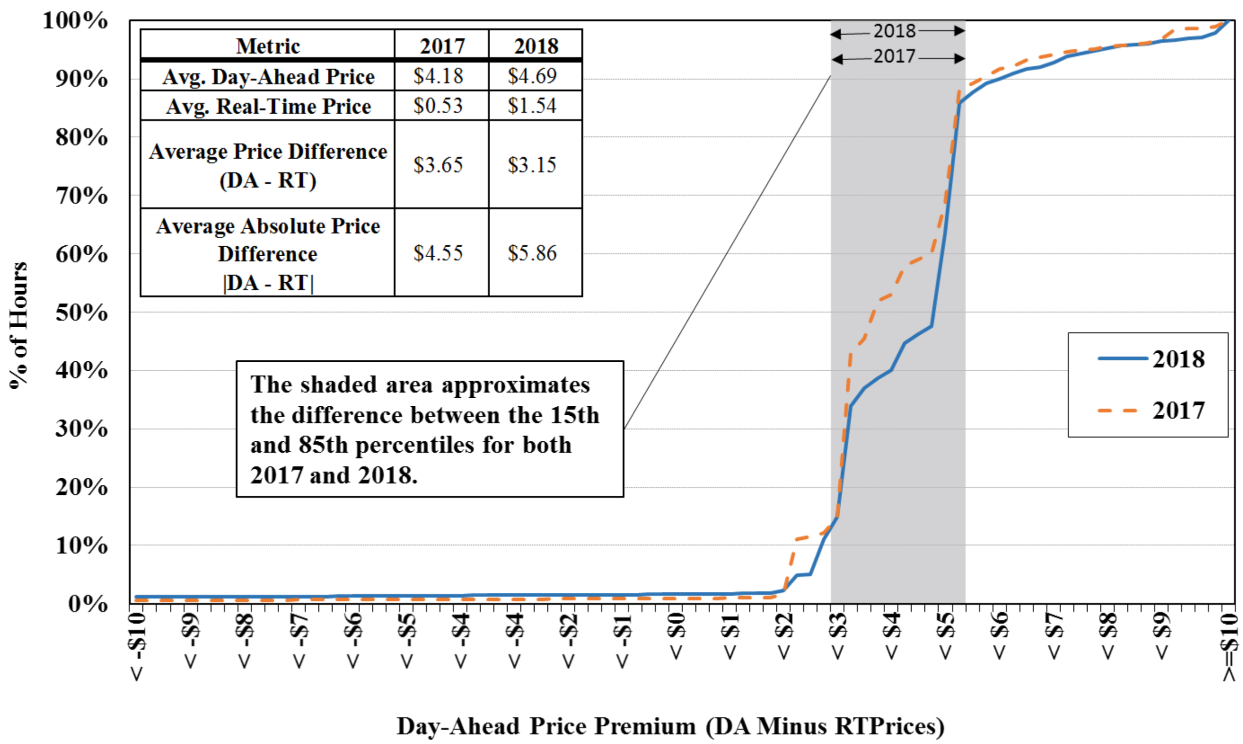


Figure A-19: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2017 – 2018



Key Observations: Day-Ahead Reserve Market Performance

- Unlike real-time reserve prices, which are only based on the opportunity cost of not serving energy (because units are deemed to have a $0 availability offer in real-time), day-ahead reserve prices also depend on suppliers' availability offers, which reflect factors such as:
  - The expected differences between day-ahead and real-time prices;
  - The costs associated with ensuring sufficient fuel is available in case the unit is converted to energy;
  - Financial risks associated with being deployed in real-time after selling reserves in the day-ahead; and
  - NYISO rules that limit the flexibility of generators' offers in real-time if a generator was scheduled for reserves in the day-ahead market.
- Although the average differences between day-ahead and real-time prices fell from 2017 to 2018 for all reserve products, the average absolute differences increased.
  - Higher real-time volatility resulted from tighter system conditions due partly to higher load levels and more peaking conditions in 2018.
    - Tight system conditions on a small number of days (due to severe cold weather, supply contingencies, and thunderstorm alerts) resulted in real-time price spikes that were not reflected in day-ahead reserve prices.
    - For instance, for 10-minute spinning reserves in Eastern New York, the average absolute difference between day-ahead and real-time reserve prices rose by 29 percent from 2017 to 2018. However, when just a dozen higher real-time reserve pricing days are excluded from the calculation, the difference between years falls to 13 percent.

I. Regulation Market Performance

Figure A-20 – Regulation Prices and Expenses

Figure A-20 shows the regulation prices and expenses in each month of 2017 and 2018. The upper portion of the figure compares the regulation capacity prices in the day-ahead and real-time markets. The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

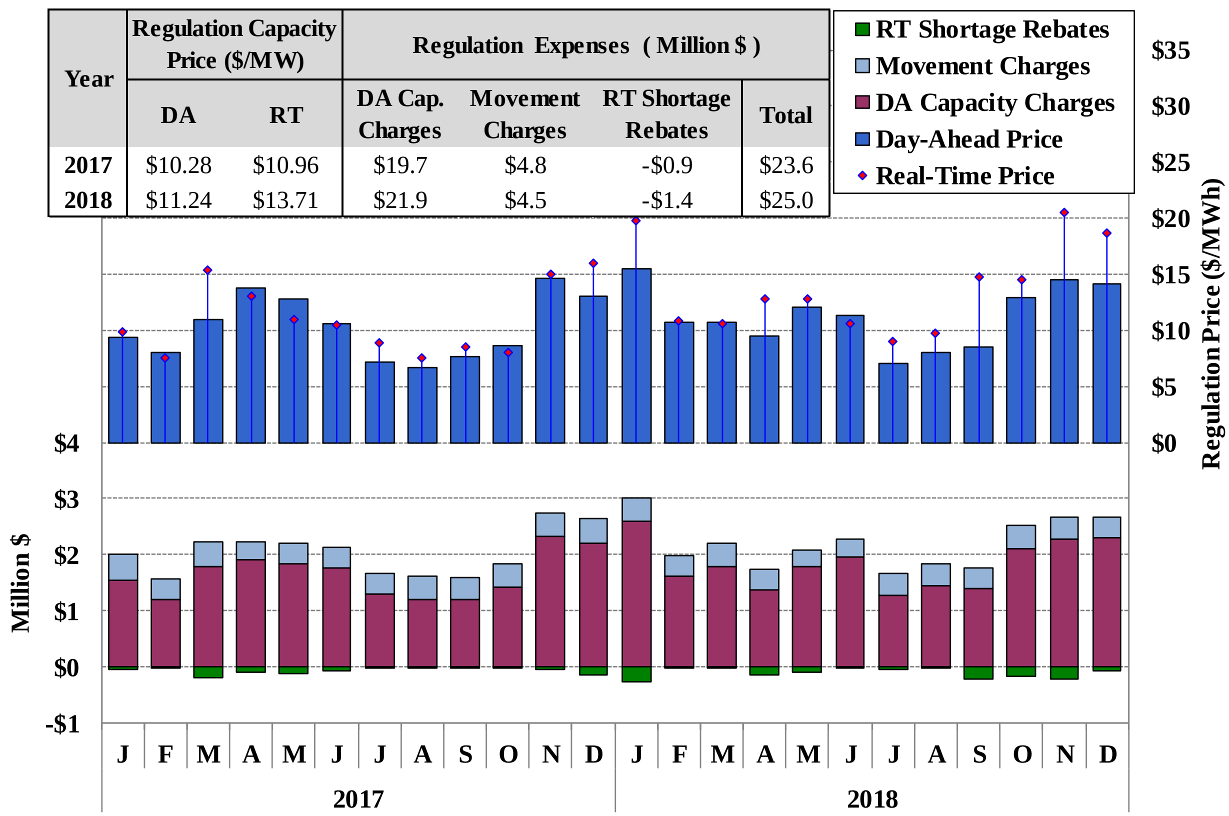
- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.

- 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-20: Regulation Prices and Expenses

by Month, 2017-2018



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2017	$10.28	$10.96	$19.7	$4.8	-$0.9	$23.6
2018	$11.24	$13.71	$21.9	$4.5	-$1.4	$25.0

Key Observations: Regulation Market Performance

- Average real-time regulation capacity prices were 22 percent higher than day-ahead prices in 2018 largely because of tight conditions arising from:
  - Increased price volatility during the January cold spell; and
  - Reduced available capacity due to maintenance outages in September and November.

- However, regulation expenses increased modestly only by 6 percent in 2018 because of higher shortage rebates resulted from more frequent regulation shortages. (see Section V.G in the Appendix)

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;
- Ancillary services 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 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. Ancillary services offer patterns 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. 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 0.

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 is 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.* [240]

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.

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240 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.

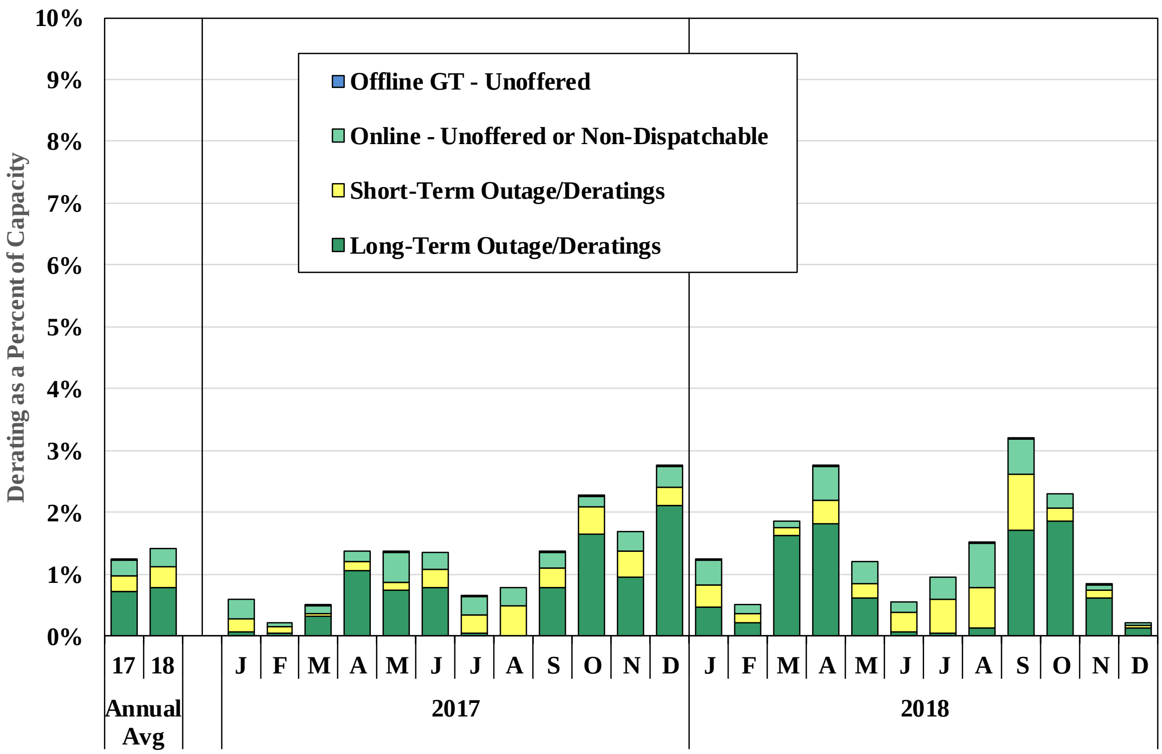
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

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.[241] 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.[242] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[243]

Figure A-21 - Figure A-22: Unoffered Economic Capacity by Month

Figure A-21 and Figure A-22 show the broad patterns of deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2017 and 2018.

Figure A-21: Unoffered Economic Capacity by Month in NYCA
2017 – 2018



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

242 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.

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

Figure A-22: Unoffered Economic Capacity by Month in East New York
2017 - 2018

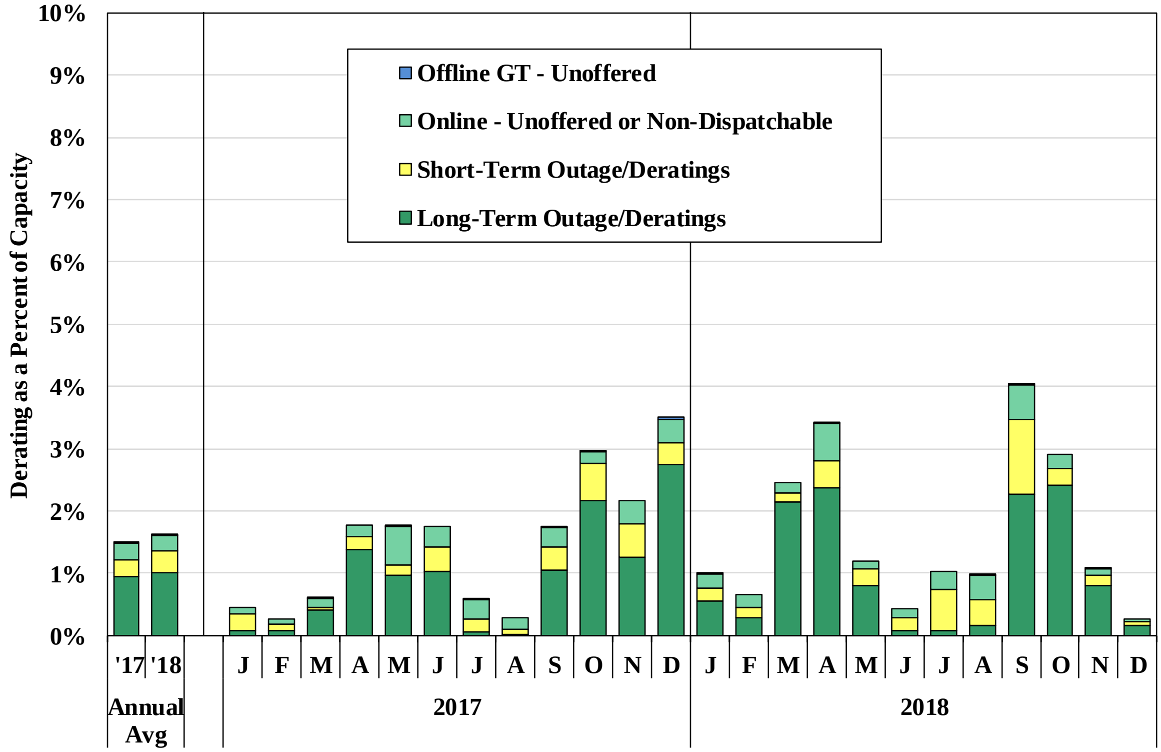


Figure A-23 & Figure A-24: Unoffered Economic Capacity by Load Level & Portfolio Size

Most wholesale electricity production comes from base-load 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.

As noted previously, a supplier with market power is most likely to profit from withholding during periods when the market supply curve becomes steep (i.e., at 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-23 and Figure A-24 to determine whether the conduct is consistent with workable competition.

Figure A-23: Unoffered Economic Capacity by Supplier by Load Level in New York
2017 – 2018

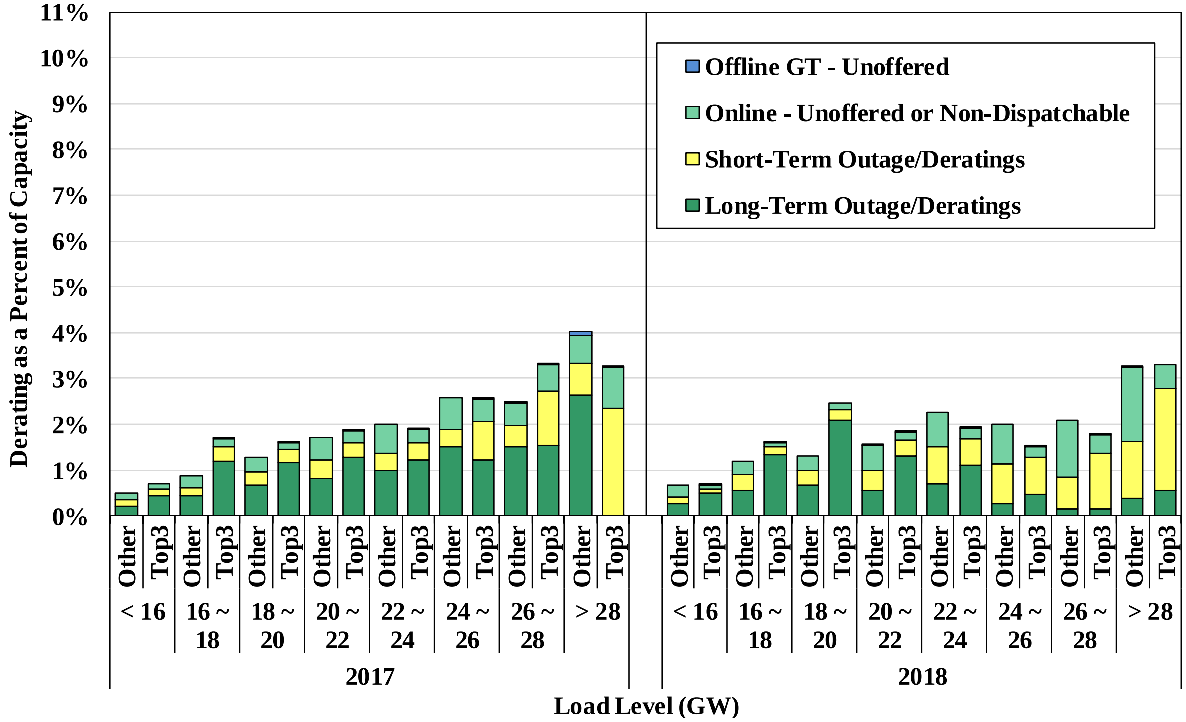
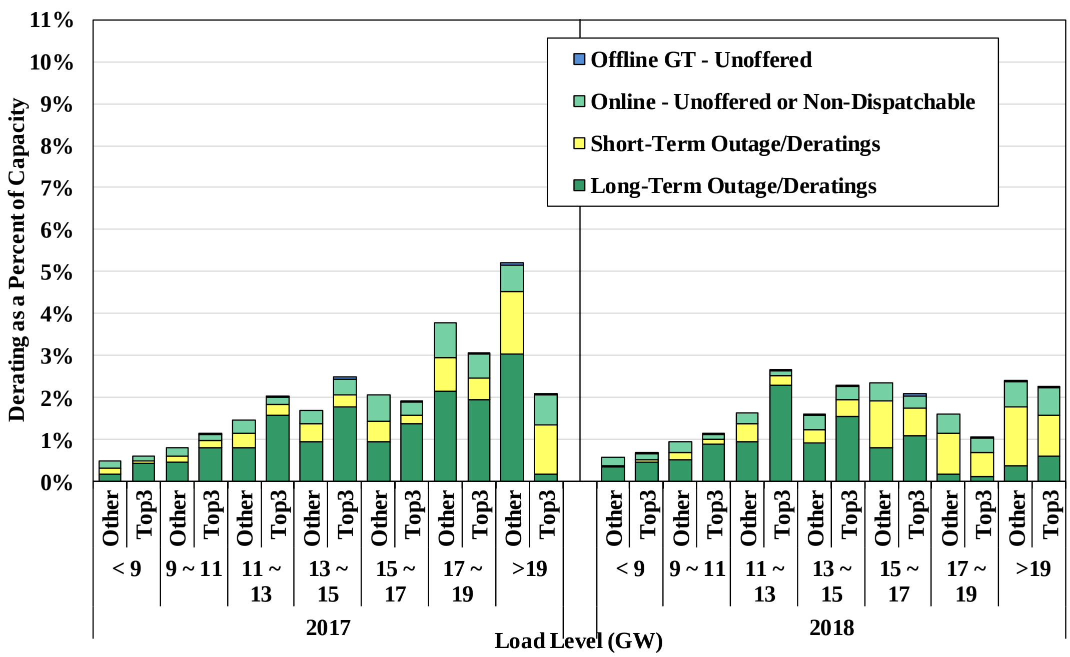


Figure A-24: Unoffered Economic Capacity by Supplier by Load Level in East New York
2017 – 2018



Key Observations: Unoffered Economic Capacity

- The general pattern of deratings was reasonably consistent with expectations for a competitive market in 2018.
    - Derated and unoffered economic capacity averaged 1.4 percent of total DMNC in NYCA, and 1.6 percent in Eastern New York in 2018, which was modestly higher than 2017 levels.
    - Derated and unoffered economic capacity was mostly attributable to long-term maintenance deratings (making up 55 percent of the total derated and unoffered economic capacity in NYCA and 63 percent in Eastern New York in 2018).
        - Most of this economic capacity on long-term maintenance was scheduled during shoulder months as would be expected.
        - The largest three suppliers in Eastern New York had only small totals of long-term outages during the highest load hours.
- Economic capacity on outage/deratings was marginally higher in the summer of 2018 than in the previous summer largely because of a few notable outages and deratings this summer.
    - In particular, forced derates and outages of a nuclear unit, and maintenance outages of several combined cycle unit in September contributed to higher unoffered economic capacity in the summer of 2018.
- In addition, higher demand levels and energy prices in 2018 resulted in more frequent conditions when the planned outages of low-cost units occurred when they would have been economic. This made them more likely to be flagged as uneconomic than was the case in 2017.
- Although long-term deratings are not likely to reflect withholding, inefficient long-term outage scheduling (i.e., to schedule an outage during a period that the capacity is likely economic for a significant portion of the time if the outage could be scheduled at a better time) raises significant efficiency concerns.
    - The NYISO can require a supplier to re-schedule a planned outage for reliability reasons, but the NYISO cannot require a supplier to re-schedule for economic reasons, and there are no mitigation measures that would address outage scheduling that is not consistent with competitive behavior. It would be beneficial for the NYISO to consider expanding its authority to reject outage requests that would take economic capacity out-of-service during relatively high load conditions. However, any such process would require significant resources for the NYISO to administer effectively.

- However, resources with low marginal costs may have few, if any, time periods when their capacity would not be economic. So, such resources will show up as derated economic capacity, regardless of when they take an outage.

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.[244, 245] An offer parameter is generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-25 to Figure A-28: 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 is otherwise economic at the market clearing price but for owner's elevated offer.[246] 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 lower thresholds: Lower Threshold 1 is 25 percent of a generator's reference level, and Lower Threshold 2 is 100 percent of a generator's reference level. The two lower thresholds are included to assess 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,

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244 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 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.

245 Due to the Fuel Cost Adjustment (FCA) functionality, a generator's reference level can now 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.

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

because there is uncertainty in the estimation of the marginal costs of individual units, results based on lower thresholds are more likely to flag behavior that is actually competitive.

Like the analysis of deratings in the prior subsection, it is useful to examine the output gap by load level and size of supplier because the incentive to economically withhold resources is positively correlated with these factors. Hence, these figures indicate how the output varies as load increases and whether the largest three suppliers exhibit substantially different conduct than other suppliers.

Figure A-25: Output Gap by Month in New York State
2017 – 2018

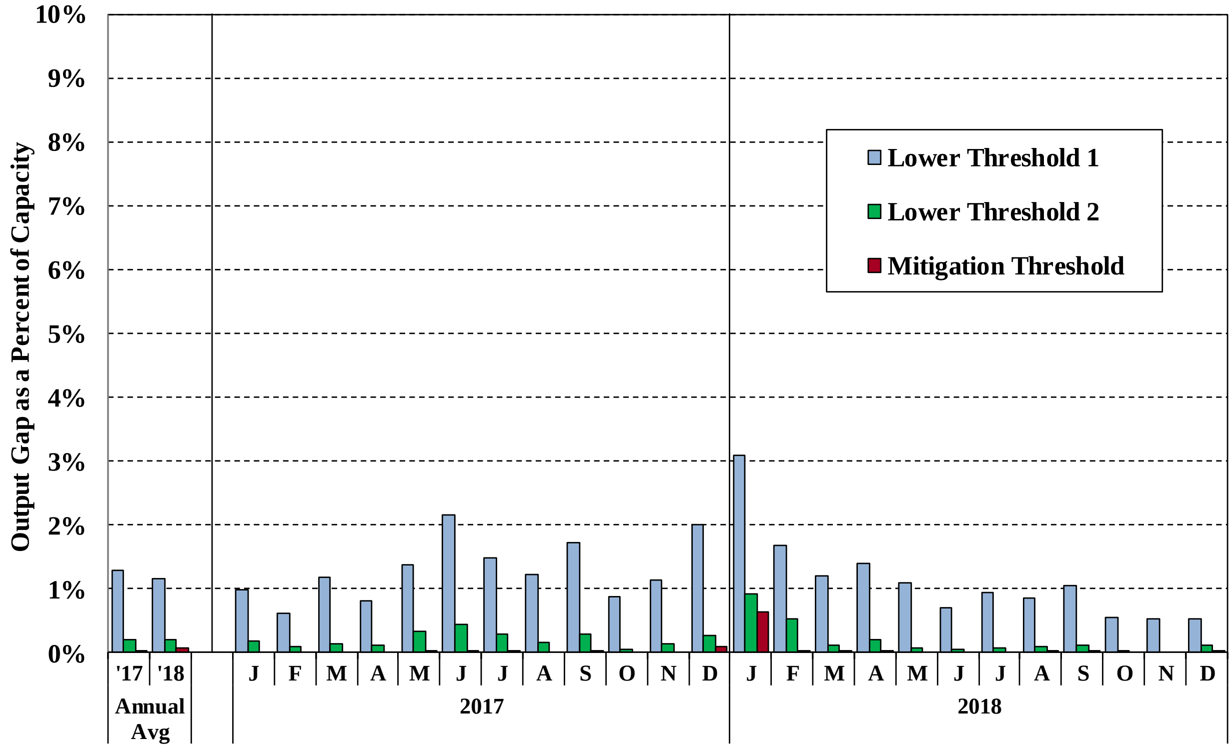


Figure A-26: Output Gap by Month in East New York
2017 - 2018

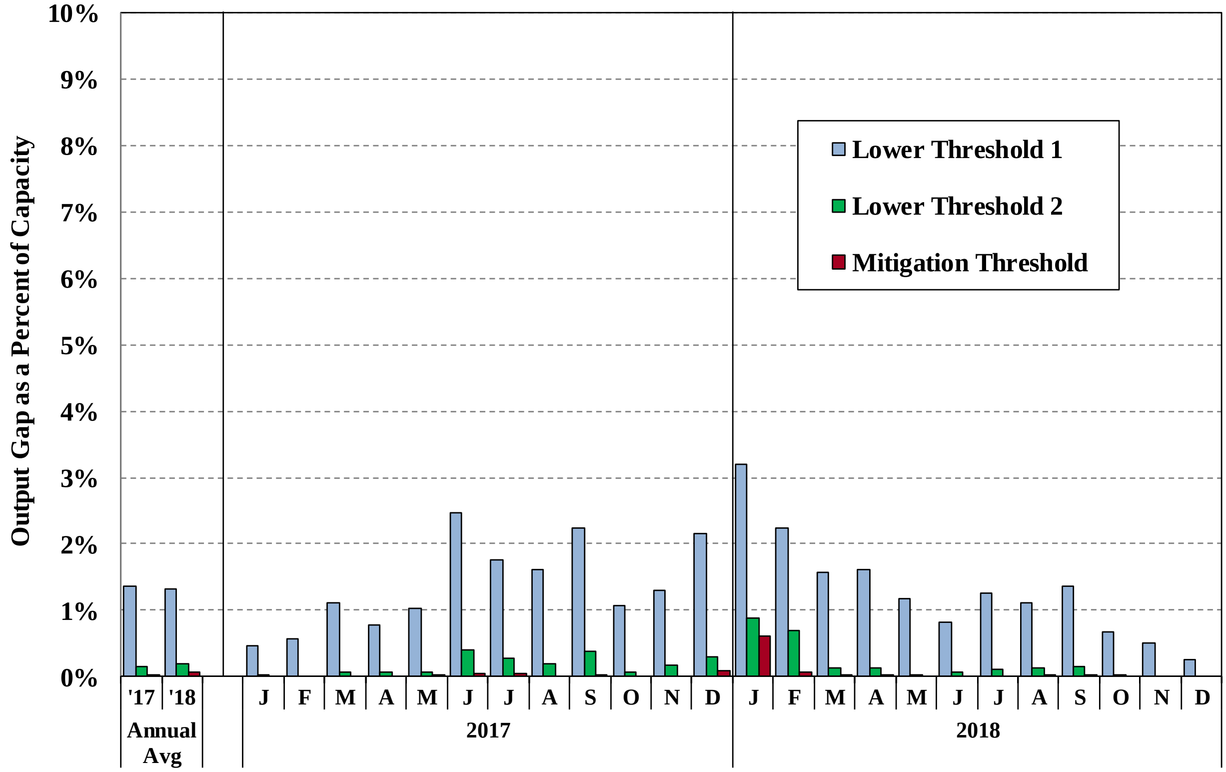


Figure A-27: Output Gap by Supplier by Load Level in New York State
2018

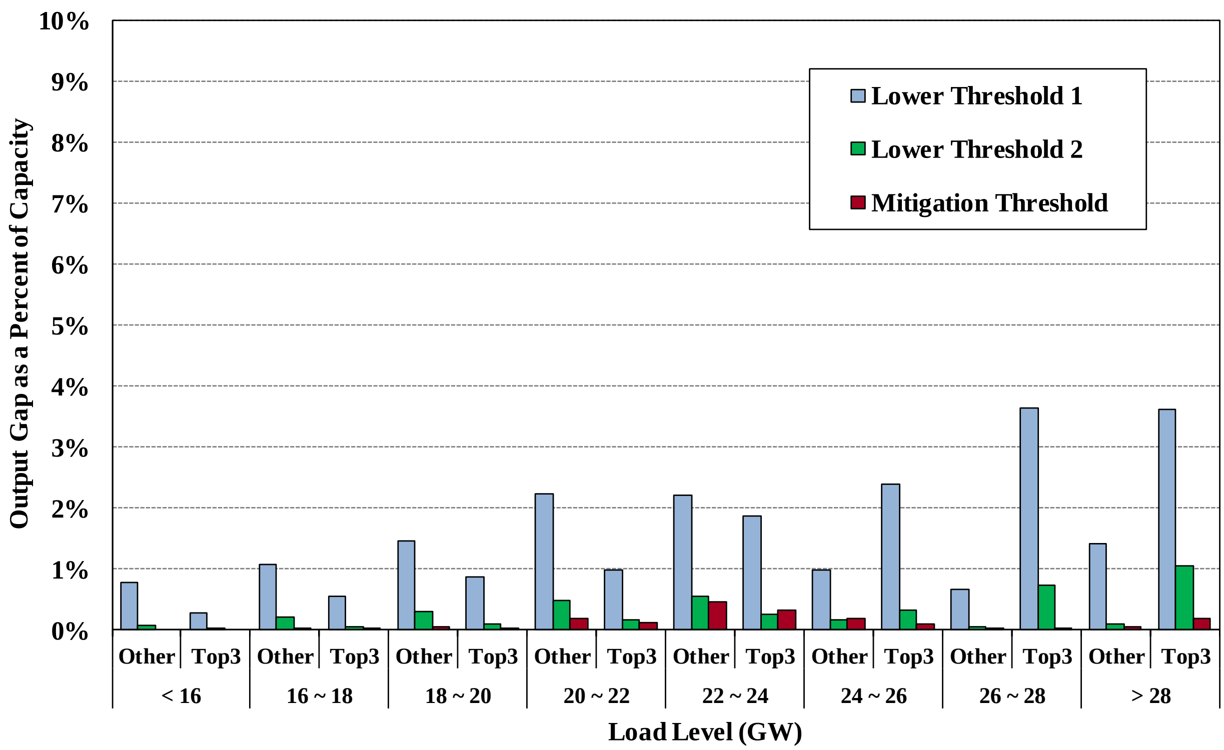
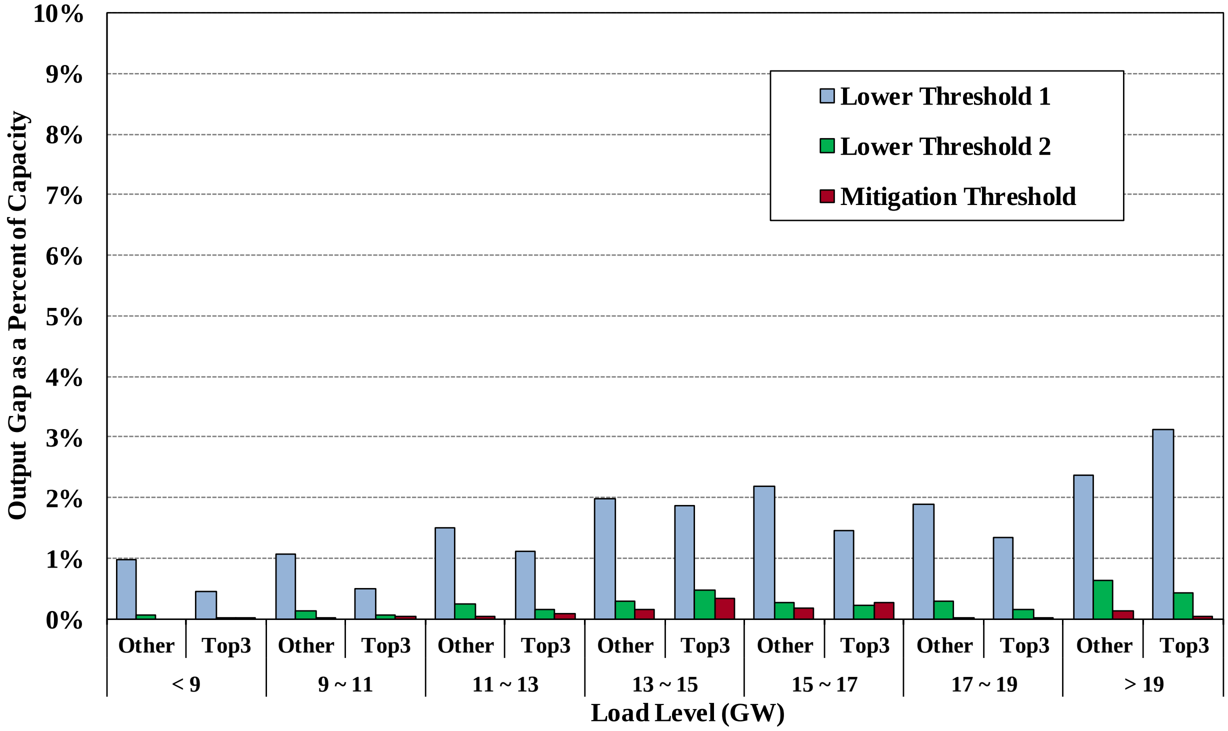


Figure A-28: Output Gap by Supplier by Load Level in East New York
2018



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged less than 0.1 percent of total capacity at the mitigation threshold and roughly 1.3 percent at the lowest threshold evaluated (i.e., 25 percent) in 2018 for NYCA.
- Output Gap was most largest during the coldest winter months (i.e., January). However, this does not raise significant concerns because the Output Gap appears to be driven by differences between the actual fuel costs faced by generators and the fuel index prices. These differences were primarily due to the following factors:
  - Volatility in gas markets can lead to large discrepancies between the published gas price index and actual fuel costs. This is further compounded by flow restrictions that are often placed on pipelines during cold weather events. Such restrictions limit the generators' intake of gas and could impose heavy penalties for failures to comply.[247]
  - Some portions of the generation supply stack consist of several baseload resources that compete for the same gas access. Thus, although market conditions may appear

[247] The NYISO Market Services Tariff in Attachment H does not allow for the use of unauthorized natural gas from generators. Thus, to comply with the hourly restrictions of an Hourly Operational Flow Order, some generators may be required to purchase up to the equivalent of 23 additional hours of gas plus 23 times the start gas to operate for a single hour during these events.

to be favorable for simultaneous dispatch of multiple resources, the Output Gap metric may under-represent the true gas costs these units would face.

- Overall, the output gap level in 2018 did not raise significant concerns about economic withholding.

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.[248] 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 preceding twelve-month period.[249] 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

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

249 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.

New York City.[250] 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.[251]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[252] 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.[253]
- 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 such a generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

To avoid being mitigated below cost, generators can reflect fuel cost increases in their reference levels by submitting Fuel Cost Adjustments ("FCAs"). However, the FCA functionality could provide the opportunity for a generator to submit unjustifiable FCAs, so we routinely review FCA submissions to ensure that inflated submissions do not lead clearing prices to be inflated above competitive levels.

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250 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.

251 See NYISO Market Services Tariff, Section 23.3.1.2.3.

252 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 unmitigation.

253 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. 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.

Figure A-29: Fuel Cost Adjustments During the Cold Spell

Figure A-29 summarizes our review of generator FCAs to reference levels during the cold spell from late-December 2017 through early-January 2018.[254] We monitor FCAs to ensure that generators do not use them to inappropriately inflate energy prices and avoid mitigation. The top portion of the chart shows natural gas costs in the day-ahead market in NYC.[255] The bottom portion of the chart shows the offer pattern in the day-ahead market for gas-capable units in NYC. Generator offers are classified as:

- Self-scheduled (including quantities offered in Self Flex and Self Fix modes, and quantities offered at a price less than $10/MWh);
- Estimated oil-based offers;
- Estimated gas-based offers without an FCA;
- High Startup Notification Times ("SUNTs");
- Offers with a gas FCA in the following ranges:
  - FCA ≤ 90% of index;
  - 90% of index ≤ FCA ≤ 110% of index;
  - 110% of index ≤ FCA ≤ 150% of index; and
  - FCA > 150% of index.

254 The Fuel Cost Adjustment mechanisms outlined in Attachment H of the NYISO Market Services Tariff allow generators to submit different fuel prices than the index value when system conditions suggest more than typical levels of fuel price volatility. Additionally, generators may request to switch to an alternate fuel through this mechanism when the secondary fuel is expected to be more economic than the primary fuel, or if a physical constraint restricts availability of the more economic primary fuel.

255 The natural gas cost is based on the Transco Zone 6 (NY) index price and includes a $0.2 transportation charge and a 6.9 percent tax rate.

Figure A-29: Fuel Cost Adjustments During the Cold Spell

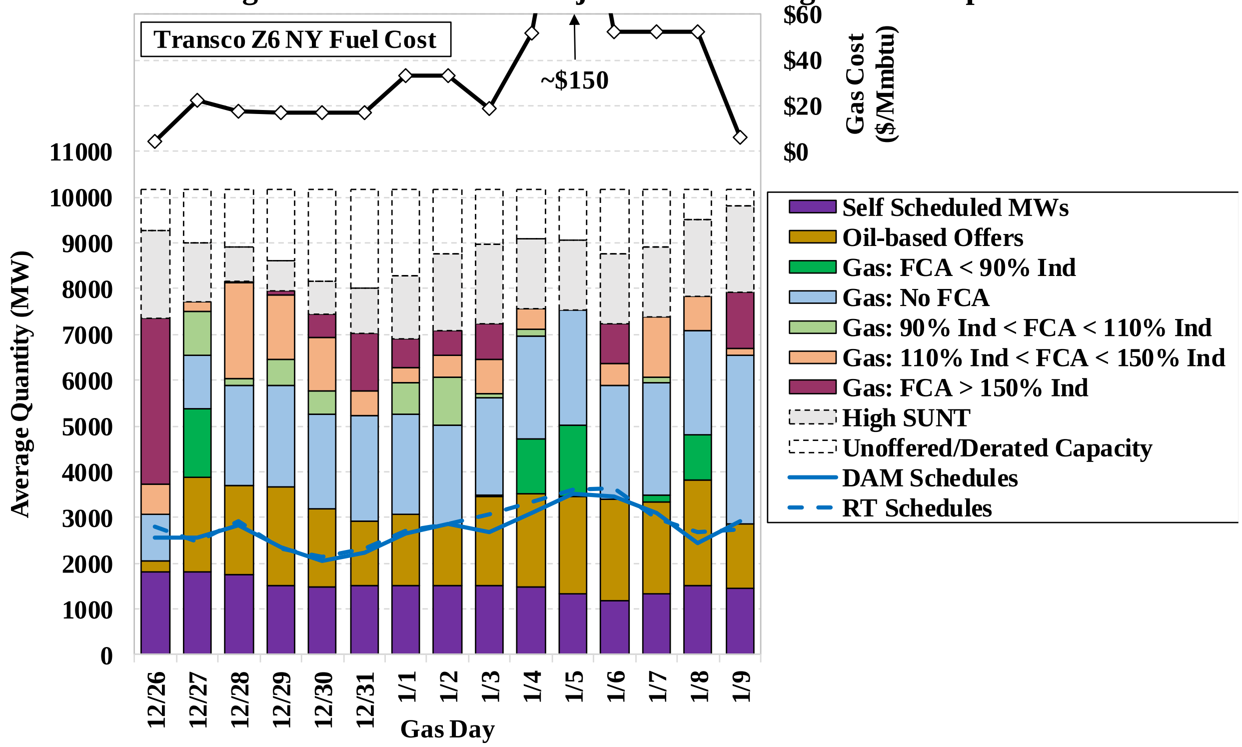


Figure A-30 & Figure A-31: Summary of Day-Ahead and Real-Time Mitigation

Figure A-30 and Figure A-31 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2017 and 2018. 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).[256] 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.

256 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-30: Summary of Day-Ahead Mitigation
2017 – 2018

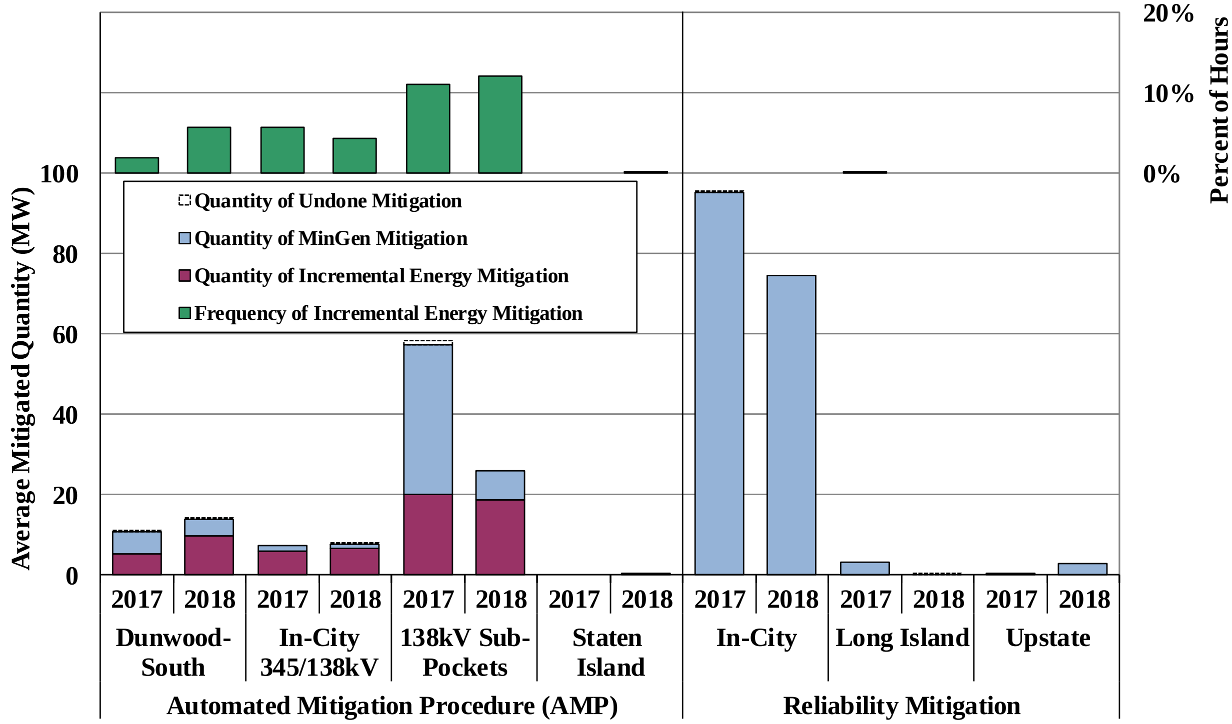
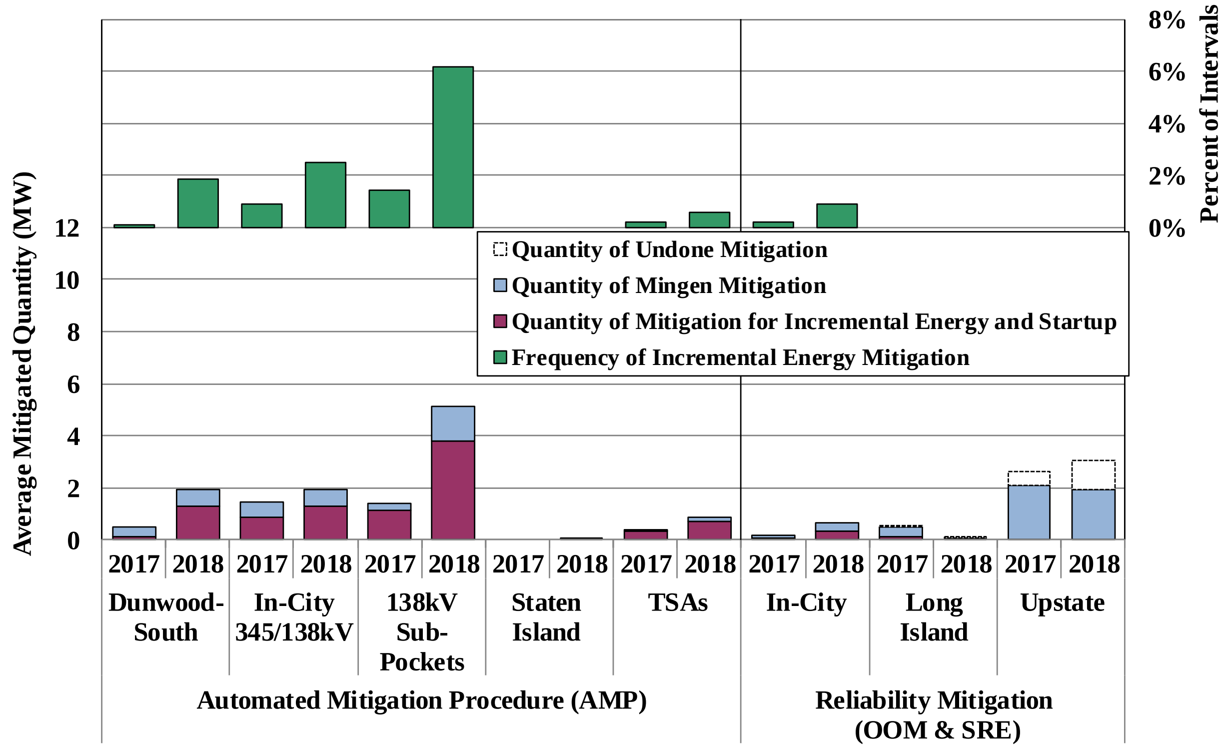


Figure A-31: Summary of Real-Time Mitigation
2017 – 2018



Key Observations: Day-ahead and Real-time Mitigation

- Most mitigation occurs in the day-ahead market, since this is where most supply is scheduled. Day-ahead mitigation fell from 2017.
  - Local reliability (i.e., DARU and LRR) mitigation in New York City (which accounted for 62 percent of day-ahead mitigation) fell modestly because a larger share of the reliability commitments were of steam units (as opposed to 2017 when more of the reliability commitments were of combined cycle units)
    - Steam units tend to have high upper operating limits but low minimum generation level. Hence, although more total capacity was committed for reliability, NYISO mitigated less minimum generation output (see Section V.I in the Appendix).
    - These mitigations limited guarantee payment uplift but did not affect LBMPs.
  - AMP mitigation accounted for 38 percent of day-ahead mitigation, which was also down from 2017 levels.
    - Reduced minimum generation mitigation in the 138kV load pockets was the primary driver of this decline.
    - This was a result of some generators modifying their bidding behavior in a manner that was more consistent with their reference levels in 2018.
- For the gas days during the cold spell from December 27 to January 8, an average of 1.9 GW (or 18 percent) of NYC generating capacity submitted fuel cost adjustments for gas before the day-ahead market. Of these FCAs, an average of:
  - 770 MW was submitted between 110 and 150 percent of the index; and
  - 360 MW was submitted that was more than 150 percent of the index.
  - The wide variation in FCAs reflects the relative inelasticity of natural gas supply under scarcity conditions driven by cold weather. Under such conditions, increased gas consumption by NYC generators would lead to steep increases in gas prices, so many generators to switch to using fuel oil.
- While some fuel cost adjustments did not appear to be reasonable, the LBMP impact was small because imports, oil-fired generation, and self-scheduled generation were generally sufficient to satisfy demand.
- Large deviations between submitted fuel costs and published index costs normally occurred when gas prices were changing rapidly from one day to the next, reflecting the volatility of gas prices and associated risk factors.
  - However, a significant under-adjustment (relative to index) occurred on January 5 because the index cost approached $150 per MMbtu while the adjustment was limited by the software to no more than $100 per MMbtu. Restricting legitimate adjustments is harmful, so we encourage NYISO to provide additional flexibility in the software.

D. Ancillary Services 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. The 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.

The ancillary services markets also include ancillary services demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be satisfied at a cost of less than the demand curve, the system is in a shortage and the reserve demand curve value will be included in both 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 examining ancillary services offer patterns in the day-ahead market. 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-32 to Figure A-36: Summary of Day-ahead Ancillary Services Offers

The following five figures compare the ancillary services offers for generators in the day-ahead market for 2017 and 2018 on a monthly basis as well as on an annual basis.[257] The quantities offered are shown for the following categories:[258]

- 10-minute spinning reserves in Western New York,
- 10-minute spinning reserves in Eastern New York,
- 10-minute non-spinning reserves in Eastern New York,
- 30-minute operating reserves in NYCA,[259] and

257 These figures do not include several demand resources that are eligible for providing 10-minute spinning reserves and have a total capability of roughly 110 MW.

258 The quantity of 10-minute non-spinning reserve offers in Western New York is very small and is not reported here.

259 This category only includes the reserve capacity that can be used to satisfy the 30-minute reserve requirements but not the 10-minute reserve requirements. That is, the reported quantity in this chart excludes the 10-minute spinning and 10-minute non-spin reserves from the total 30-minute reserve capability.

- Regulation.

Offer quantities are shown according to offer price level for each category. This evaluation summarizes offers for the five ancillary services products from all hours and all resources.

Figure A-32: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2017-2018

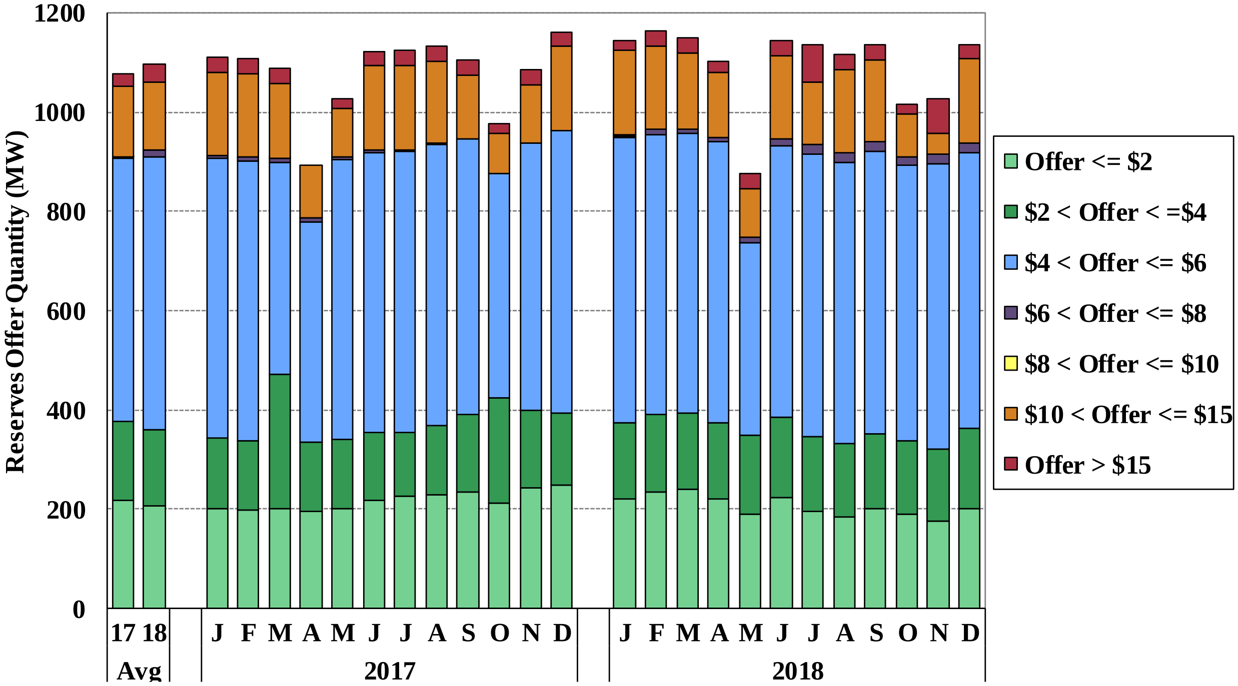


Figure A-33: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2017-2018

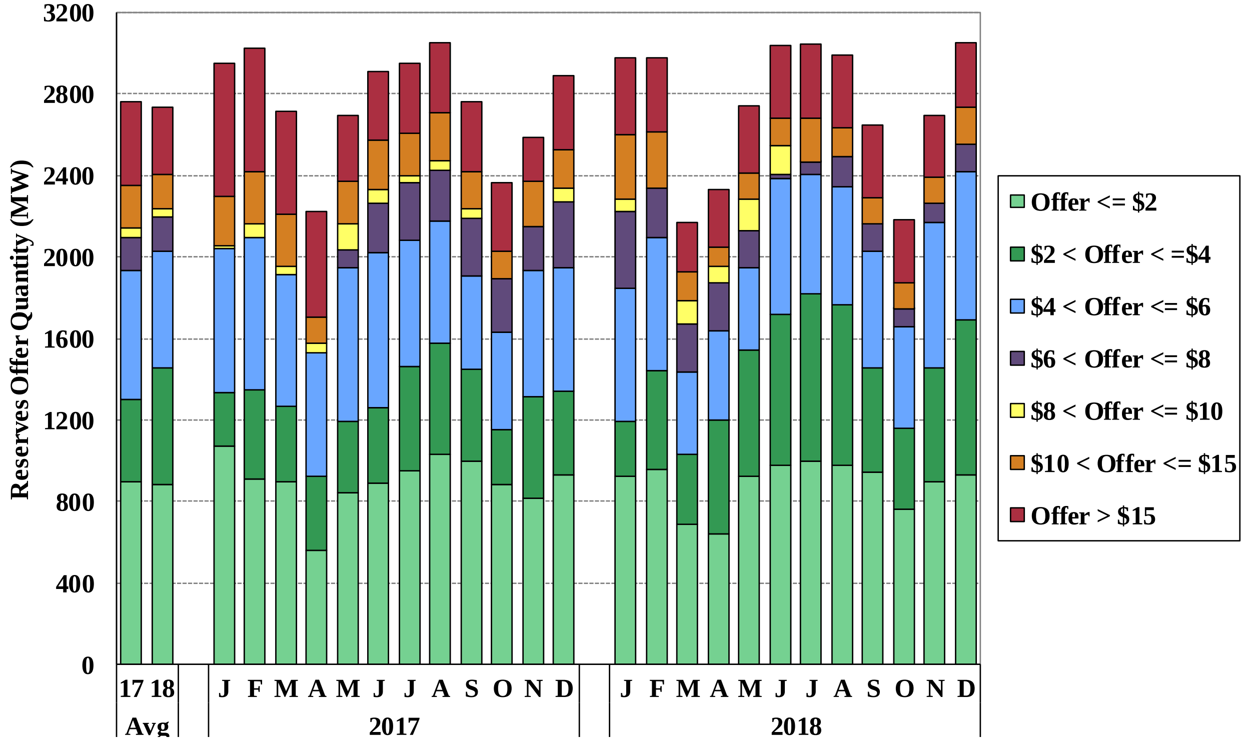


Figure A-34: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2017-2018

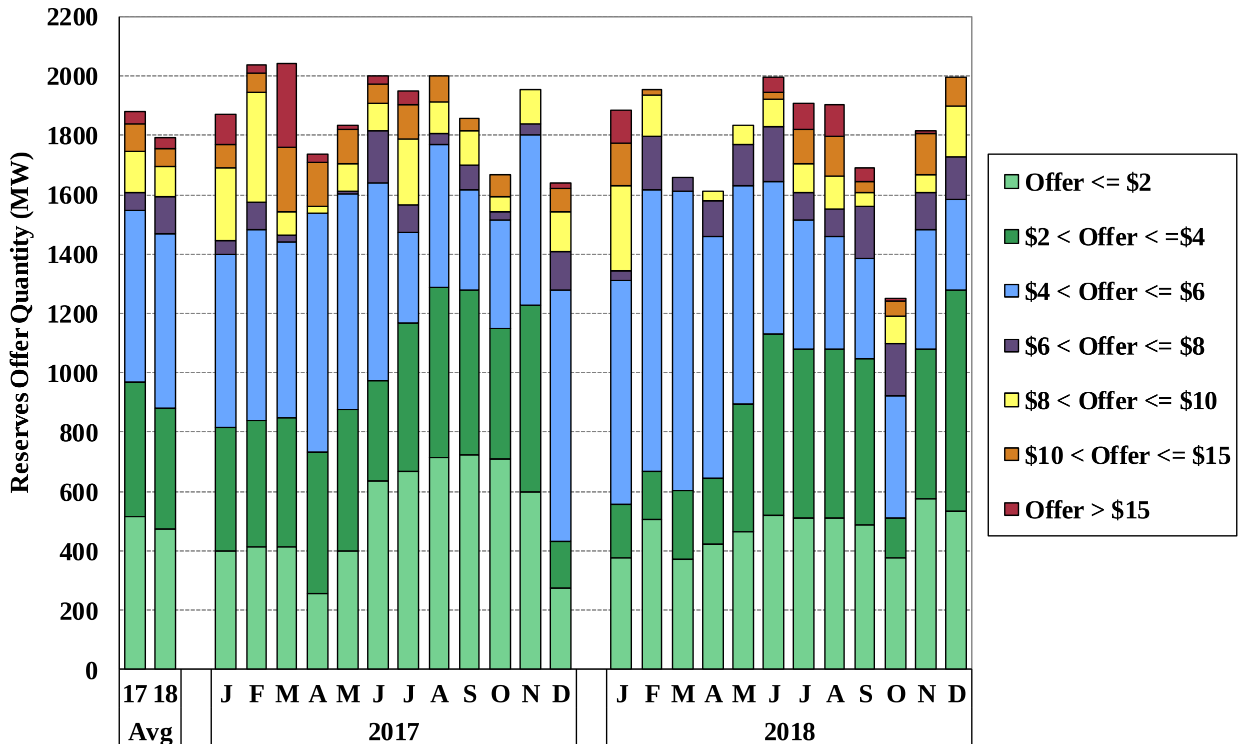


Figure A-35: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2017-2018

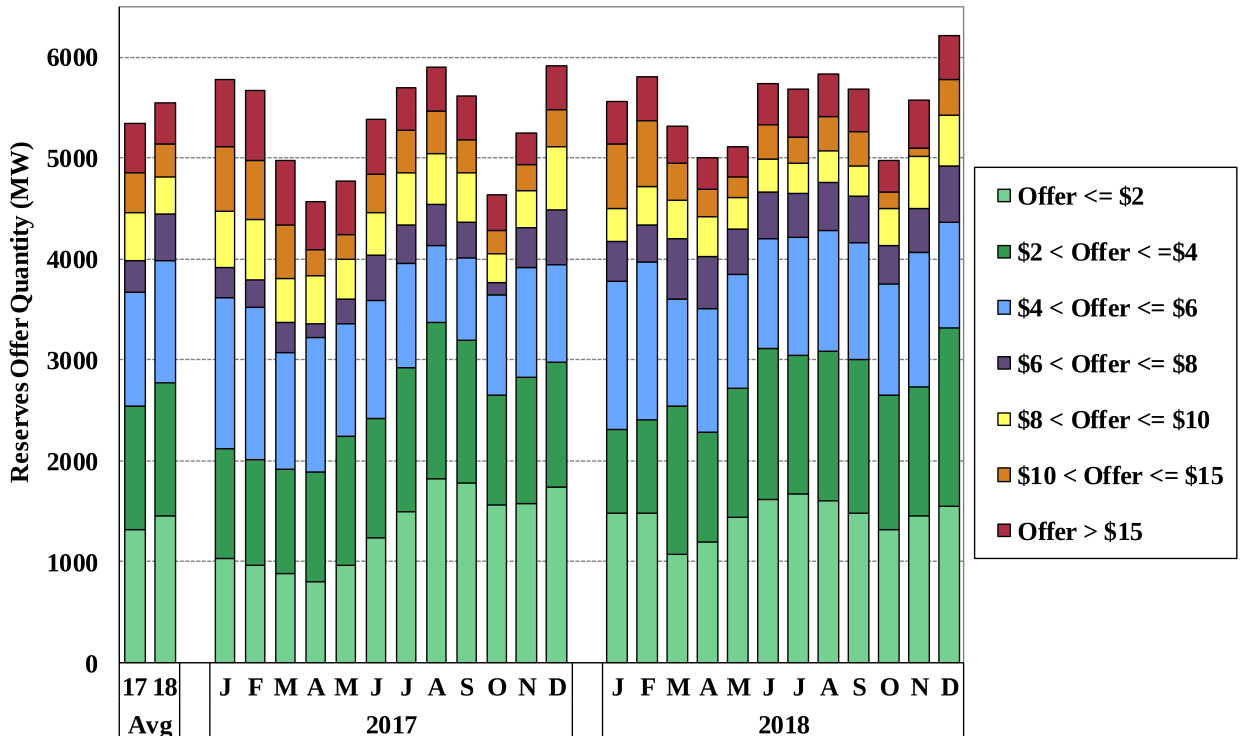


Figure A-36: Summary of Regulation Capacity Offers
Day-Ahead Market, 2017-2018

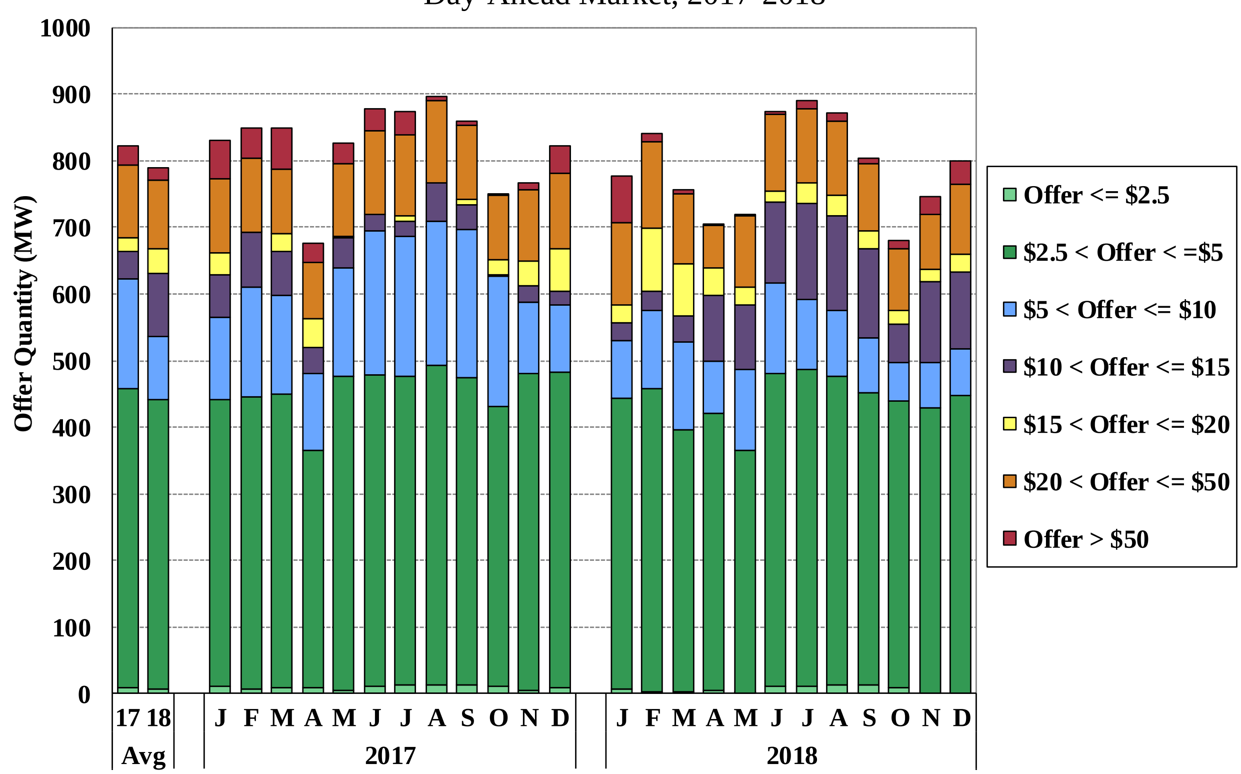


Figure A-37: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

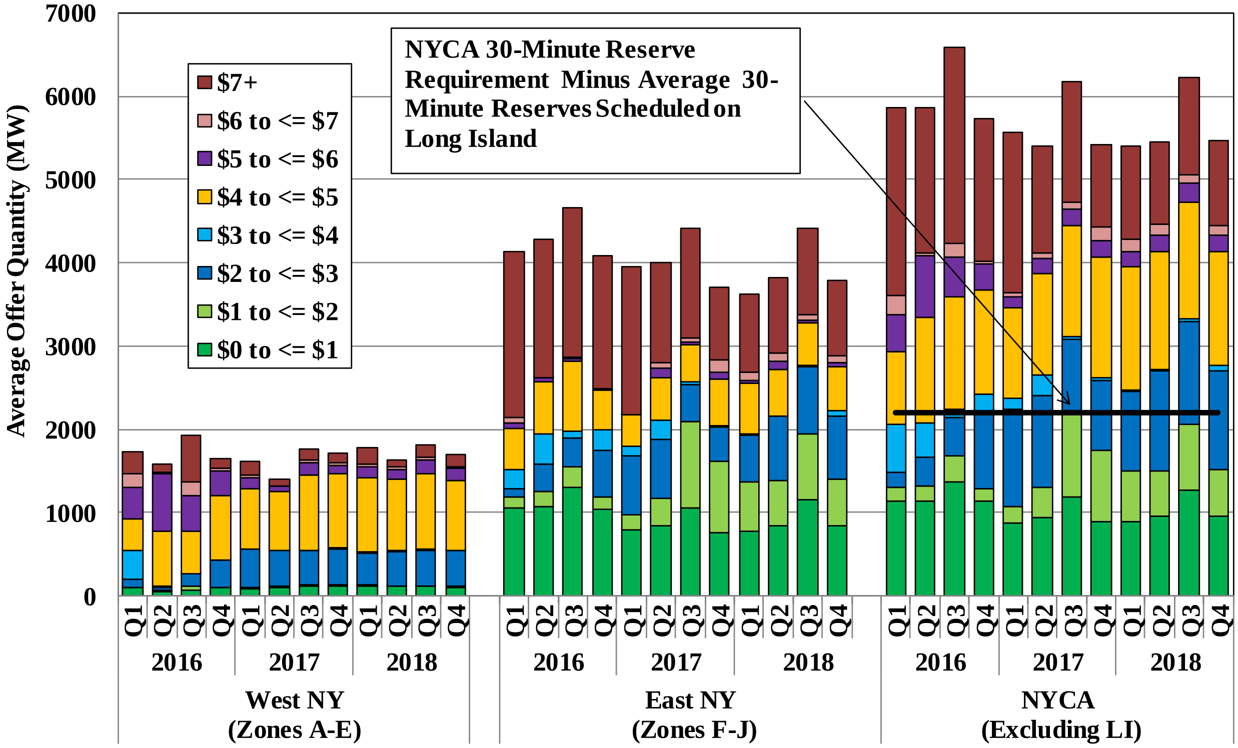
Figure A-37 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2016 to 2018. These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers, although they are not shown separately in the figure. Only offers from 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 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-37: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement

Committed and Available Offline Quick-Start Resources, 2016-2018



Key Observations: Ancillary Services Offers

- The overall quantity of ancillary services offered in each of the five categories did not change significantly from 2017 to 2018.

  - The day-ahead offer quantities for all reserve products show a typical seasonal pattern, with planned outages leading to considerably lower quantities offered in the spring and fall than in the summer and winter.
  - East 10-minute non-spinning supply fell about 5 percent from 2017 to 2018 as the amount of capacity from new entrants in 2018 was smaller than the amount of capacity that exited the market via retirement, mothball, or IIFO.[260]
  - In the shoulder month of October, the amount of east 10-minute non-spinning reserves offers was significantly lower in 2018 than 2017, primarily because of generator outages.
  - The 30-minute operating reserve offer prices fell slightly from 2017 to 2018. However, the day-ahead clearing prices rose modestly over the same period reflecting higher opportunity costs to provide reserves services (see Figure A-11).

- We have reviewed day-ahead reserve offers and found many units that may be offering above the standard competitive benchmark (i.e., estimated marginal cost). However, the marginal cost of providing reserves in the day-ahead market is difficult to quantify.
  - We will continue to monitor day-ahead reserve offer patterns and consider additional rule changes including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the market power mitigation measures.
- Although the overall quantity of regulation offers from all resources was similar between 2017 and 2018, a few generators increased bids from the $5-$10 per MWh range in 2017 to the $10-$15 per MWh range in 2018. During years with higher load and fuel prices, the opportunity cost of moving up or down in real time tends to increase.[261]

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).

260 New entrants included new units and existing generators that expanded participation in the reserves product in 2018.

261 Above average load conditions tend to result in more units being committed which can increase the surplus regulation capacity which could offset the upward price pressure from higher bids.

- *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.[262]

- *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 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-38 to Figure A-45: 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.

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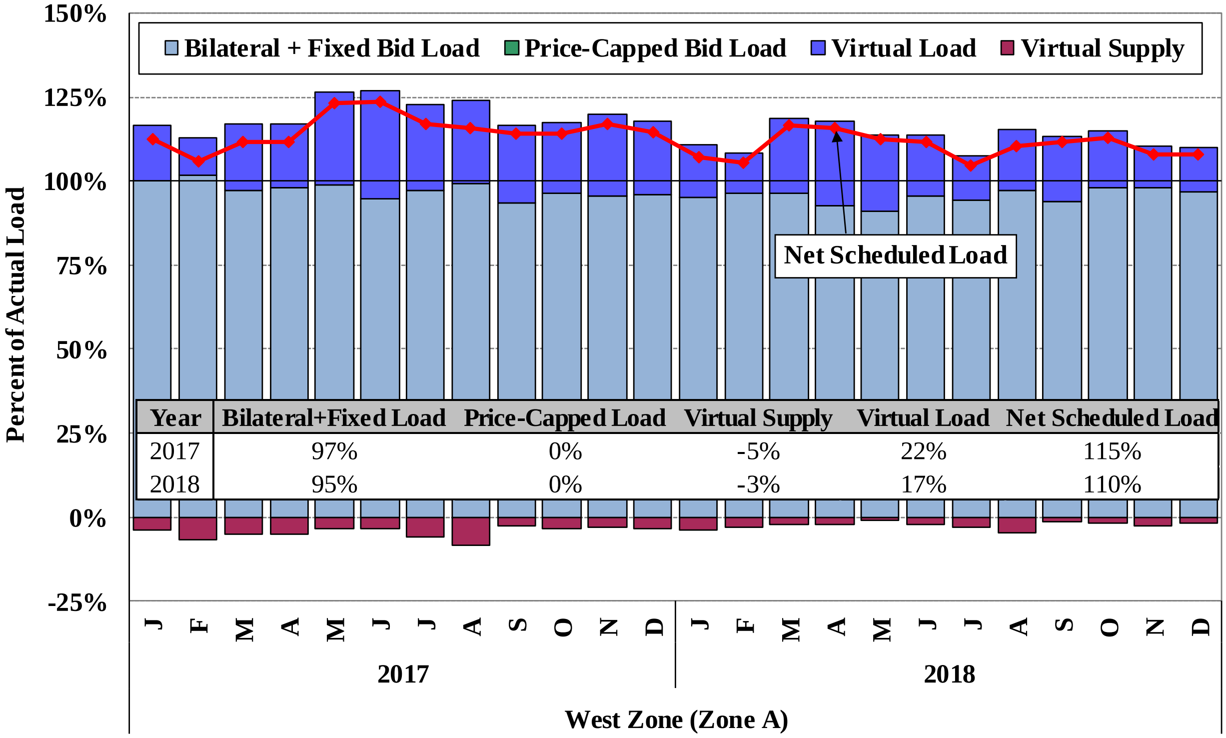
262 For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2017 and in 2018 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 2017 to 2018. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

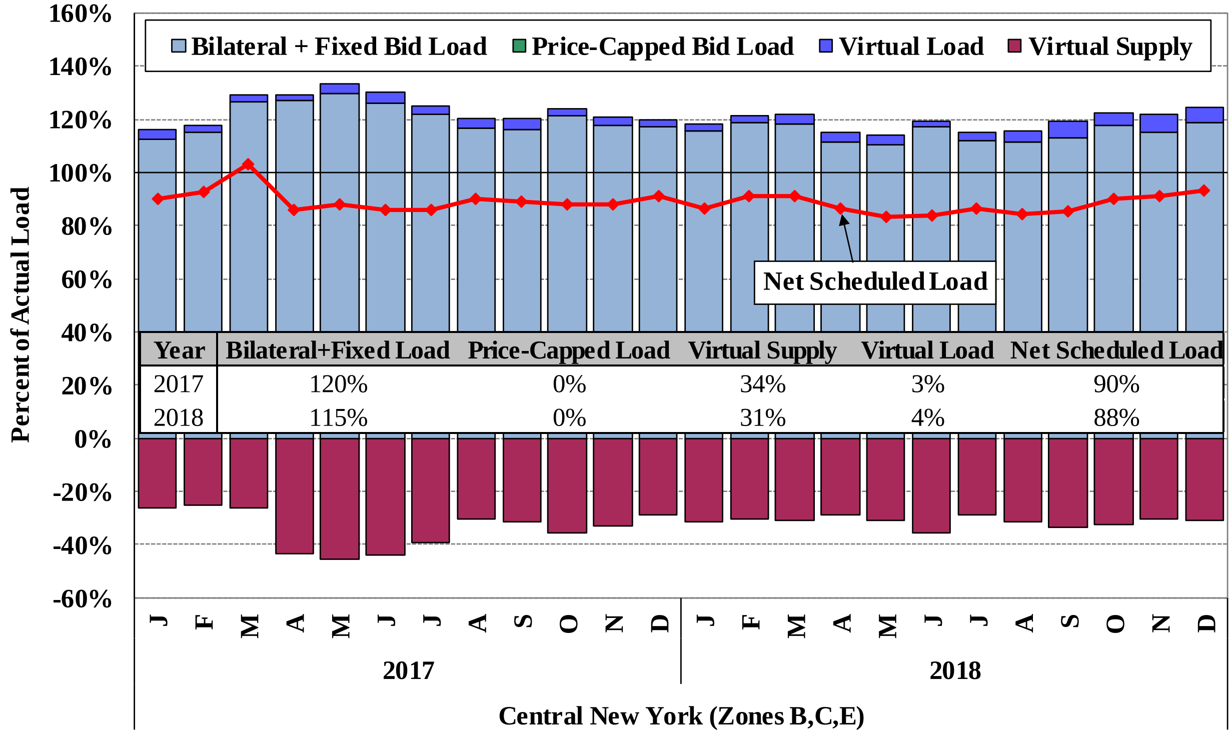
Figure A-38: Day-Ahead Load Schedules versus Actual Load in West Zone

Zone A, 2017 – 2018



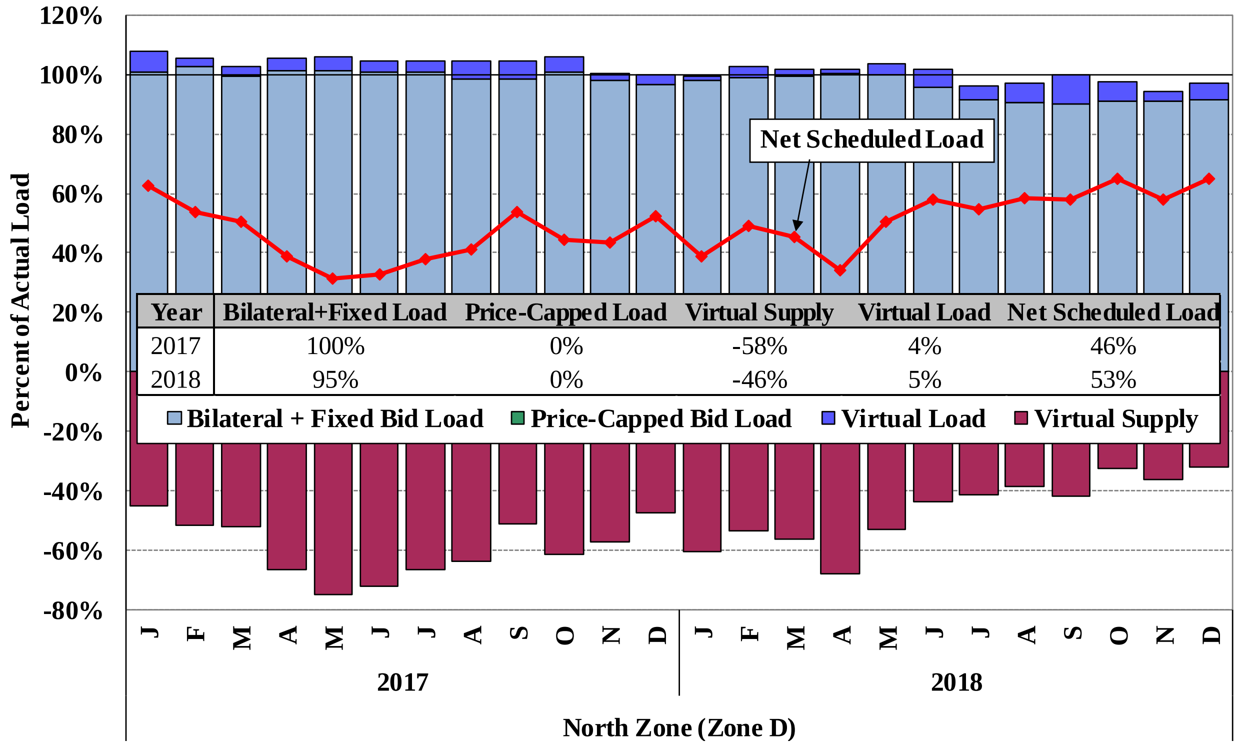
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	97%	0%	-5%	22%	115%
2018	95%	0%	-3%	17%	110%

Figure A-39: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2017 – 2018



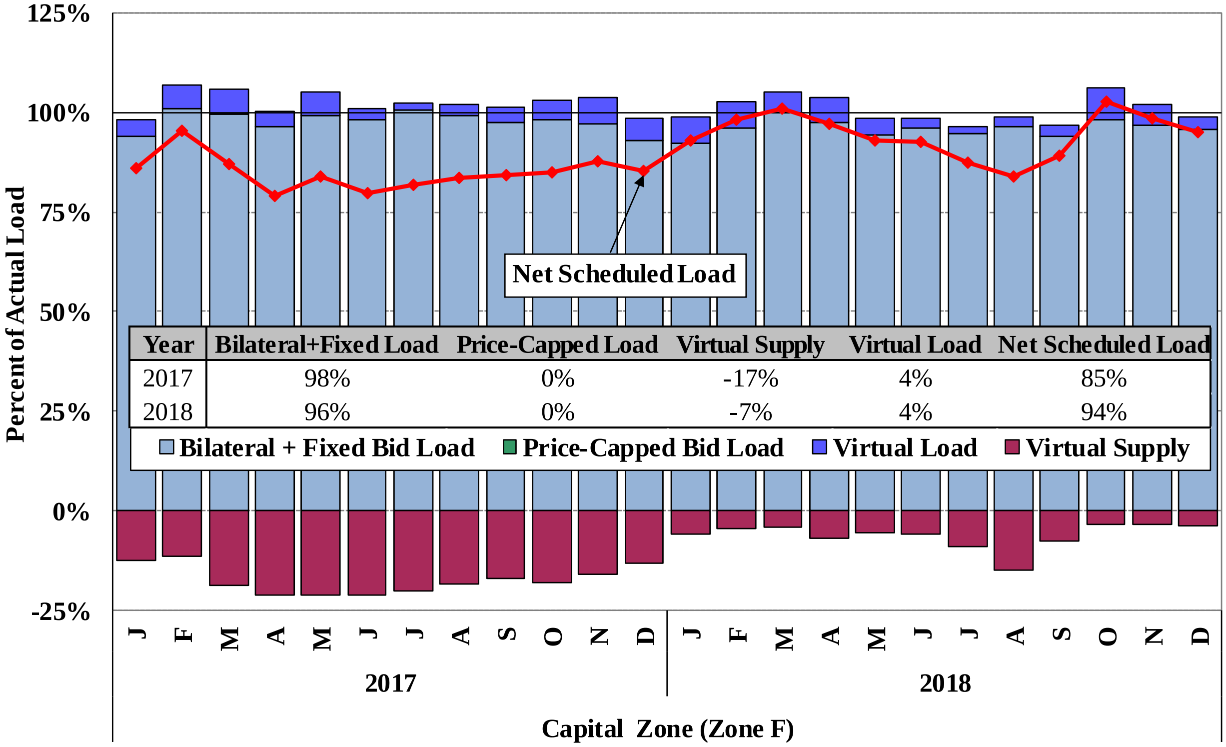
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	120%	0%	34%	3%	90%
2018	115%	0%	31%	4%	88%

Figure A-40: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2017 – 2018



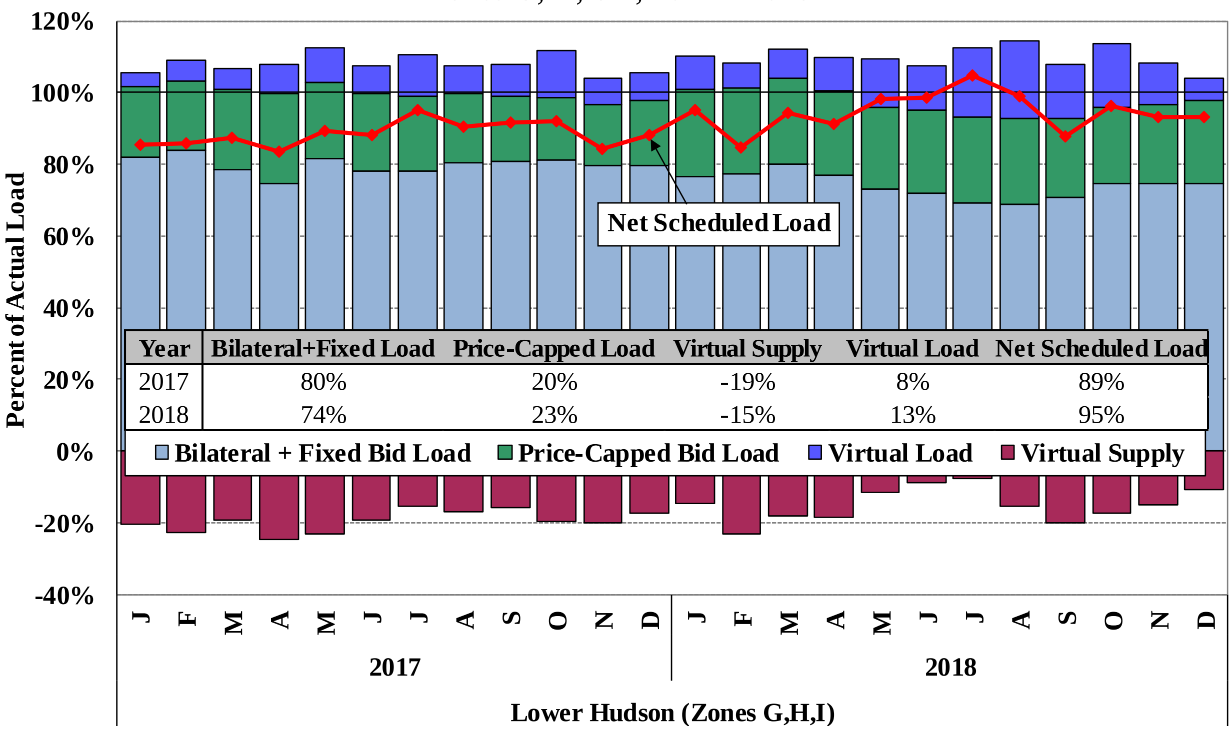
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	100%	0%	-58%	4%	46%
2018	95%	0%	-46%	5%	53%

Figure A-41: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2017 – 2018



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	98%	0%	-17%	4%	85%
2018	96%	0%	-7%	4%	94%

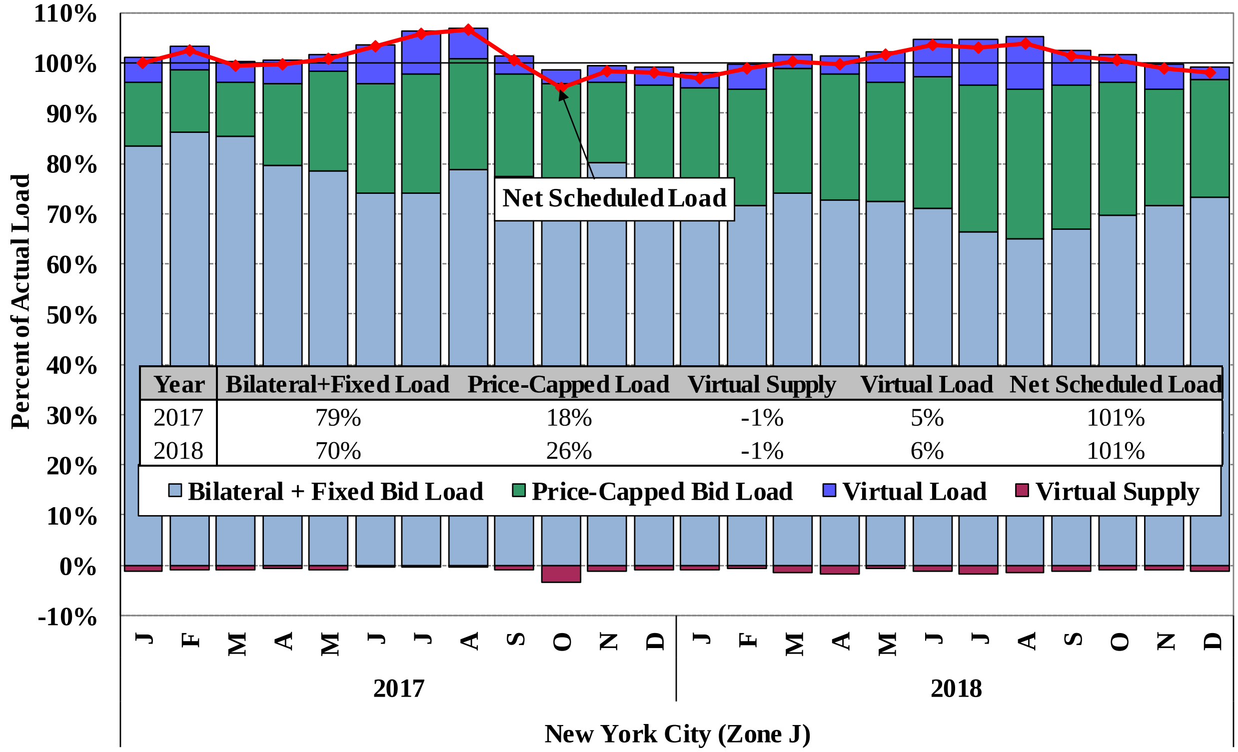
Figure A-42: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2017 – 2018



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	80%	20%	-19%	8%	89%
2018	74%	23%	-15%	13%	95%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in New York City

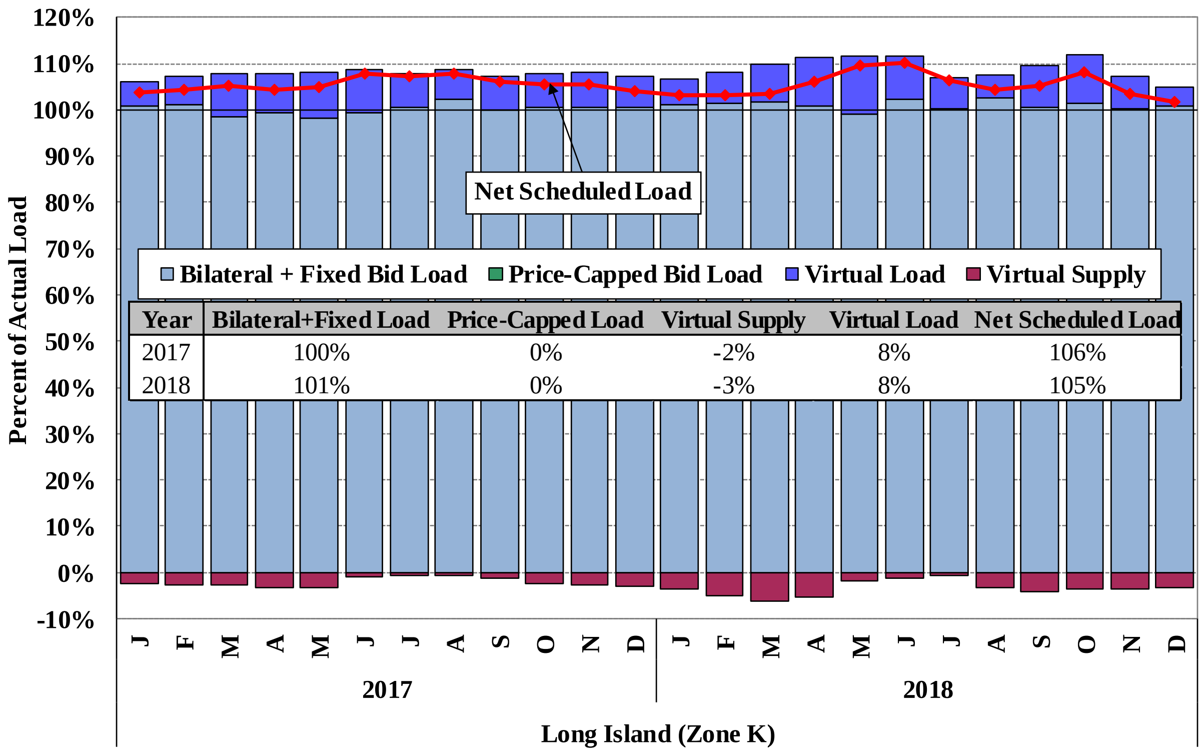
Zone J, 2017 – 2018



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	79%	18%	-1%	5%	101%
2018	70%	26%	-1%	6%	101%

Figure A-44: Day-Ahead Load Schedules versus Actual Load in Long Island

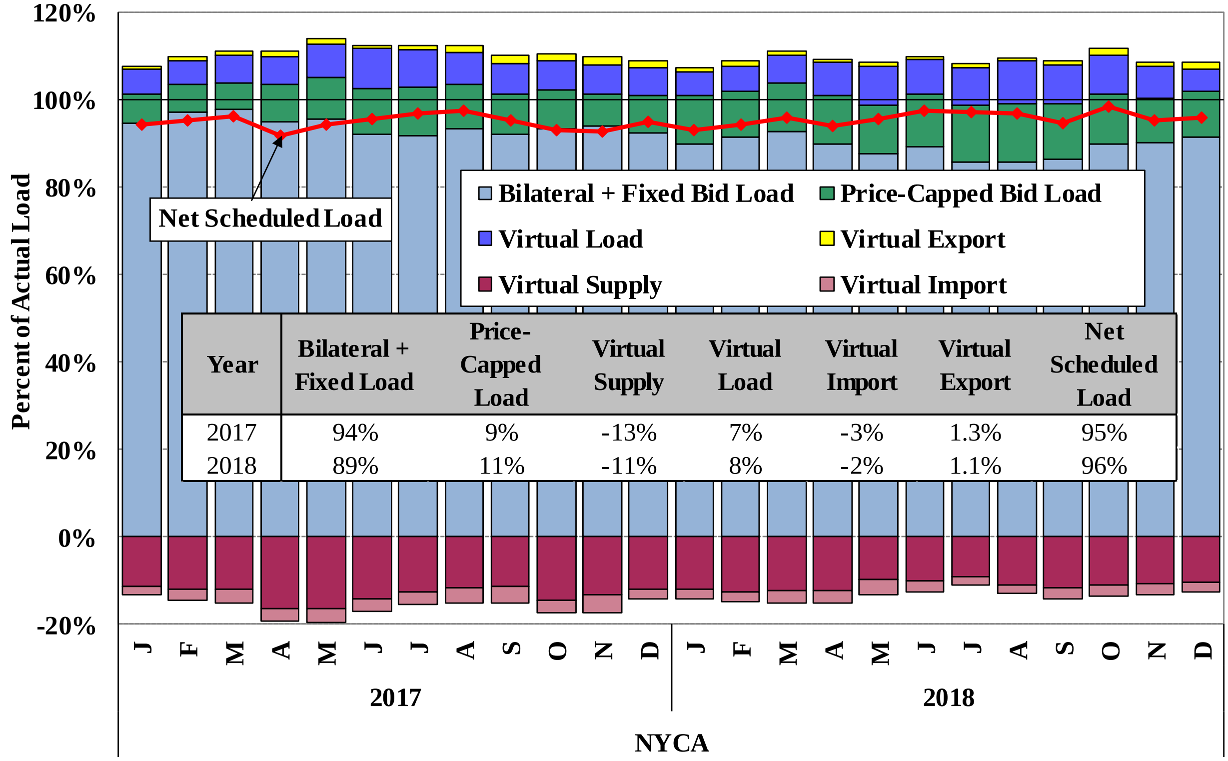
Zone K, 2017 – 2018



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2017	100%	0%	-2%	8%	106%
2018	101%	0%	-3%	8%	105%

Figure A-45: Day-Ahead Load Schedules versus Actual Load in NYCA

2017 – 2018



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2017	94%	9%	-13%	7%	-3%	1.3%	95%
2018	89%	11%	-11%	8%	-2%	1.1%	96%

Key Observations: Day-ahead Load Scheduling

- For NYCA, roughly 96 percent of actual load was scheduled in the day-ahead market (including virtual imports and exports) during peak load hours in 2018, similar to 2017.
- The 2018 scheduling patterns in most sub-regions were generally consistent with the 2017 patterns, but net load scheduling levels varied noticeably in some regions:
  - Over-scheduling in the West Zone has fallen steadily in recent years as a result of less volatile real-time congestion because of market enhancements and transmission upgrades. The NYISO incorporated some 115 kV West Zone constraints in the market software in December 2018, which further helped make efficient commitment in the day-ahead market and reduce the difference between day-ahead and real-time markets in this region.
  - Net load scheduling in the North Zone increased modestly from 2017 to 2018 as a result of deceased virtual supply that reflected frequent real-time price premiums in the North Zone in 2018 (8 months exhibited an average real-time premium in 2018).
  - Net load scheduling rose in the Lower Hudson Valley region because more virtual load was scheduled in the summer months as market participants anticipated increased congestion in this region that resulted from higher load levels and more frequent peaking conditions.

  - Net load scheduling in the Capital Zone rose in 2018 when a market participant substantially reduced its virtual supply offer quantity.

- The patterns of virtual trading and load scheduling were similar. Net load scheduling (including net virtual load) tend to be higher in locations where high real-time prices frequently result from volatile congestion.

  - This has led to a seasonal pattern in some regions. For example:

    - Net load scheduling in New York City increased in the summer months when acute real-time congestion into Southeast New York was more prevalent.

  - This has also resulted in locational differences between regions.

    - Average net load scheduling was generally higher in New York City, Long Island, and the West Zone than the rest of New York because congestion was typically more prevalent in these areas.

- Under-scheduling was still prevalent in West Upstate outside the West Zone.

  - This is generally consistent with the tendency for renewable generators to increase real-time output above their day-ahead schedules.

  - Load was typically under-scheduled in the North Zone by a large margin because large amounts of virtual supply are often scheduled here. This is an efficient response to the scheduling patterns of wind resources in the zone and imports from Canada, which typically rose in real-time above their day-ahead schedules.

F. Virtual Trading in New York

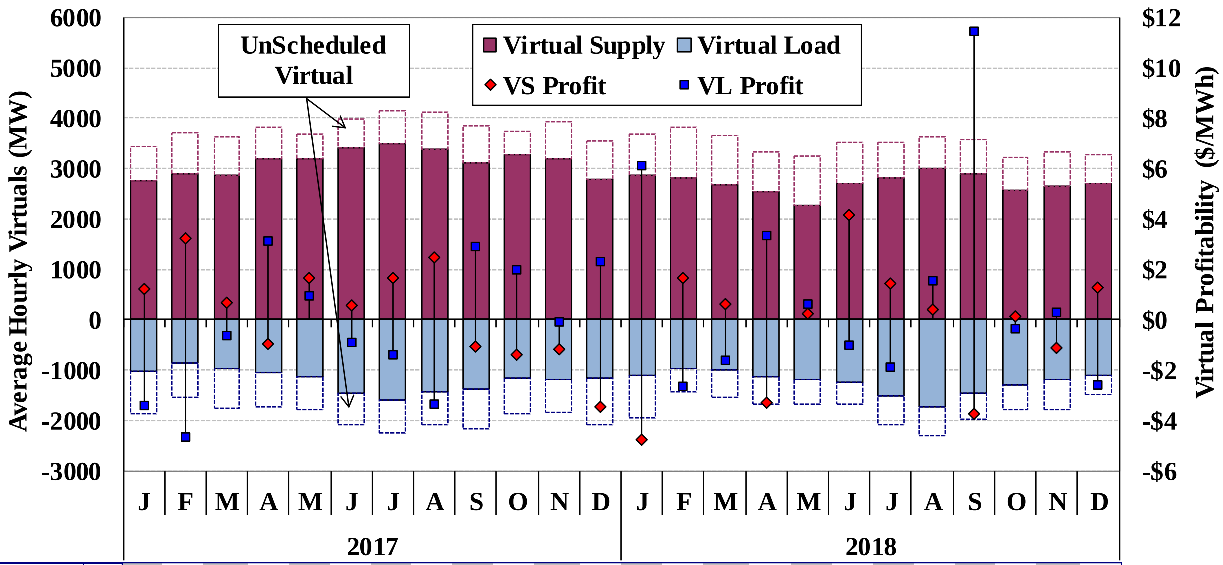
Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual bids and offers provide liquidity to the day-ahead market 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-46: 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 2017 and 2018. 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.[263,264]

Figure A-46: Virtual Trading Volumes and Profitability
2017 – 2018



		2017 J	F	M	A	M	J	J	A	S	O	N	D	2018 J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	243	507	585	449	645	502	593	435	257	271	320	396	373	450	419	376	475	620	320	299	437	366	312	326
	%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%	10%	14%	16%	7%	6%	10%	9%	8%	9%
Loss > 50% of Avg. Zone Price	MW	284	336	514	454	553	542	568	465	418	399	412	478	442	342	401	466	537	531	329	328	428	430	345	317
	%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%	13%	16%	14%	8%	7%	10%	11%	9%	8%

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

264 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.

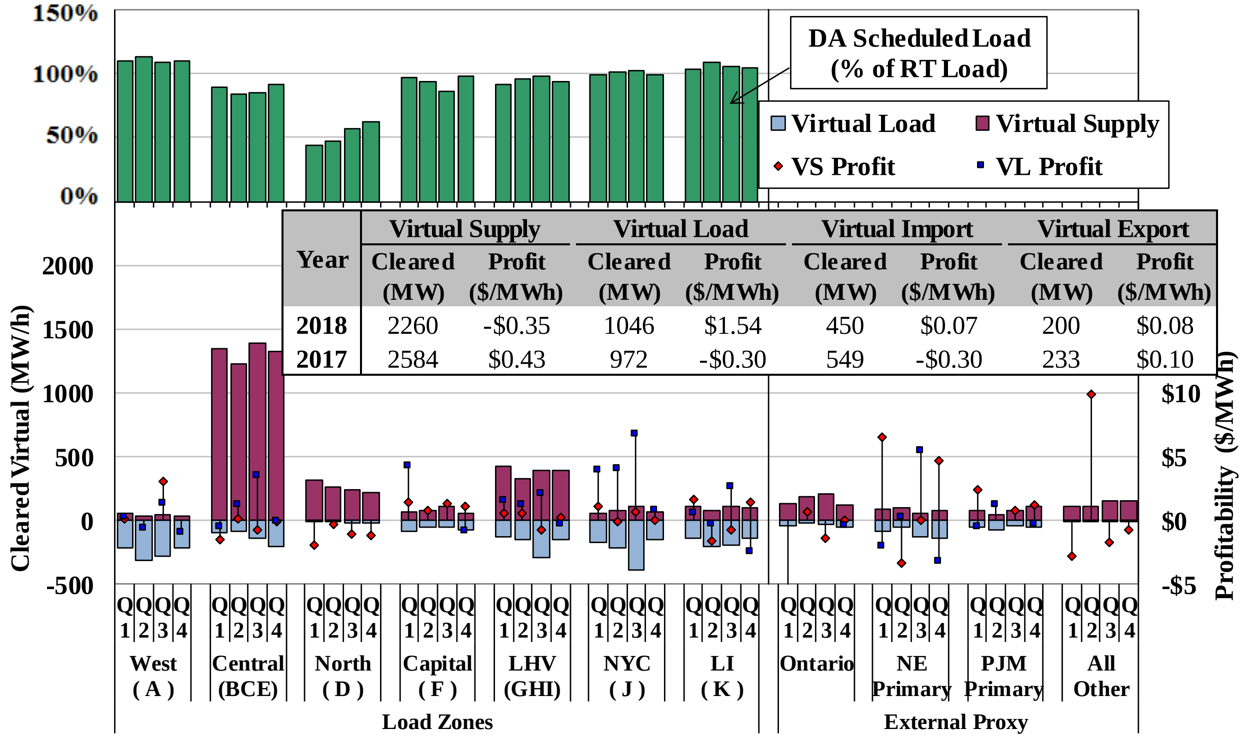
The table below the figure shows a screen for relatively large profits or losses, which identifies virtual transactions with gross profits (or losses) larger than 50 percent of the average zone (or proxy bus) price. For example, an average of 326 MW of virtual transactions (or 10 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2018. Large profits may be an indicator of a modeling inconsistency, while sustained losses may be an indicator of potential manipulation of the day-ahead market.

Figure A-47: Virtual Trading Activity

Figure A-47 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 2018. 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 2017 and 2018.

Figure A-47: Virtual Trading Activity [265]
by Region by Quarter, 2018



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)
2018	2260	-$0.35	1046	$1.54	450	$0.07	200	$0.08
2017	2584	$0.43	972	-$0.30	549	-$0.30	233	$0.10

Key Observations: Day-Ahead Load Scheduling and Virtual Trading

- In aggregate, virtual traders netted approximately $7.5 million of gross profits in 2018 and $6 million in 2017.
  - Profitable virtual transactions over the period indicate that they have generally improved convergence between day-ahead and real-time prices.
  - However, profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices.
- The quantities of virtual transactions that generated substantial profits or losses were generally small in 2018, consistent with prior periods.

These trades were primarily associated with high real-time price volatility that resulted from unexpected events (for example, outages in New England on Labor Day and real-time price spikes during the cold spell in January) and did not raise significant manipulation concerns.

265 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 does not have sufficient capacity to dispatch the least expensive generators to satisfy the demands of the system. 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 the lowest-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 bids to purchase and offers to sell are not scheduled in order to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales 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 TCCs, which entitle the holder to payments corresponding to the congestion charges between two locations. A TCC consists of a source location, a sink location, and a quantity (MW). For example, if a participant holds 150 MW of TCC rights 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 bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract. 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 and B evaluate the congestion revenues collected by the NYISO from the day-ahead market as well as the patterns of congestion on major transmission paths in the day-ahead and real-time markets.

- *Constraints Requiring Frequent Out-of-Market Actions* – Subsection C evaluates the management of transmission constraints that are frequently resolved using out-of-market actions, including the management of the 115 kV and lower voltage network in New York.

- *Congestion Revenue Shortfalls* – Subsections D and E analyze shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- *TCC Prices and Day-Ahead Market Congestion* – Subsection F reviews the consistency of TCC prices and day-ahead congestion, which determine payments to TCC holders.

- *Transitioning Physical Contracts to Financial Rights* – Subsection G 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 in 2018

In this subsection, we summarize the congestion revenues and shortfalls that are collected and settled through the NYISO markets. The vast majority of 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.[266]

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:

- *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.[267] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues. These shortfalls are partly offset by the revenues from selling excess TCCs.

- *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.[268] To reduce flows in real time below the day-ahead schedule, the ISO must increase generation on the import-constrained side of the constraint and reduce generation on the export-constrained side 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) is the balancing congestion shortfall that is recovered through uplift.

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266 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).

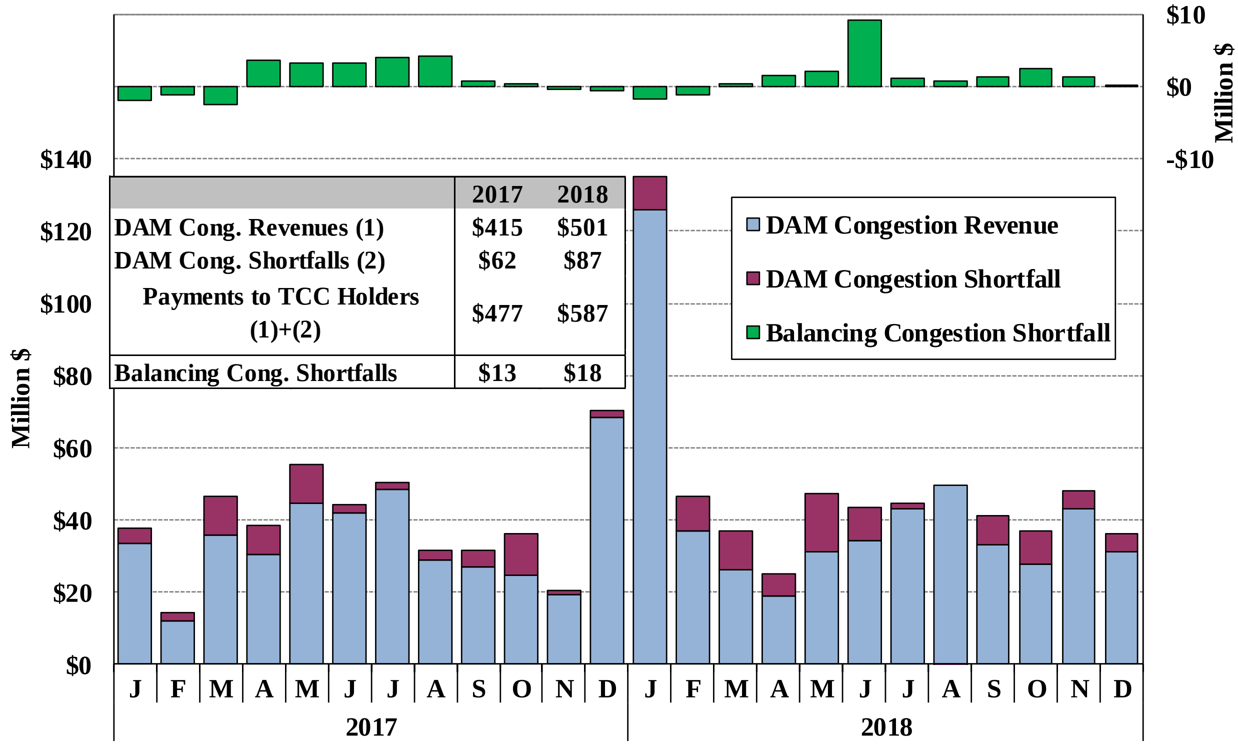
267 For example, suppose 120 MW of TCCs are sold across a particular line. If 100 MW is scheduled to flow when the constraint has a shadow price of $50/MWh in an hour in the day-ahead market, the NYISO will have a day-ahead congestion shortfall of $1,000 in that hour ((120 MW – 100 MW) * $50/MWh).

268 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).

Figure A-48: Congestion Revenue Collections and Shortfalls

Figure A-48 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2017 and 2018. The upper portion of the figure shows balancing congestion revenue shortfalls, and the lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month. The tables in the figure report these categories on an annual basis.

Figure A-48: Congestion Revenue Collections and Shortfalls
2017 - 2018



B. Congestion on Major Transmission Paths

Supply resources in Eastern New York are generally more expensive than those in Western New York, while the majority of the load is located in Eastern New York. Hence, the transmission lines that move power from the low-cost to high-cost parts of the state provide considerable value. 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 needs of the system in real-time. Therefore, it is useful to evaluate the consistency of congestion patterns in the day-ahead and real-time markets.

Figure A-49 to Figure A-51: Day-Ahead and Real-Time Congestion by Path

Figure A-49 to Figure A-51 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-49 compares these quantities in 2017 and 2018 on an annual basis, while Figure A-50 and Figure A-51 show the quantities separately for each quarter of 2018.

The figures measure congestion in two ways:

- 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.[269]

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: Primarily the Central-to-East interface.
- Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the New Scotland-to-Leeds Line, the Leeds-to-Pleasant Valley Line).
- NYC Lines in 345 kV system: Lines leading into and within the New York City 345 kV system.

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

- 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.

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

- All Other: All of other line constraints and interfaces.

Figure A-49: Day-Ahead and Real-Time Congestion by Transmission Path
2017 – 2018

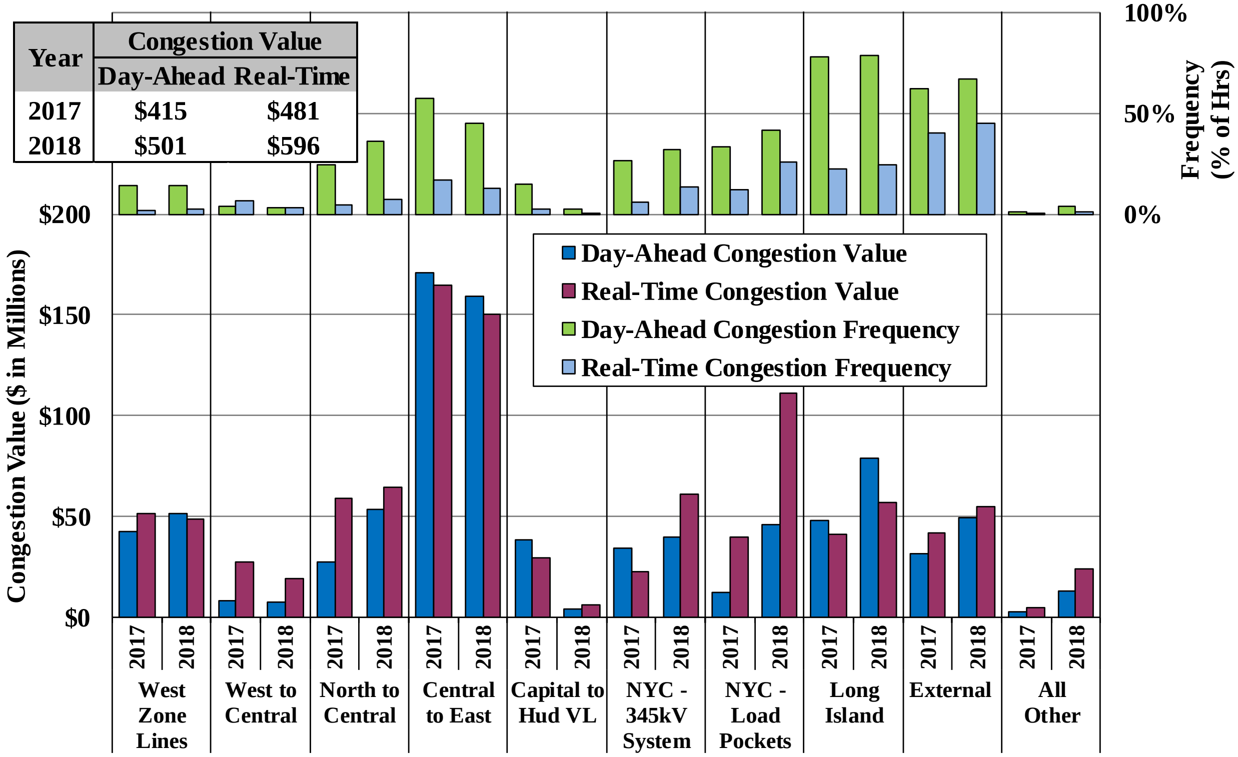
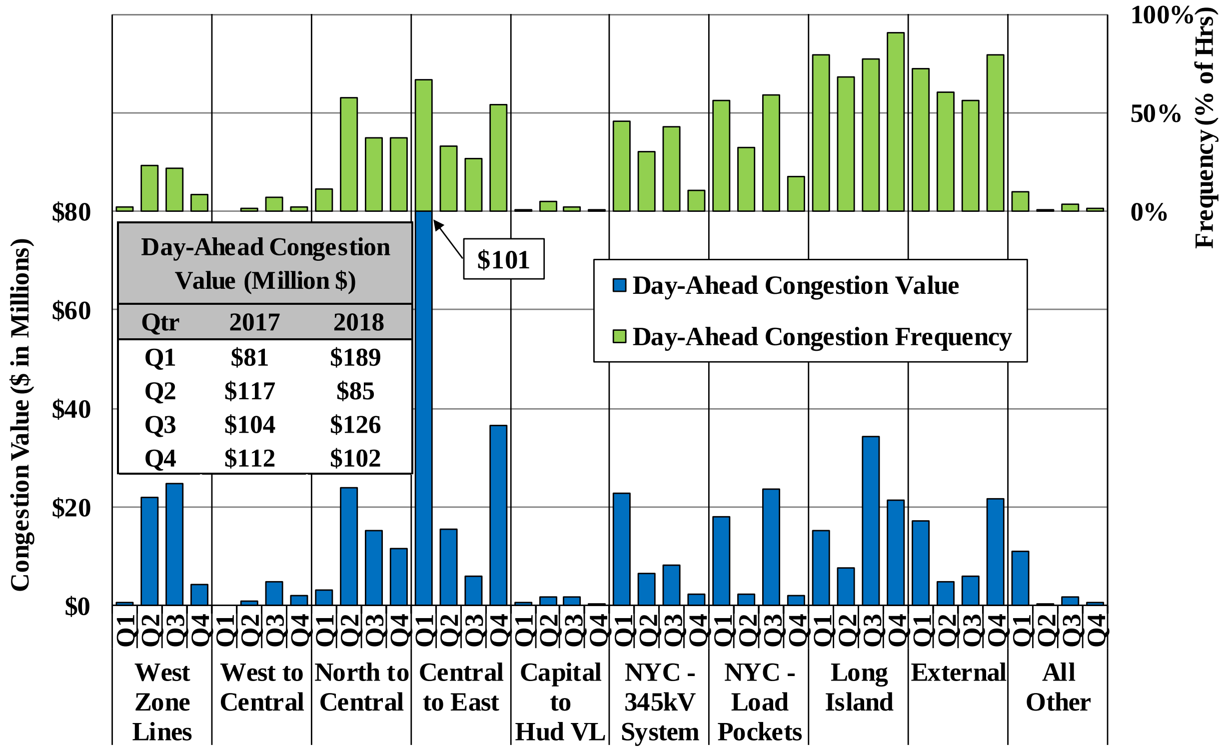
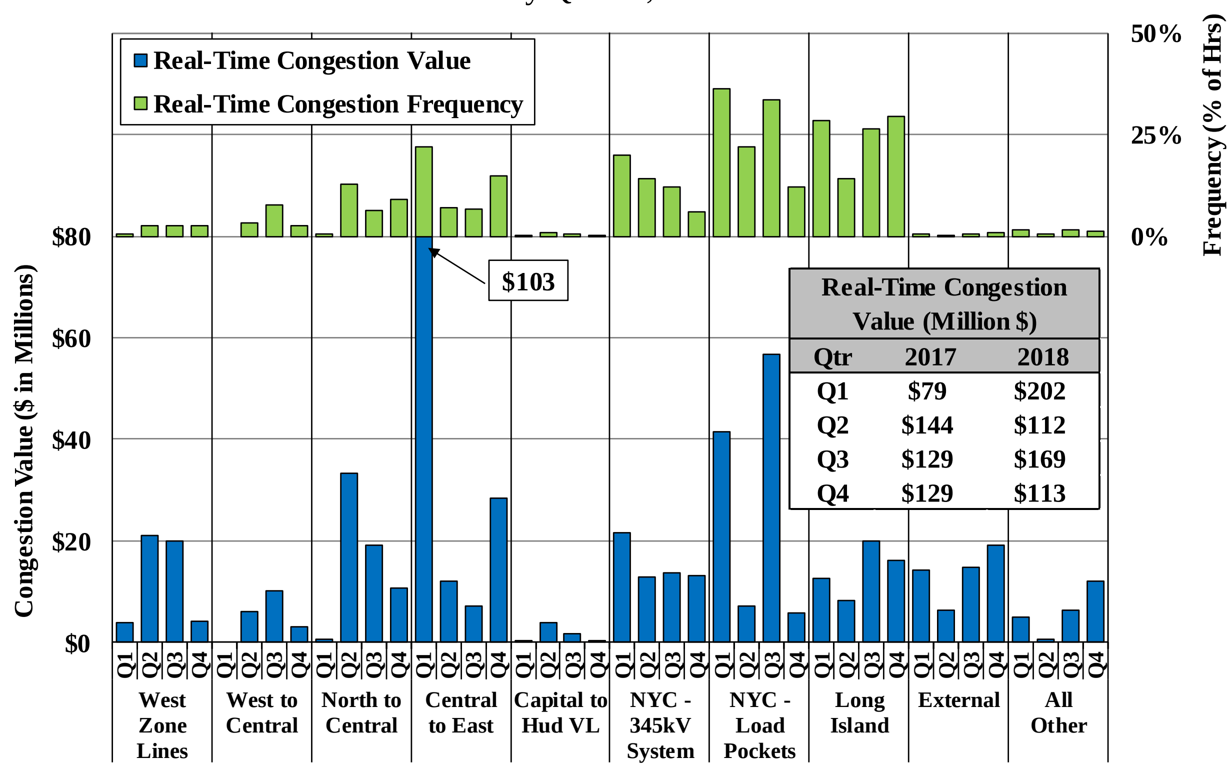


Figure A-50: Day-Ahead Congestion by Transmission Path
By Quarter, 2018



Day-Ahead Congestion Value (Million $)		
Qtr	2017	2018
Q1	$81	$189
Q2	$117	$85
Q3	$104	$126
Q4	$112	$102

Figure A-51: Real-Time Congestion by Transmission Path
By Quarter, 2018



Real-Time Congestion Value (Million $)		
Qtr	2017	2018
Q1	$79	$202
Q2	$144	$112
Q3	$129	$169
Q4	$129	$113

Key Observations: Congestion Revenues and Patterns

- Day-ahead congestion revenues totaled roughly $501 million, up 21 percent from 2017.
  - The increase occurred primarily in the first quarter of 2018, during which day-ahead congestion revenues rose $108 million (or 133 percent) from last year.
    - $56 million (or 29 percent) of day-ahead congestion revenues in the first quarter of 2018 accrued in the first 8 days of the year (during a cold spell, the "Bomb Cyclone") with particularly high natural gas prices.

- Similar to prior years, the largest share of congestion values accrued on the Central-East interface, which accounted for 32 percent of congestion value in the day-ahead market and 25 percent in the real-time market in 2018.
  - The majority of this congestion occurred in the first quarter and in December as a result of higher natural gas prices and larger gas price spreads between regions (which typically increase in the winter season).
  - Nonetheless, this congestion fell modestly from 2017 in spite of higher load levels and increased natural gas prices in 2018 because there were fewer costly transmission outages (see subsection E).

- Congestion rose notably from 2017 to 2018 in New York City.
  - This congestion increased following the expiration of the ConEd/PSEG Wheeling Agreement in May 2017, which resulted in lower imports (by several hundreds of MW) from PJM to New York City across the A, B, and C lines.
  - More costly transmission outages (see subsection E) were another key driver alongside with higher load levels and increased natural gas prices.

- Congestion from North Zone to Central New York increased as well in 2018.
  - Higher congestion was largely driven by more costly transmission outages. (see subsection E)
  - In addition, the NYISO began modeling the Brownfalls-Taylorville 115 kV transmission constraints in May 2018, which contributed to an increase in congestion being reflected in the day-ahead and real-time markets. Furthermore, the CRM values for 115 kV facilities were unnecessarily high when the constraints were first modeled. The NYISO subsequently filed to allow the use of lower CRM values for smaller transmission facilities (see Appendix Section V.G)
  - Frequent congestion on these facilities often led to negative price spikes in the North Zone.

- Congestion on Long Island rose because of higher load, higher gas prices, and more transmission outages.

  - The increase was also attributable to increased congestion on the 138 kV facilities in the summer months, particularly on the East End of Long Island.

- Congestion from Capital to Hudson Valley fell substantially because of fewer transmission outages, while congestion across the external interfaces increased, primarily on the NY/NE interface because of transmission outages.

- Congestion in the West Zone did not change significantly from 2017.

  - Although average clockwise loop flows around Lake Erie, which tend to cause more congestion in the West Zone (see subsection D) increased in 2018, the impact was partially offset by lower imports from Ontario.

  - Unpriced congestion on the 115 kV network in the West Zone (typically managed via OOM actions) was still significant until December 2018. (see subsection C)

C. Transmission Constraints on the Low Voltage Network in New York

In this subsection, we evaluate the actions that are used to manage transmission constraints on the low voltage network in New York, including 115 kV and 69 kV facilities. While such constraints are sometimes managed with the use of line switching on the distribution system, this evaluation focuses on actions that involve wholesale market generators, adjustments to phase-angle regulators on the high-voltage network (including 230+ kV facilities), curtailment or limitation of external transactions, and/or line switching of facilities along the external interfaces with adjacent control areas.

In upstate New York, constraints on 230 and 345 kV facilities are generally managed through the day-ahead and real-time market systems.[270] 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 115 kV and lower voltage networks in New York are resolved in other ways, including: (a) out of merit dispatch and supplemental commitment of generation; (b) curtailment of external transactions and limitations on external interface transfer limits; (c) use of an internal interface/constraint transfer limit that functions as a proxy for the limiting transmission facility; and (d) adjusting PAR-controlled lines on the high voltage network.

270 Note, most transmission constraints on the 138 kV system in New York City and Long Island are also managed using the day-ahead and real-time markets. The primary exception is on the 138 kV network on the east end of Long Island where many constraints are managed using out-of-merit dispatch, which is evaluated in Appendix Section V.I.

Figure A-52 & Figure A-53: Transmission Constraints on the Low Voltage Network

Figure A-52 shows the number of days in 2018 when various resources were used to manage constraints in six areas of New York:

- West Zone: Mostly Niagara-to-Gardenville and Gardenville-to-Dunkirk circuits;
- Central Zone: Mostly constraints around the State Street 115kV bus;
- Capital Zone: Mostly Albany-to-Greenbush 115kV constraints;
- North & Mohawk Valley Zones: Mostly 115kV constraints on facilities that flow power south from the North Zone and through the Mohawk Valley Zone between the Colton 115kV and Taylorville 115kV buses;
- Hudson Valley Zone: Mostly constraints on the 69kV system in the Hudson Valley; and
- Long Island: Mostly constraints on the 69 kV system on Long Island

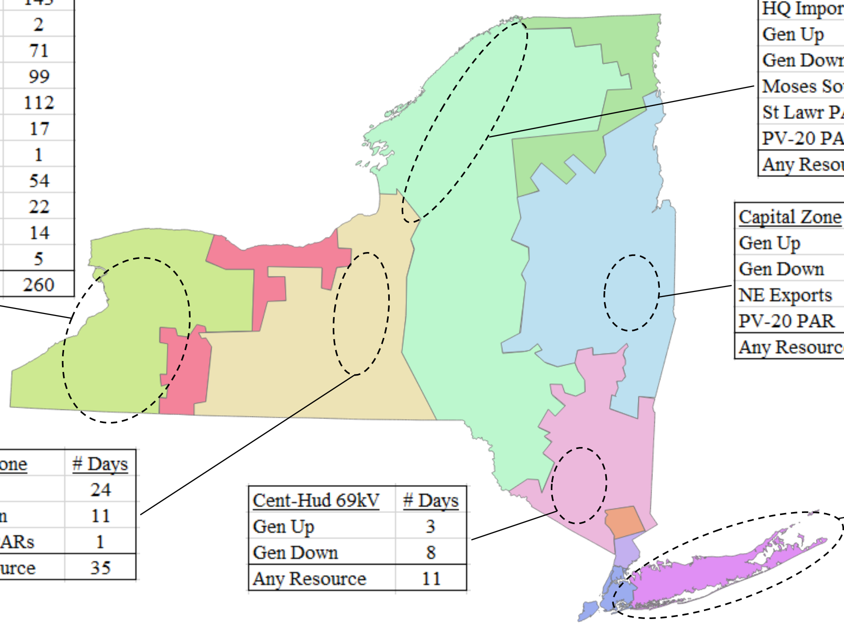
Figure A-52: Constraints on the Low Voltage Network in New York

Summary of Resources Used to Manage Constraint, 2018

West Zone	# Days
Ontario Imports	143
PJM Exports	2
Gen Up	71
Gen Down	99
Proxy 230Kv	112
Dysinger East	17
West Central	1
St Lawr PARs	54
Ramapo PARs	22
ABC PARs	14
Line Reductions	5
Any Resource	260

North Zone	# Days
HQ Imports	17
Gen Up	54
Gen Down	9
Moses South	2
St Lawr PARs	5
PV-20 PAR	1
Any Resource	81

Capital Zone	# Days
Gen Up	12
Gen Down	120
NE Exports	4
PV-20 PAR	1
Any Resource	130



Long Is 69kV	# Days
Gen Up	119
Gen Down	5
Any Resource	121

Central Zone	# Days
Gen Up	24
Gen Down	11
St Lawr PARs	1
Any Resource	35

Cent-Hud 69kV	# Days
Gen Up	3
Gen Down	8
Any Resource	11

Figure A-53 focuses on the area of Long Island, showing the number of hours and days in 2018 when various resources were used to manage 69 kV and TVR (“Transient Voltage Recovery”) constraints in four load pockets of Long Island:

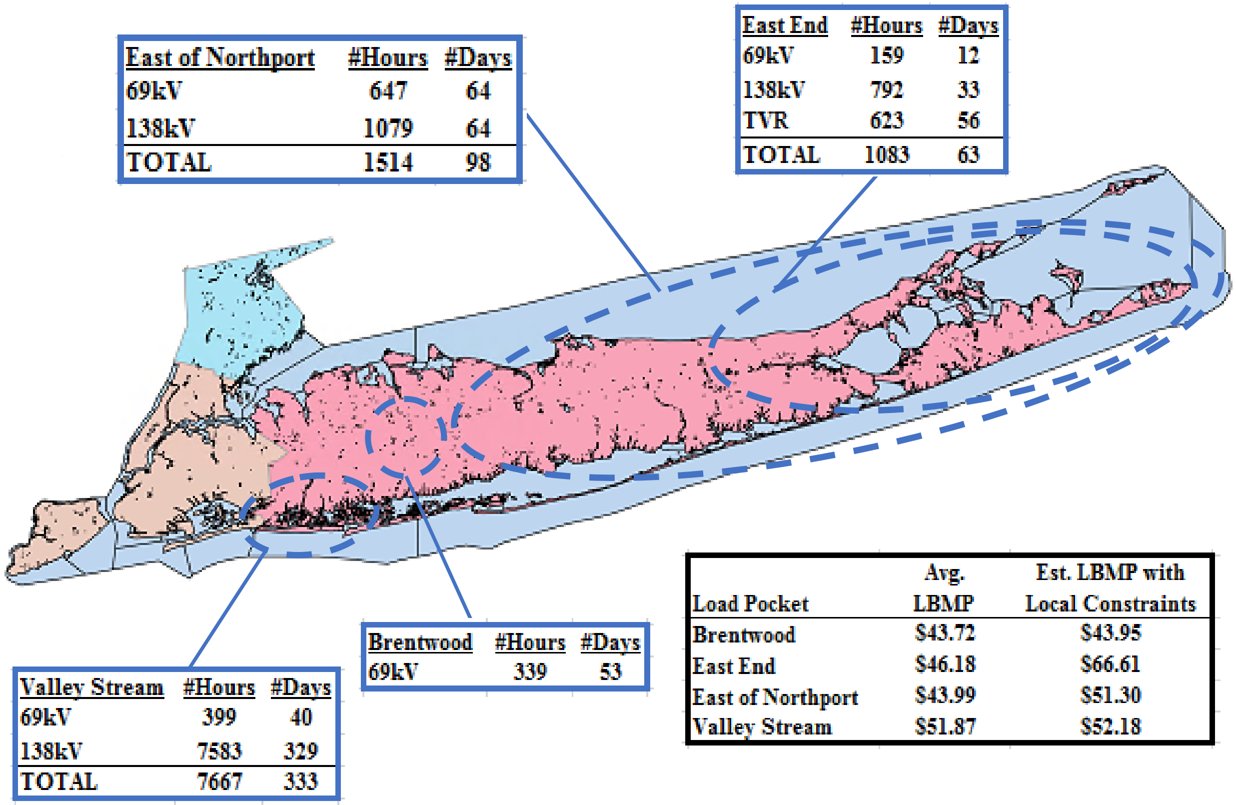
- Valley Stream: Mostly constraints around the Valley Stream bus;
- Brentwood: Mostly constraints around the Brentwood bus;

- East of Northport: Mostly the C._ISLIP-Hauppaug 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 138 kV constraint via the market model. Figure A-53 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. [271]

Figure A-53: Constraints on the Low Voltage Network on Long Island
Frequency of Action Used to Manage Constraint



East of Northport	#Hours	#Days
69kV	647	64
138kV	1079	64
TOTAL	1514	98

East End	#Hours	#Days
69kV	159	12
138kV	792	33
TVR	623	56
TOTAL	1083	63

Brentwood	#Hours	#Days
69kV	339	53

Valley Stream	#Hours	#Days
69kV	399	40
138kV	7583	329
TOTAL	7667	333

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$43.72	$43.95
East End	$46.18	$66.61
East of Northport	$43.99	$51.30
Valley Stream	$51.87	$52.18

<u>Key Observations: Transmission Constraints on the Low Voltage Network in New York</u>

- The West Zone contains the 115 kV facilities most frequently constrained in 2018.
  - Congestion on these constraints has become more prevalent than congestion on the 230 kV network in the West Zone since May 2016.
    - This was partly because transmission upgrades (which were put into service in May 2016 to reduce congestion on 230 kV facilities in the West Zone following

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271 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.

the retirement of the Huntley plant) shifted more west-to-east flows onto the 115 kV network.

- Similar to 2017, resources were utilized to manage 115 kV constraints on 260 days compared to just 167 days with congestion on the 230 kV facilities in the day-ahead and/or real-time markets during 2018.

- Three types of operator actions were most frequent in managing 115 kV constraints (see Figure A-52):
  - Generation and Ontario imports were constrained on most of these days;
  - Surrogate interfaces (i.e., the Dysinger East interface, the West to Central interface, and the Packard-Sawyer 230 kV constraint with an inflated CRM) were used on more than 100 days; and
  - Phase-angle regulators in Northern NY (i.e., the St. Lawr PARs) and Southeast NY (i.e., the Ramapo and ABC PARs) were also used on more than 50 days.
- In addition, (although not shown in the Figure A-52) a 230 kV facility connecting NYISO to PJM, the "Dunkirk-South Ripley" line, was taken out of service to manage 115 kV constraints on almost every day. It was reconnected on just a few days at the request of PJM to facilitate outage work.
- West Zone constraint management not only affected the efficiency of scheduling and pricing in the West Zone but also affected that in other areas of New York because:
  - Reducing low-cost imports from Ontario raised LBMPs in other areas; and
  - Using PARs in the North Zone to relieve West Zone constraints exacerbated constraints going south from the North Zone and across the Central East interface, while using PARs in Southeast New York to relieve West Zone constraints can exacerbate constraints across the Central East interface and into New York City.
- Constraint management should be done in a manner that balances the benefits of relieving constraints in one area against the cost of exacerbating congestion in another. This can be done more effectively if low-voltage constraints were managed using the day-ahead and real-time market systems.
  - The NYISO has recognized this and implemented two market enhancements in December 2018: (a) by modeling 115 kV West Zone constraints in the day-ahead and real-time markets; and (b) by improving modeling of the Niagara plant by better recognizing the different congestion impact from 115 kV and 230 kV units.[272,273]

272 See Section III.C in the Appendix of our 2017 State of the Market report for a detailed illustration of the different congestion impact from 115 kV and 230 kV units.

273 See *Niagara Generation Modeling Update* presented by David Edelson to the Market Issues Working Group on February 21, 2018.

   - Going forward, these two enhancements should greatly improve the efficiency of scheduling and pricing in the West Zone as well as in other areas of New York that were adversely affected by congestion management of West Zone facilities.

- Resources were used to manage 115kV congestion on flows from northern New York towards the central part of the state on only 81 days in 2018 (which was down notably from the 120 days in 2017).
  - The reduction was partly because the NYISO started to model 115 kV constraints in that area in the day-ahead and real-time markets beginning in May 2018. [274]
  - Since the operator actions to manage these 115 kV constraints mostly involved: (a) reducing generation primarily from hydro generating facilities; (b) limiting imports from Quebec across the Cedars-Dennison Scheduled line; and (c) limiting imports from Ontario across the Saint Lawrence PAR-controlled lines, modeling these constraints in the market has helped reduce the overall costs and reliability effects of this congestion.
- Generation OOM dispatch was most frequently used to manage the lower-voltage constraints in other areas of New York. In 2018,
  - OOM down of units occurred on 120 days in the Capital Zone, and
  - OOM up occurred on 119 days on Long Island. OOM actions on Long Island were primarily to manage 69 kV constraints and voltage constraints (TVR requirement on the East End). (see Figure A-53)
- The costs of congestion in the lower-voltage network could be reduced by modeling certain lower-voltage constraints in the day-ahead and real-time markets.
  - The NYISO already started modeling 115 kV constraints in Western New York.
  - We suggest that the NYISO also consider modeling the 69 kV constraints and East End TVR needs (likely via a surrogate thermal constraint) in the market software.
    - This would greatly reduce associated BPCG uplift (roughly $10 million in 2018, see Figure A-91), better compensate resources that satisfy the needs, and provide signals for future investment.
    - Our estimates show that average LBMPs would rise $7.31/MWh East of Northport and $20.43/MWh in the East End load pocket in 2018. (see Figure A-53)

[274] See *Securing 100+kV Transmission Facilities in the Market Model* presented by Ethan Avallone to the Market Issues Working Group on February 21, 2018.

D. Lake Erie Circulation and West Zone Congestion

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York.

Phase angle regulators ("PARs") were installed at the interface between the MISO and IESO in April 2012 partly to control loop flows around Lake Erie. In general, these PARs are used to maintain loop flows at the MISO-IESO interface to less than 200 MW in either direction. Because of the configuration of surrounding systems, the volume and direction of loop flows at the MISO-IESO interface is comparable to the loop flows at the IESO-NYISO interface. The volume of loop flows has been reduced since the PARs were installed in 2012, but excursions outside the 200 MW band still occur on a daily basis, so loop flows continue to have significant effects on congestion patterns in the NYISO.

Figure A-54: Clockwise Loop Flows and West Zone Congestion

Unscheduled clockwise loop flows are primarily of concern in the congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths in Western New York, particularly in the West Zone.

Figure A-54 illustrates how and to what extent unscheduled loop flows affected congestion on market-modeled West Zone constraints in 2017 and 2018. The bottom portion of the chart shows the average amount of: (a) unscheduled loop flows (the blue bar); and (b) changes in unscheduled loop flows from the prior 5-minute interval (the red line) during the intervals when real-time congestion occurred on the West Zone constraints. The congested intervals are grouped based on the following ranges of congestion values: (a) less than \$10,000; (b) between \$10,000 and \$20,000; (c) between \$20,000 and \$50,000; (d) between \$50,000 and \$100,000; (e) between \$100,000 and \$200,000; and (f) more than \$200,000.[275] For a comparison, these numbers are also shown for the intervals with no congestion.

In the top portion of the chart, the bar shows the percent of total congestion values that each congestion value group accounted for in each year of 2017 and 2018, and the number on top of each bar indicates how frequently each congestion value group occurred. For example, the chart shows that the congestion value was more than \$200,000 during 0.04 percent of all intervals in 2018, which however accounted for nearly 20 percent of total modeled congestion value in the West Zone.

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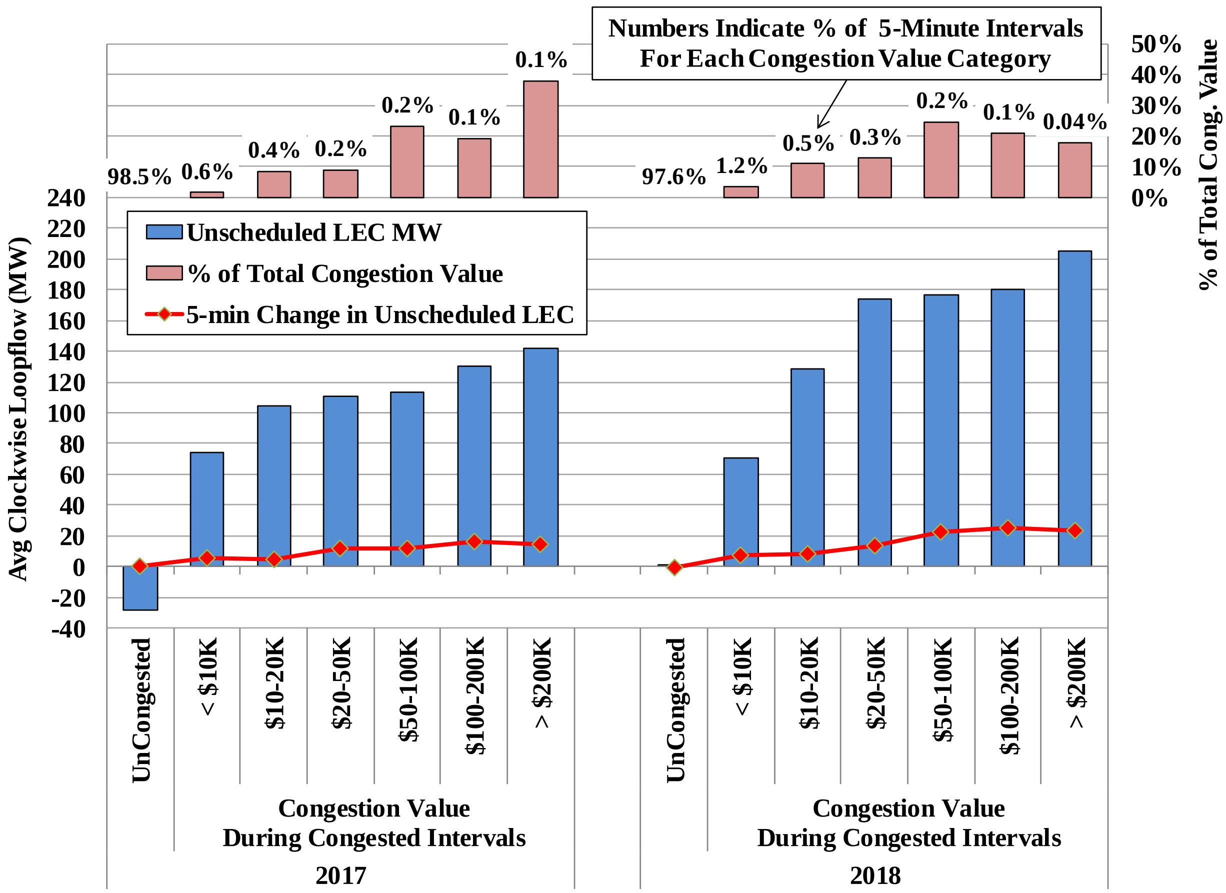
275 The congestion value for each constraint is calculated as (constraint flow × constraint shadow cost × interval duration). Then this is summed up for all binding constraints for the same interval. For example, if a 900 MW line binds with a \$300 shadow price and a 700 MW line binds with a \$100 shadow price in a single 5-minute interval, the resulting congestion value is \$28,333 = (900MW × \$300/MWh + 700MW × \$100/MWh) * 0.083 hours.

Figure A-54: Clockwise Lake Erie Circulation and West Zone Congestion
2017 - 2018



Key Observations: Lake Erie Circulation and West Zone Congestion

- The pattern of loop flows around Lake Erie has shifted in 2018.
  - In uncongested periods (which includes the vast majority of intervals), loop flows have shifted from an average of nearly 30 MW in the counter-clockwise direction in 2017 to a very small amount in the clockwise direction in 2018.
- West Zone congestion was much more prevalent when loop flows were clockwise or happened to swing rapidly in the clockwise direction.
  - A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of unscheduled loop flows and the occurrence of sudden changes from the prior interval.[276]

276 The NYISO implemented two modifications at the end of June 2016 to better manage loop flows: a) a cap of 0 MW on the counter-clockwise loop flows in the RTC initialization; and b) a limit of 75 MW on the maximum change of loop flows between successive RTD initializations. These modifications have helped reduce the severity of real-time congestion during periods with highly volatile loop flows.

- A small number of intervals typically accounted for a relatively large share of the total priced congestion in the West Zone.
  - In 2018, less than 0.05 percent of intervals accounted for nearly 20 percent of the total priced congestion value in the West Zone. Similarly, 0.1 percent of intervals in 2017 accounted for 40 percent of congestion value.
  - This reinforces the importance of efforts to improve congestion management during periods of extreme congestion.
  - The NYISO implemented two market enhancements for West Zone congestion management in December 2018: (a) model 115 kV West Zone constraints; and (b) improve modeling of the Niagara plant. These should help greatly improve the efficiency of congestion management in the West Zone.

E. Day-Ahead and Balancing Congestion Shortfalls by Path or Constraint

Congestion shortfalls generally occur as a result 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-55: 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 should 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 otherwise not consistent with the assumptions used in the day-ahead market, the congestion revenues collected may be insufficient to meet TCC obligations.

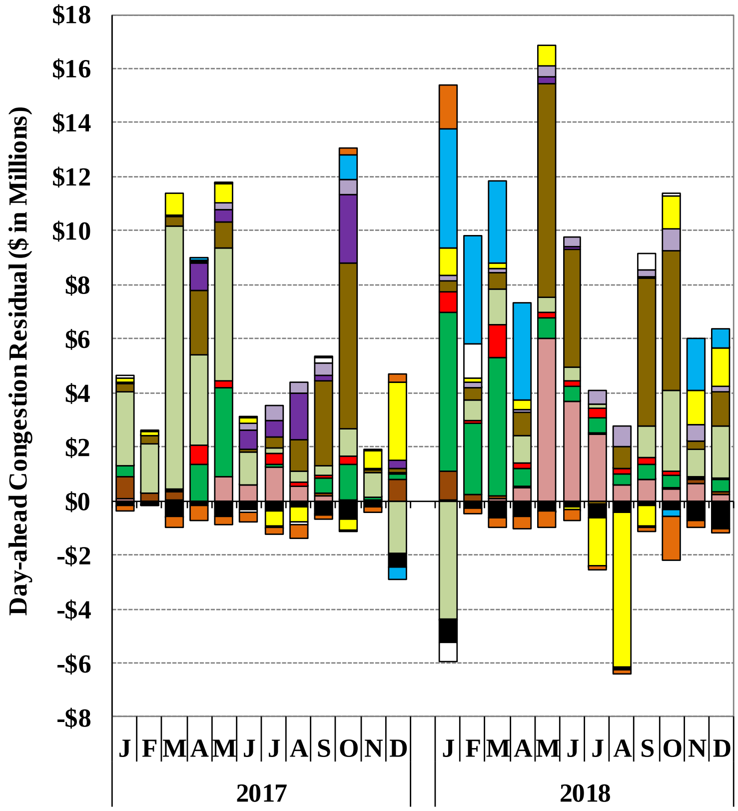
Figure A-55 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2017 and 2018. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- 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.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Transmission lines into Hudson Valley, primarily lines connecting Leeds, Pleasant Valley, and New Scotland stations.
- New York City Lines: Lines leading into and within New York City.
- Long Island Lines: Lines leading into and within Long Island.
- External: Congestion 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 the Central-East interface, the figure shows separately the shortfalls resulted from differences in assumed flows on the PAR controlled lines between New York and New Jersey (including Ramapo, ABC, and JK PARs) between the TCC auction and the day-ahead market.
- For Long Island lines, the figure shows separately the shortfalls resulted from:
    - Grandfathered TCCs ("GFTCC") that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K); and
    - 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.

Figure A-55: Day-Ahead Congestion Shortfalls
2017 – 2018



	Category	Annual Shortfall ($M) 2017	Annual Shortfall ($M) 2018
	West Zone Lines	$3.5	$15.5
	Central to East		
	Ramapo, ABC & JK PARs	$2.2	$1.9
	Other Factors	$24.7	$7.2
	North to Central	$15.5	$27.4
	Capital to Hud VL	$7.6	$0.3
	New York City		
	ABC PARs	$2.0	$3.6
	Other Factors	$7.4	$18.1
	Long Island Lines		
	901/903 PARs	-$4.2	-$6.0
	Excess GFTCC Allocations	$2.7	$4.5
	Other Factors	$4.0	-$2.0
	External		
	Primary NY/NE	$0.6	$17.3
	Other	-$2.4	-$2.8
	All Other Facilities	$0.1	$1.3

Figure A-56: Balancing Congestion Revenue Shortfalls

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.

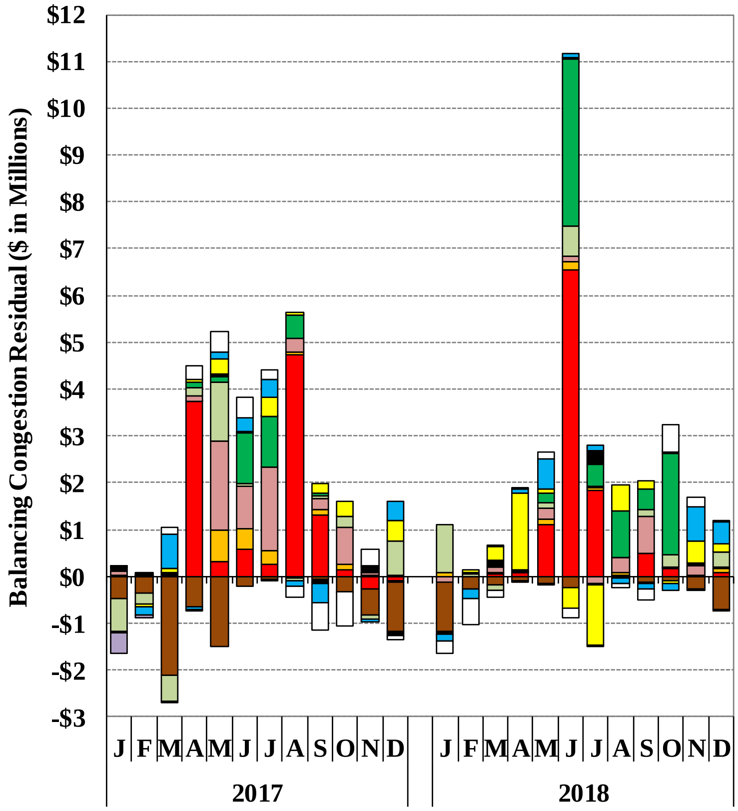
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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.

The net cost of the redispatch in real-time due to changes from day-ahead (i.e., balancing congestion shortfalls) is collected from loads through uplift charges, most of which is allocated to load throughout the state. However, a portion associated with facilities that require special operation during TSA events is charged to Consolidated Edison whose customers benefit most directly from the additional reliability.

Similar to Figure A-55, Figure A-56 shows balancing congestion shortfalls by transmission path or facility in each month of 2017 and 2018. For select transmission paths, the figure also shows the shortfalls resulted from some unique factors separately from other reasons. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-56: Balancing Congestion Shortfalls[277]
2017 – 2018



	Category	Annual Shortfall ($M) 2017	2018
	West Zone Lines		
	Ramapo, ABC & JK PARs	**$1.8**	**$0.6**
	Other Factors	**$6.2**	**$1.6**
	North to Central	**$10.7**	**$10.3**
	Central to East		
	Ramapo, ABC & JK PARs	**-$7.4**	**-$3.2**
	Other Factors	**$0.8**	**$2.5**
	TSA Constraints	**$3.0**	**$7.9**
	Long Island Lines		
	901/903 PARs	**$0.1**	**$0.4**
	Other Factors	**$1.8**	**$1.6**
	External	**$1.1**	**$1.5**
	PJM M2M Payment	**-$0.5**	**$0.0**
	All Other Facilities	**$0.3**	**-$0.6**

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled $87 million in 2018, up 40 percent from 2017, driven primarily by more costly transmission outages in 2018.
  - In 2018, roughly $71 million (or 82 percent) were allocated to responsible Transmission Owners for transmission outages.
- Transmission constraints categorized as "North to Central" accounted for more than $27 million of shortfalls in 2018, up 77 percent from 2017.
  - Nearly 75 percent of shortfalls accrued on one of the Marcy 345 kV lines or the Moses-Adirondack 230 kV lines when their parallel paths was out-of-service on many days in May, September, October, and December.

277 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.

  - Most of the remaining shortfalls accrued on the Brownfalls-Taylorville 115 kV lines in June when one of the these facilities was out-of-service.

- Nearly $22 million of shortfalls accrued on New York City lines in 2018, up 133 percent from 2017.

  - Nearly 60 percent of these shortfalls accrued on the 345 kV transmission facilities into New York City (from upstate) when:

    - One of the Dunwoodie-Motthaven 345 kV lines was out-of-service from the beginning of March to early April, and from the beginning of July to early October; and

    - The B and C PAR-controlled lines were out-of-service from mid-January to the end of the year.

  - The majority of the remaining shortfalls accrued on transmission lines into the Greenwood load pocket, primarily in January and February when one of the Gowanus-Greenwood lines was out-of-service.

- The primary NY/NE interface accounted for more than $17 million of shortfalls in 2018, which was unusually high.

  - This was because the interface limit was greatly reduced (from 1,400 MW to around 500 MW) when:

    - The New Scotland-Alps 345 kV line was out-of-service from mid-January to mid-February; and

    - The Long Mountain-Pleasant Valley 345 kV line was out-of-service from late February to early May, and from late November to early December.

- The transmission paths in the West Zone saw an increase in shortfalls from 2017, largely because of more costly transmission outages in 2018.

  - Over 45 percent (or $7 million) of shortfalls occurred during the outage of Niagara-Robinson Rd 230 kV line on several days from late May to early June.

  - In addition, contribution (to West Zone shortfalls) from different loop flow assumption between the TCC auction and the day-ahead market became larger as average clockwise loop flows increased from 2017 to 2018.

- Conversely, the Central-East interface and transmission paths from Capital to Hudson Valley accrued substantially less shortfalls in 2018, mostly attributable to fewer transmission outages.

- The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) consistently caused congestion surpluses because of the differences in the schedule assumptions on these two lines between the TCC auction and the day-ahead market. [278]

- o The TCC auctions typically assumed a total of 300 MW flow from Long Island to New York City across the two lines while the day-ahead market assumed lower values—an average of 197 MW in that direction in 2017 and 205 MW in 2018.
- o Since flows from Long Island to New York City across these lines are generally uneconomic and raise production costs, reducing the assumed flow from the TCC auction to the day-ahead market led to significant surplus congestion revenue, which reinforces the notion that scheduling the 901 and 903 lines in an efficient manner would substantially reduce production costs.

Balancing Congestion Shortfalls

- Balancing congestion shortfalls totaled $18 million in 2018, up 38 percent from 2017.
- Balancing congestion shortfalls were generally small on most days of 2018 but rose notably on several days when unexpected real-time events occurred.
  - o TSA events were a key driver of high balancing shortfalls on these days, during which the transfer capability into SENY was greatly reduced in real time.
    - This led to a total of $8 million of shortfalls.
  - o Unplanned/forced outages were another dominant driver. Notable examples include:
    - Roughly $1.5 million of shortfalls accrued on Long Island when the Y49 line (from Dunwoodie to Long Island) tripped on April 28 and returned the next day.
    - Over $6 million of shortfalls accrued in the North Zone from June 1 to June 5 when the UCC2-41 Line (i.e., the Marcy-Frasannx-Coopers Corners line) was forced out because of relay issues.
    - Another $2 million of shortfalls accrued in the North Zone from July 4 to July 7 when unplanned transmission outages occurred in real time (which were not reflected in the day-ahead market).
- The PAR operations under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flowgates,
  - o Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $3.2 million of surpluses on the Central-East interface in 2018.
  - o However, this was lower than the $7.4 million in 2017, partly because the B and C PAR-controlled lines were out-of-service during almost the entire year (from mid-January to the end of the year).

[278] This is categorized as "901/903 PARs" under "Long Island Lines" in the figure.

- The Ramapo PARs normally accrued the most surpluses, reflecting that the Ramapo PARs are operated more actively than the ABC and JK PARs to reduce congestion. (see Appendix Section V.D)

F. 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* [279] – 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-57: TCC Cost and Profit by Auction Round and Path Type

Figure A-57 summarizes TCC cost and profit for the Winter 2017/18 and Summer 2018 Capability Periods (i.e., the 12-month period from November 2017 through October 2018). 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 2017/18 Capability Period; (c) four rounds of six-month auctions for the Summer 2018 Capability Period; and (d) twelve Balance-

279 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.

of-Period auctions for each month of the 12-month Capability Period. [280] The figure only evaluates the TCCs that were purchased by Market Participants in these auctions.

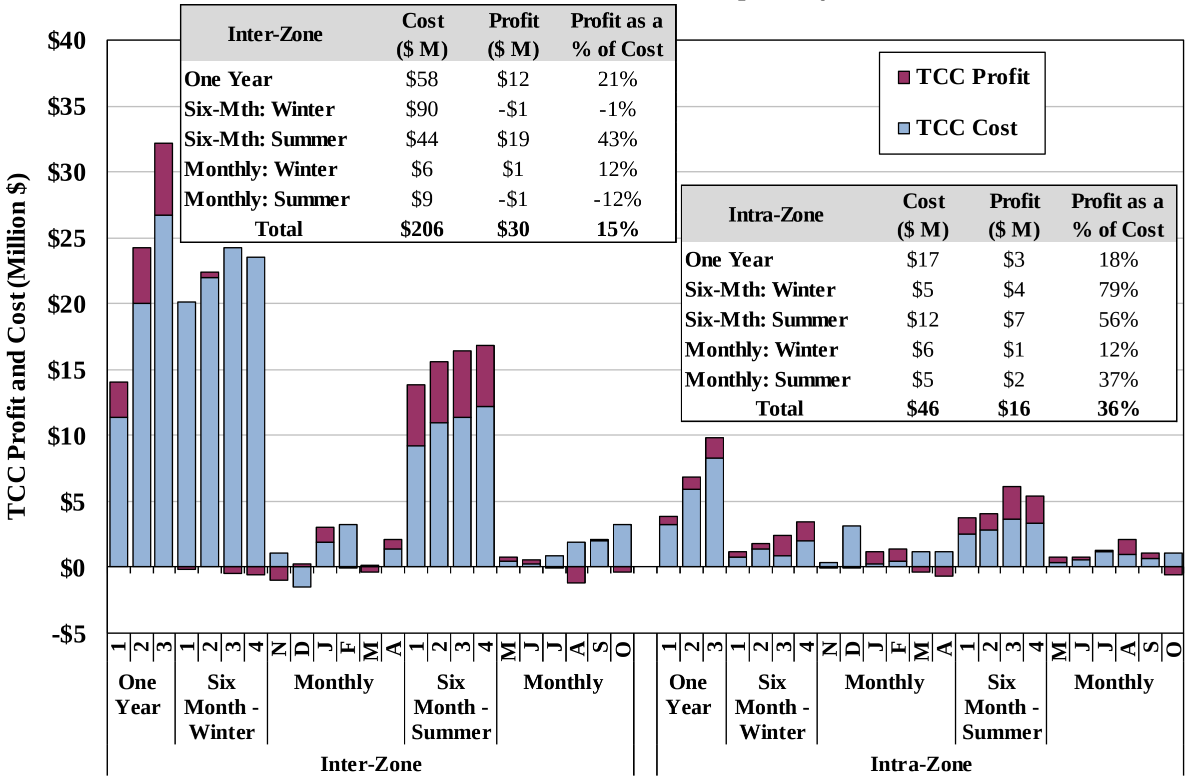
For the purposes of the figure, each TCC is broken into inter-zonal and intra-zonal components, making it possible to identify portions of the transmission system that generate the most revenue in the TCC auction and that are most profitable for the buyers of TCCs. Each TCC has a Point-Of-Injection ("POI") 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.[281]

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.

280 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

281 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.

Figure A-57: TCC Cost and Profit by Auction Round and Path Type
Winter 2017/18 and Summer 2018 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$58	$12	21%
Six-Mth: Winter	$90	-$1	-1%
Six-Mth: Summer	$44	$19	43%
Monthly: Winter	$6	$1	12%
Monthly: Summer	$9	-$1	-12%
Total	**$206**	**$30**	**15%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$17	$3	18%
Six-Mth: Winter	$5	$4	79%
Six-Mth: Summer	$12	$7	56%
Monthly: Winter	$6	$1	12%
Monthly: Summer	$5	$2	37%
Total	**$46**	**$16**	**36%**

Table A-2 & Table A-3: 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 2017/18 and Summer 2018 Capability Periods (i.e., the 12-month period from November 2017 through October 2018). 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-2: TCC Cost by Path
Winter 2017/18 and Summer 2018 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	$13	-$2	-$5	-$1	$0	$0	$40	$0	$0	$0	$0	-$6	$0	$0	$0	$39
GENESE	$3	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$3
CENTRL	$16	-$2	$8	$0	-$4	$0	$31	$0	$0	$0	$0	$0	$0	$0	$1	$50
MHK VL	$7	$0	$1	-$7	-$1	$1	$0	$0	$0	$0	$0	$0	$0	$10	$0	$11
NORTH	$3	$2	$9	$20	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$36
CAPITL	$0	$0	-$1	-$2	$0	$9	-$8	$0	$0	$0	$0	$0	$0	$0	$0	-$3
HUD VL	$0	$0	-$2	$0	$0	$9	$2	$1	$2	$34	$0	$0	$0	$15	-$3	$57
MILLWD	$0	$0	$0	$0	$0	$0	-$1	$1	$1	$0	$0	$0	$0	$0	$0	$1
DUNWOD	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$4	$1	$0	$0	$0	$0	$4
N.Y.C.	$0	$0	$0	$0	$0	$0	-$8	-$1	-$1	$12	$0	$0	$0	$0	$0	$2
LONGIL	$0	$0	-$1	$0	$0	$0	$0	$0	-$1	-$1	$8	$0	$0	$0	$0	$5
O H	$5	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$7
H Q	$1	$0	$3	$25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29
NPX	$0	$0	$0	$0	$0	$0	-$2	$0	$0	$0	$0	$0	$0	$0	$0	-$2
PJM	-$2	-$1	-$6	$0	$0	$0	$23	$0	$0	$1	$0	$0	$0	$0	$0	$15
Total	**$46**	**-$2**	**$7**	**$35**	**-$5**	**$19**	**$78**	**$0**	**$0**	**$50**	**$9**	**-$7**	**$0**	**$25**	**-$2**	**$252**

Table A-3: TCC Profit by Path
Winter 2017/18 and Summer 2018 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$0	$1	$2	$0	$0	$0	-$15	$0	$0	$0	$0	$1	$0	$0	$0	-$12
GENESE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CENTRL	-$2	$0	$3	-$1	$0	$0	-$13	$0	$0	$0	$0	$0	$0	$0	-$1	-$14
MHK VL	$1	$0	$2	-$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NORTH	$1	$0	$1	$12	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14
CAPITL	$0	$0	$0	$1	$0	-$2	$0	$0	$0	$0	$0	$0	$0	$8	$0	$7
HUD VL	$1	$0	$0	$0	$0	-$2	-$1	$0	$0	$4	$0	$0	$0	$16	$1	$19
MILLWD	$0	$0	$0	$0	$0	$0	$0	$1	$2	$0	$0	$0	$0	$0	$0	$3
DUNWOD	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$1	$0	$0	$0	$0	$0	$0
N.Y.C.	$0	$0	$0	$0	$0	$0	-$2	-$1	$0	$12	$0	$0	$0	$0	$0	$9
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7	$0	$0	$0	$0	$8
O H	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$2
H Q	$0	$0	$1	$10	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$12
NPX	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	-$1
PJM	$3	$0	$3	$0	$0	$0	-$3	$0	$0	$0	$0	$0	$0	$0	$0	$3
Total	**$3**	**$1**	**$12**	**$19**	**-$1**	**-$4**	**-$36**	**$0**	**$1**	**$17**	**$7**	**$2**	**$0**	**$24**	**$0**	**$47**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a total profit of $47 million in the TCC auctions during the reporting 12-month period (November 2017 to October 2018), resulting in an average profitability (profit as a percent of TCC cost) of 19 percent. [282]

- TCC profitability coincided with changes in the congestion pattern from the prior year.

282 The reported profits exclude profits and losses from TCC sellers (i.e., firms that initially purchased TCCs and then sold back a portion in a subsequent auction). In addition, purchases in the TCC auctions that include months outside the evaluated 12-month period are not included as well. Therefore, this evaluation does not include any two-year TCC auctions nor the two one-year TCC auctions that were conducted in the Spring of 2017 and 2018. This is because it is not possible to identify the portion of the purchase cost for such a TCC that was based on its expected value during the period from November 2017 to October 2018.

- For example, TCC buyers netted a $16 million profit off a $15 million purchase cost on transmission paths from the Hudson Valley Zone to New England.
  - This coincided with unusually higher congestion across the primary NY/NE interface and substantially lower congestion from Capital to Hudson Valley (for the reasons discussed in subsection B).
- A total of $22 million profit (off a $45 million purchase cost) accrued on transmission paths from HQ and the North Zone to the Mohawk Valley Zone.
  - This coincided with a 95 percent increase in day-ahead congestion on “North to Central” transmission facilities (see Figure A-49).
- Consistent with these changes in the congestion pattern, TCC buyers netted the most loss on transmission paths sourcing from the West Zone and the Central Zone to the Hudson Valley Zone.
- These results indicate that market participants’ anticipated congestion levels were generally in line with the levels observed in the prior year.

G. 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:

- <u>Basecase Scenario</u> – 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.
- <u>PAR Relief Scenario</u> – 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.
- <u>PAR Loading Scenario</u> – 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.[283,284] 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 lowers the cost of serving load in New York to the extent that 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 costs 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 three aspects of transaction scheduling between New York and adjacent control areas:

- Scheduling patterns between New York and adjacent control areas;
- Convergence of prices between New York and neighboring control areas; and
- The efficiency of Coordinated Transaction Scheduling ("CTS"), including an 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.

283 The Cross Sound Cable ("CSC"), which connects Long Island to Connecticut, is frequently used to import up to 330 MW to New York. Likewise, the Neptune Cable, which connects Long Island to New Jersey, is frequently used to import up to 660 MW to New York. The Northport-to-Norwalk line ("1385 Line"), which connects Long Island to Connecticut, is frequently used to import up to 200 MW. The Linden VFT Line, which 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.

284 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 which is scheduled separately from the primary interface between New York and Quebec.

A. Summary of Scheduled Imports and Exports

Figure A-58 to Figure A-61 : Average Net Imports from Ontario, PJM, Quebec, and New England

The following four figures summarize the net scheduled interchanges between New York and neighboring control areas in 2017 and 2018. 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-58, the primary interfaces with Quebec and New England in Figure A-59, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-60 and Figure A-61.

Figure A-58: Monthly Average Net Imports from Ontario and PJM
2017 – 2018

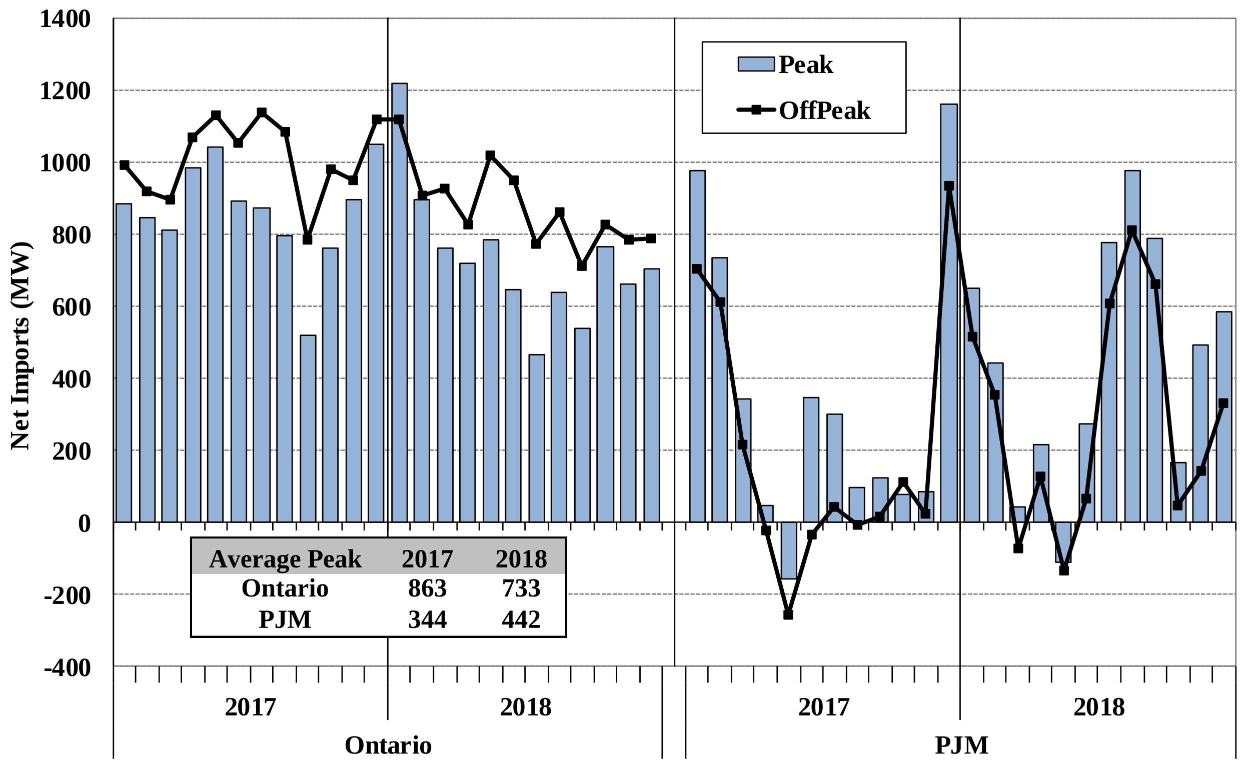


Figure A-59: Monthly Average Net Imports from Quebec and New England
2017 – 2018

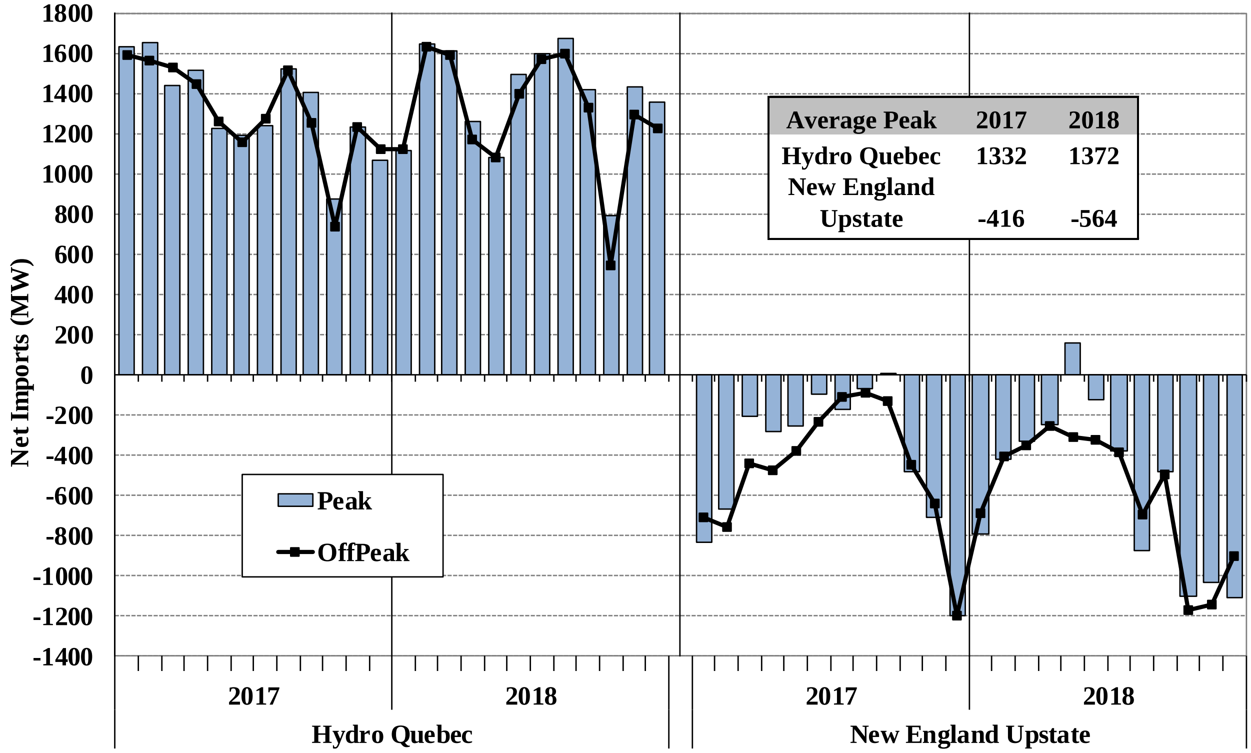


Figure A-60: Monthly Average Net Imports into New York City
2017 – 2018

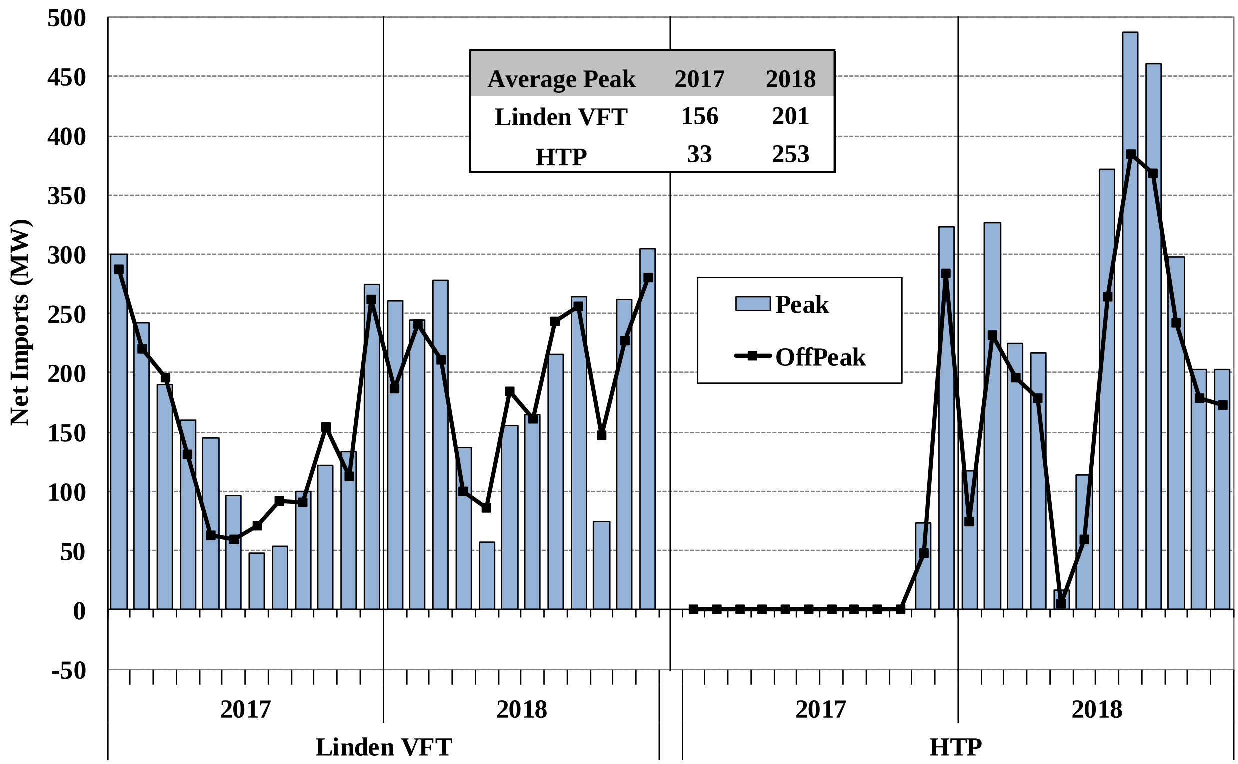
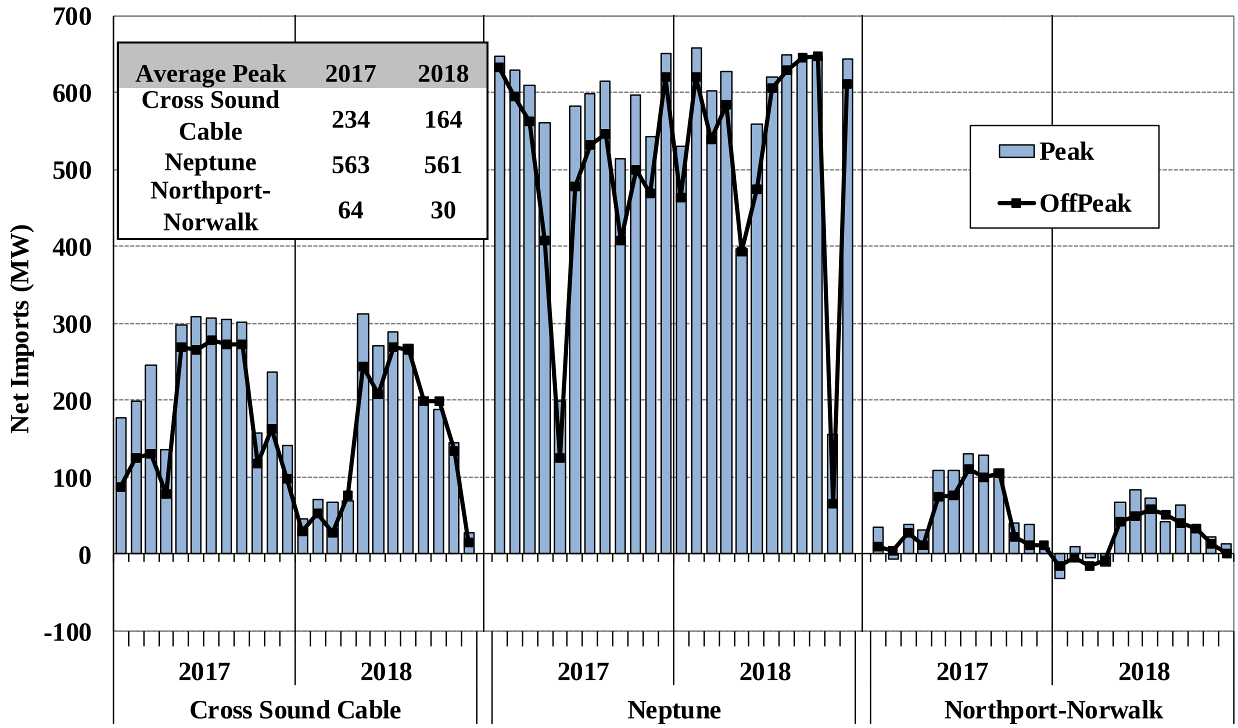


Figure A-61: Monthly Average Net Imports into Long Island
2017 – 2018



Key Observations: Average Net Imports

- Total net imports averaged roughly 3,190 MW during peak hours in 2018, which rose slightly from 2017 and served approximately 17 percent of all load.
- Average net imports from neighboring areas across the primary interfaces fell 7 percent from about 2,125 MW in 2017 to 1,985 MW in 2018 during the peak hours.
  - Net imports from HQ averaged roughly 1,370 MW, accounting for nearly 70 percent of net imports across the primary interfaces in 2018. Imports from HQ were high in most months of 2018 but fell notably in April and October when the interface was OOS for 7 and 15 days, respectively.
  - Average net imports from Ontario fell 130 MW (or 15 percent) from 2017 to 2018. Net imports fell the most in the second quarter of 2018, partly because of higher prices on the Ontario side (the Ontario HOEP averaged $19/MWh in the second quarter of 2018, much higher than $6/MWh in the second quarter of 2017).
  - New York was typically a net importer from PJM and a net exporter to New England across their primary interfaces. Both net imports from PJM and net exports to NE increased from 2017 to 2018, consistent with larger gas price spreads between these

markets in 2018. However, some lengthy key transmission outages on the two interfaces limited the increases.[285]

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged 755 MW during peak hours in 2018, down 12 percent from 2017.
  - The reduction occurred primarily on the two controllable interfaces with NE, consistent with higher gas prices on the NE side.
  - Net imports across the Neptune Cable were normally fully scheduled during peak hours but fell notably in May and November 2018 because of the cable was OOS for one week and three weeks in the two months, respectively.
  - Imports over the three controllable interfaces account for a large share of the supply to Long Island, serving slightly more than 30 percent of the load in Long Island in recent years.
- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged 455 MW during peak hours in 2018, up 141 percent from 2018.
  - The increase reflected higher LBMPs in the 345 kV system of New York City for the reasons discussed in Section III.B of the Appendix and the return of the HTP interface from a lengthy outage.

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.

285 The B and C PAR-controlled lines (part of the NY/PJM interface) were OOS from mid-January to the end of the year, limiting flows from PJM to Eastern New York across its primary interface. The New Scotland-ALPS and the Long Mountain-Pleasant Valley 345 kV lines were OOS in various periods of 2018 for a total of roughly 4 months, during which the NY/NE interface was greatly reduced to around 500 MW.

- 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 cannot be expected 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-62: Price Convergence Between New York and Adjacent Markets

Figure A-62 evaluates scheduling between New York and adjacent RTO markets across interfaces with open scheduling. The Neptune Cable, the Linden VFT Line, the HTP Line, and the Cross Sound Cable are omitted because these are Designated Scheduled Lines and alternate systems are used to allocate transmission reservations for scheduling on them. 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-62 summarizes price differences between New York and neighboring markets during unconstrained hours in 2018. 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.[286] 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.

286 In these hours, prices in ISO-NE and PJM (i.e., prices at the NYISO proxy in each RTO market are used) reflect transmission constraints in those markets, but the price used here for Ontario (i.e., the Ontario HOEP) does not incorporate such constraints.

Figure A-62: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2018

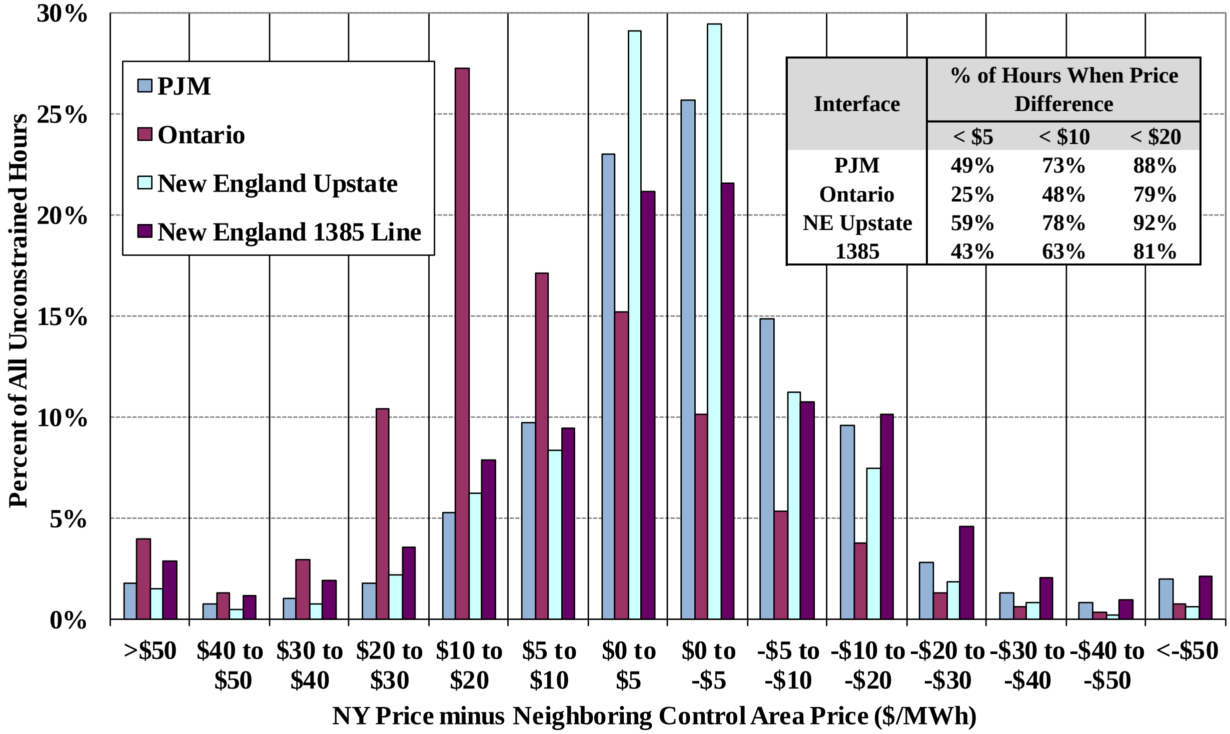


Table A-4: Efficiency of Inter-Market Scheduling

Table A-4 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2018. 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. [287]

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287 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.

- 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 than the other side of the interface.

- 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.[288]

Table A-4 evaluates the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but this will induce other firms to schedule counter-flow transactions, thereby offsetting the effect of 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-4: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2018

	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	-680	$1.42	42%	-$6	101	$1.53	55%	$7
Ontario	762	$10.97	85%	$86	46	$11.31	56%	$2
PJM	336	-$1.04	63%	$1	22	-$1.01	61%	$6
Controllable Ties								
1385 Line	41	-$0.03	70%	$3	-17	-$0.13	52%	$1
Cross Sound Cable	153	$0.15	74%	$5	-0.2	$0.63	55%	-$0.2
Neptune	541	$7.82	88%	$33	0.0	$7.60	55%	$0.4
HTP	177	$1.85	77%	$6	45	$2.74	62%	$2
Linden VFT	151	$4.20	89%	$9	45	$0.41	60%	$2

288 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.

Key Observations: Efficiency of Inter-Market Scheduling

- The distribution of price differences across New York's external interfaces indicates that the current process does not maximize the utilization of the interfaces.
  - While the price differences are relatively evenly distributed around $0 (excluding Ontario),[289] a substantial number of unconstrained hours (8 to 19 percent) had price differences exceeding $20/MWh for every interface in 2018.
  - Price differences at the CTS interfaces (PJM and ISO-NE) were smaller than for the hourly-scheduled Northport-to-Norwalk interface, reflecting that CTS has improved the utilization of the interfaces (see the inset table in Figure A-62).
    - Similarly, the price differences at the CTS interface with ISO-NE were smaller than the price differences at the CTS interface with PJM, which is at least in part due to the better performance of CTS with ISO-NE.
- In the day-ahead market, the share of hours scheduled in the efficient direction was higher over the controllable lines than over the free-flowing ties, reflecting generally less uncertainty in predicting price differences across these controllable lines in 2018.
- Real-time adjustments in flows were generally more frequent across the free-flowing ties, since market participants generally responded to real-time price variations by increasing net flows into the higher-prices region across these ties.
  - A total of $13 million in real-time production cost savings was achieved in 2018 from the real-time adjustments over the PJM and New England free-flowing interfaces.
- Although significant production cost savings have been achieved through transaction scheduling over New York's external interfaces, there was still a large share of hours when power flowed inefficiently from the higher-priced market to the lower-priced market. Even in hours when power is flowing in the efficient direction, the interface is rarely fully utilized.
  - These scheduling results indicate the difficulty of predicting changes in real-time market conditions and the other costs and risks that interfere with efficient interchange scheduling.

C. Evaluation of Coordinated Transaction Scheduling

Coordination Transaction Scheduling ("CTS") is a novel market design concept whereby two wholesale market operators exchange information about their internal prices shortly before real-time and this information is used to assist market participants in scheduling external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the hourly LBMP-based scheduling system:

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289 The distribution at the Ontario-NYISO border is skewed because the HOEP understates the border price when there is congestion to the border on the Ontario side.

- CTS bids are evaluated relative to the adjacent ISO's short-term forecast of prices, while the previous system required bidders to forecast prices in the adjacent market.

- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established up to 105 minutes in advance, while schedules are now 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-63: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

The first analysis examines the trading volumes of CTS transactions in 2018. In particular, Figure A-63 shows the average amount of CTS transactions at the primary PJM and New England interfaces during peak hours (i.e., HB 7 to 22) in each month of 2018. 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 (i.e., bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis) 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.[290] The traditional LBMP-based bids still co-exist with the CTS bids 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 CTS imports and exports (including 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 CTS bids with low offer prices, which are either less than $5/MWh or between $5 and $10/MWh; and b) the average cleared CTS bids in 2018. Both imports and exports are included in these numbers, which also include the equivalent CTS transactions that are converted from LBMP-based transactions.

290 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. 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 less (b) the bid price.

Figure A-63: Price-Sensitive Real-Time Transaction Bids and Offers by Month
PJM and NE Primary Interfaces, 2018

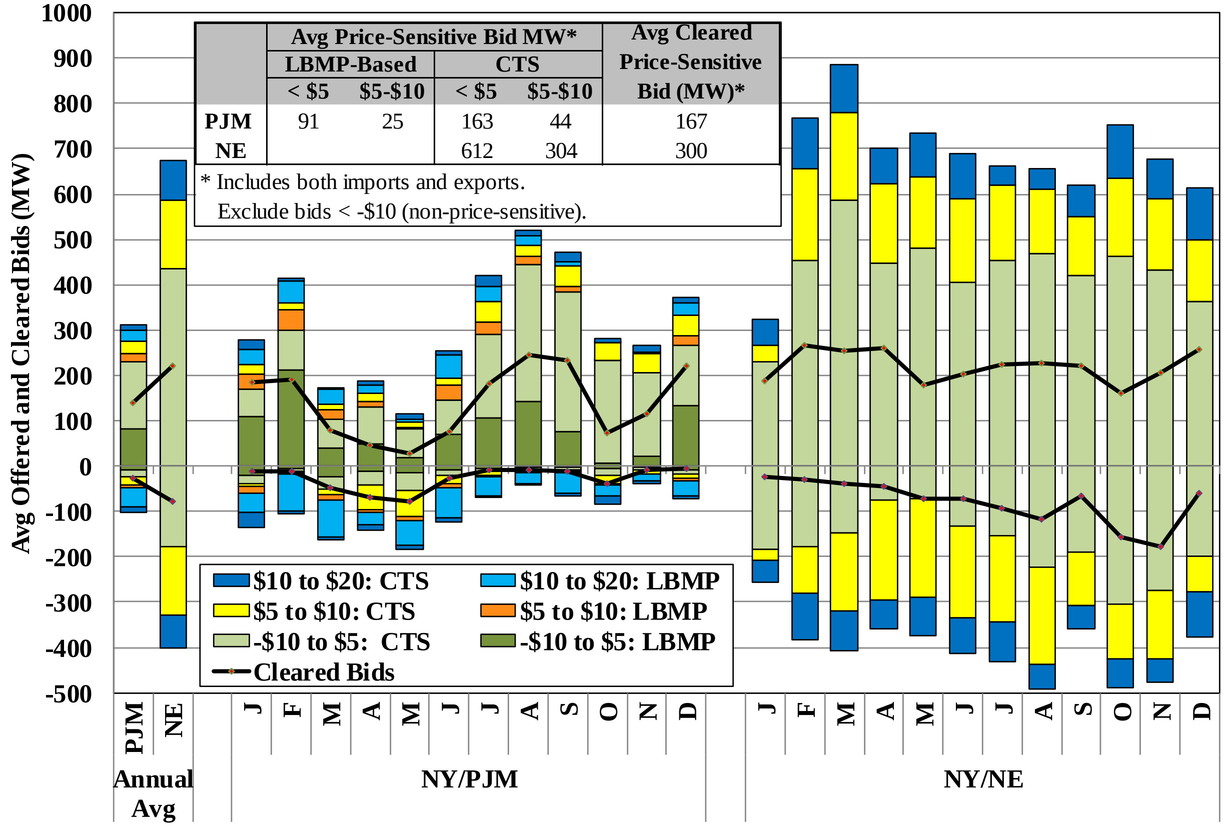

Figure A-64: Transaction Profitability at the Primary PJM and NE Interfaces

The second analysis examines the profitability of scheduled transactions at the two CTS-enabled interfaces. In the bottom portion of Figure A-64, the column bars indicate the profitability spread of the middle two quartiles (i.e, 25 to 75 percentile) in 2018. 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 three groups:

- *Day-ahead* – Transactions scheduled in the day-ahead market with no changes in the real-time market (i.e., day-ahead schedules equal real-time schedules);
- *Real-time* – Transactions not offered or scheduled in the day-ahead market but scheduled in the real-time market (i.e., day-ahead schedules are zero but real-time schedules are not zero); and
- *Day-ahead Schedule with Real-Time Adjustment* – Transactions scheduled in the day-ahead market and schedule adjusted in the real-time market (i.e., day-ahead schedules are higher or lower than real-time schedules).[291]

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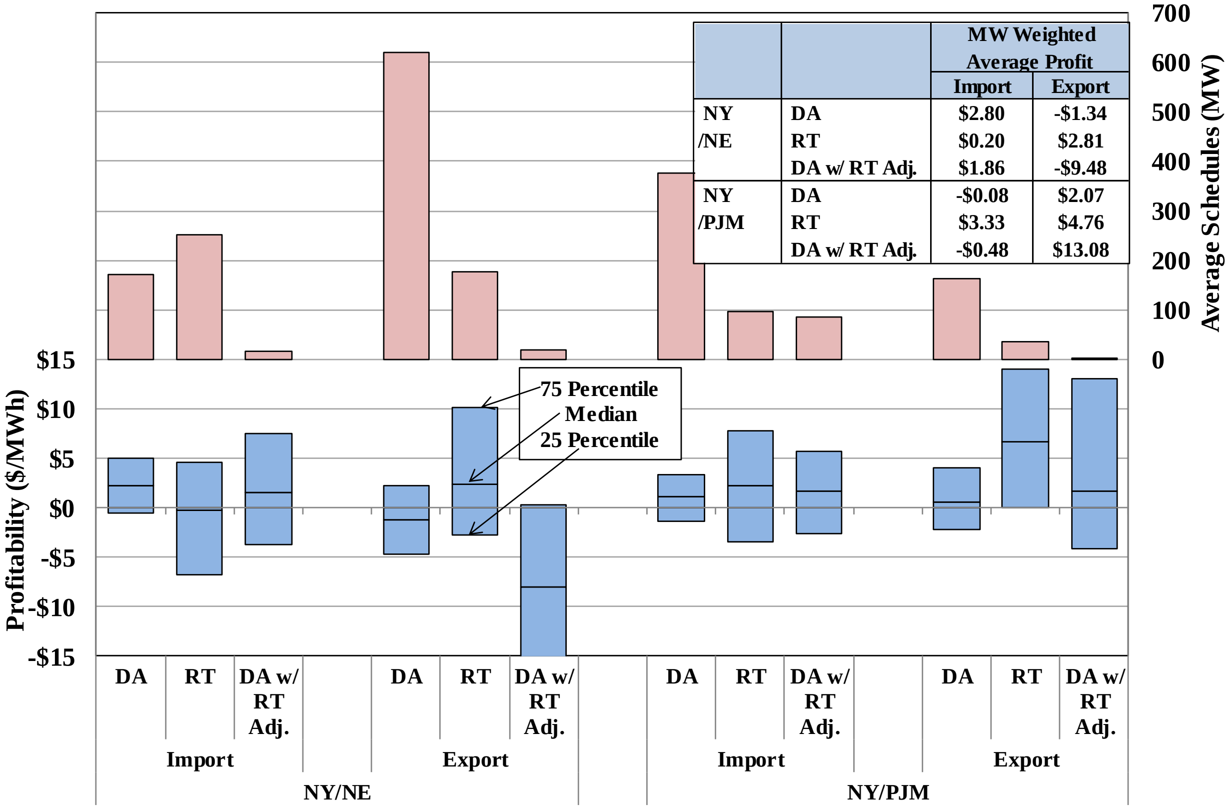
291 However, we exclude virtual imports and exports from the evaluation. These have a non-zero day-ahead schedule but do not bid/offer in real-time.

The bars in the top portion of the figure show the average quantity of scheduled transactions for each category in 2018 and the inset table summarizes the annual average profit.

Figure A-64: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2018



		MW Weighted Average Profit	
		Import	Export
NY /NE	DA	$2.80	-$1.34
	RT	$0.20	$2.81
	DA w/ RT Adj.	$1.86	-$9.48
NY /PJM	DA	-$0.08	$2.07
	RT	$3.33	$4.76
	DA w/ RT Adj.	-$0.48	$13.08

Table A-5: 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 previous 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.[292]

292 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.

Table A-5 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2018. 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.[293]
  - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled, and/or scheduled in the inefficient direction. This estimates the portion of savings that inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors. [294]
  - Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
    - Real-time Curtailment[295] - 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.

293 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 298.

294 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.

295 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).

   - Interface Ramping[296] - 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-66). 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[297,298] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.
- 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.

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296 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).

297 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).

298 The marginal cost of production is estimated from LBMPs that result from scheduling a transaction, but the marginal cost of production varies as the interface schedule is adjusted. For example, if 100 MW is scheduled to flow from PJM or NE to NYISO, reducing the price spread between markets from $12/MWh to $5/MWh, our unadjusted production cost savings estimate from the transaction would be $500/hour (= 100 MW x $5/MWh). However, if the change in production costs was linear in this example, the true savings would be $850/hour (= 100 MW x Average of $5 and $12/MWh). We make a similar adjustment to our estimate of marginal cost of production assuming that: a) the supply curve was linear in all three markets; b) at the NY/PJM border, a 100 MW movement in the supply curve changes the marginal cost by 7.5 percent of NY LBMP in the New York market and 2.5 percent of PJM LBMP in the PJM market; and c) at the NY/NE border, a 100 MW movement in the supply curve changes the marginal cost by 15 percent of NY LBMP in the New York market and 5 percent of NE LBMP in the NE market, .

Table A-5: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and New England Interfaces, 2018

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			67%	10%	**77%**	53%	12%	**65%**
Average Flow Adjustment (MW)	Net Imports		14	6	**13**	16	7	**14**
	Gross		90	109	**93**	67	95	**72**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$3.4	$3.0	**$6.3**	$1.6	$3.1	**$4.8**
	Net Over-Projection by:	NY	-$0.2	$0.2	**-$0.01**	-$0.2	-$0.6	**-$0.8**
		NE or PJM	$0.1	-$0.4	**-$0.3**	-$0.5	-$2.7	**-$3.1**
	Other Unrealized Savings		-$0.2	-$0.3	**-$0.5**	-$0.1	-$0.1	**-$0.1**
	Actual Savings		$3.1	$2.4	**$5.5**	$0.9	-$0.2	**$0.7**
Interface Prices ($/MWh)	NY	Actual	$30.56	$91.38	**$38.48**	$27.15	$79.23	**$36.49**
		Forecast	$31.64	$71.58	**$36.85**	$28.14	$64.86	**$34.72**
	NE or PJM	Actual	$32.08	$82.37	**$38.63**	$27.73	$81.80	**$37.43**
		Forecast	$31.20	$75.00	**$36.90**	$27.79	$72.25	**$35.76**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.08	-$19.80	**-$1.64**	$0.99	-$14.36	**-$1.77**
		Abs. Val.	$3.68	$46.78	**$9.30**	$3.47	$36.69	**$9.42**
	NE or PJM	Fcst. - Act.	-$0.89	-$7.37	**-$1.73**	$0.07	-$9.54	**-$1.66**
		Abs. Val.	$4.03	$31.19	**$7.57**	$3.99	$54.34	**$13.02**

Figure A-65 & Figure A-66: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-65 shows the cumulative distribution of forecasting errors in 2018. 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. The figure 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-66 illustrates this with example curves. [299] 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.

299 The two curves are forecasted supply curves used in the market on January 5, 2016.

Figure A-65: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2018

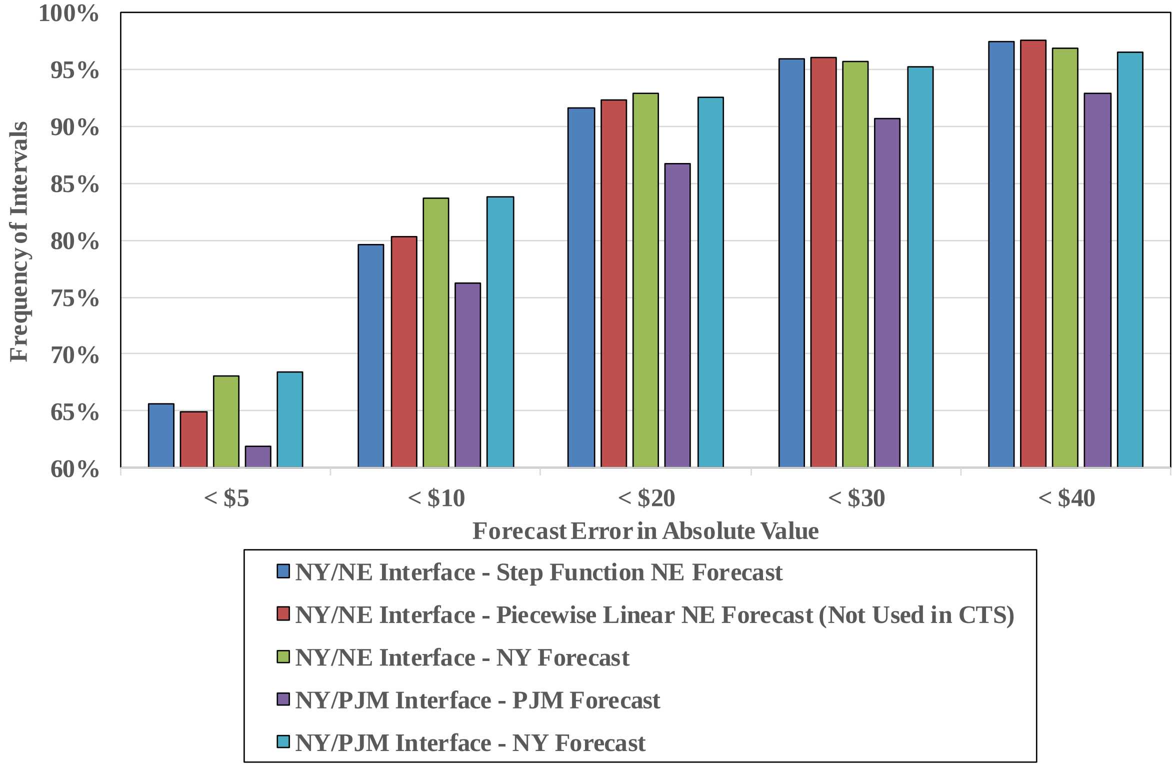
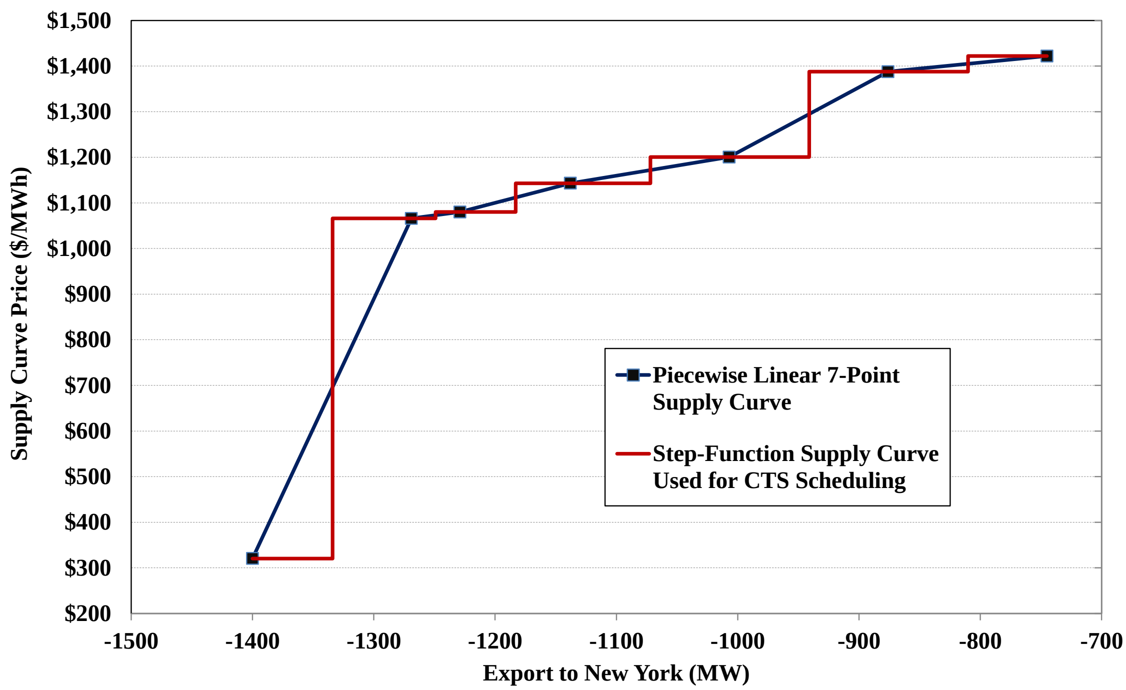


Figure A-66: Example of Supply Curve Produced by ISO-NE and Used by RTC



<u>Key Observations: Evaluation of Coordinated Transaction Scheduling</u>

- In spite of improved participation in CTS at the primary PJM interface over the last two years, the average amount of price-sensitive bids (including both CTS and LBMP-based) submitted at the primary PJM interface was still significantly lower than at the primary New England interface (see Figure A-63).
  - In 2018, an average of 612 MW (including both imports and exports) were offered between -$10 and $5/MWh at the NY/NE interface, while only 254 MW were offered at the primary NY/PJM interface.
  - Likewise, the amount of cleared price-sensitive bids at NY/NE interface nearly doubled the amount cleared at the NY/PJM interface.
  - These results indicate more active participation at the NY/NE interface. As a result:
    - The interchange schedules were adjusted (from our estimated hourly schedule) more frequently at the NY/NE interface (77 percent of intervals) than at the NY/PJM interface (65 percent of intervals); and
    - The projected production cost saving at the scheduling time was higher at the NY/NE interface ($6.3 million) than at the NY/PJM interface ($4.8 million). (see Table A-5)
- The differences between the two CTS processes are largely attributable to the large fees that are imposed at the NY/PJM interface, while there are no substantial transmission service charges or uplift charges on transactions at the NY/NE interface.
  - The NYISO charges physical exports to PJM at a rate typically ranging from $6 to $7/MWh, while PJM charges physical imports and exports at a rate less than $2/MWh, and 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.
    - These charges are a significant economic barrier to efficient scheduling through the CTS process, since large and uncertain charges deter participants from submitting price-sensitive CTS bids at the NY/PJM border.
  - On the ISO-NE border, most of the cleared transactions were offered at less than $5/MWh (see Figure A-63) and their average profit (including both imports and exports) was slightly more than $1/MWh in 2018 (see Figure A-64).
    - However, on the PJM border, given that the NYISO charges to exports are often expected to exceed $5/MWh, it is not surprising that almost no CTS export bids were offered at less than $5/MWh (see Figure A-63) and the average profit (not

including fees) for real-time exports was close to $5/MWh (the median profit was close to $7/MWh, see Figure A-64).[300]

- This demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquidity of the CTS process.
- We believe much of this large difference in the performance of the two CTS processes is explained by charges that are imposed on the CTS transactions at the PJM interface and therefore recommend eliminating these charges.

- The overall performance of CTS at the New England border improved modestly as the actual production cost savings rose from $4.8 million in 2017 to $5.5 million in 2018.
  - This improvement was partly due to better price forecasting at the NY/NE border, where NYISO forecast error improved from 25 percent in 2017 to 24 percent in 2018 and ISO-NE forecast error improved from 24 percent to 20 percent.
  - However, the actual production cost savings at the PJM border did not change much ($0.6 million in 2017 vs $0.7 million in 2018).
    - Although NYISO forecast error at the PJM border fell from 28 percent in 2017 to 26 percent in 2018, PJM forecast error increased from 27 percent to 35 percent.
    - Of all price forecasts at the two CTS interfaces, the performance of PJM price forecasts were the worst in 2018. (see Figure A-65).
- Our analyses also show that projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were larger.
  - In 2018, over 80 percent of projected production cost savings were realized when the forecast errors were moderate, while only 36 percent were realized when forecast errors were larger, which undermined the overall efficiency of CTS. (see Table A-5).
  - Therefore, improvements in the CTS process should focus on identifying sources of forecast errors. The following sub-section evaluates factors that contribute to forecast errors by the NYISO.

D. 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. The following analyses: (a) evaluate the magnitude and patterns of forecast errors and (b) examine how the assumptions regarding key inputs affect the accuracy of RTC's price forecasting.

[300] Most of the day-ahead exports to PJM were scheduled by participants with physical contract obligations and were not necessarily sensitive to these export fees.

Figure A-67 & Figure A-68: Patterns in Differences between RTC Forecast Prices and RTD Prices

Figure A-67 shows a histogram of the resulting differences in 2018 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 RTC LBMP minus the average RTD LBMP, the median of the RTC LBMP minus the RTD LBMP, and the mean absolute difference between the RTC and RTD LBMPs. LBMPs are shown at the NYISO Reference Bus location at the quarter-hour intervals for both RTC and RTD.

Figure A-67: Histogram of Differences Between RTC and RTD Prices and Schedules
2018

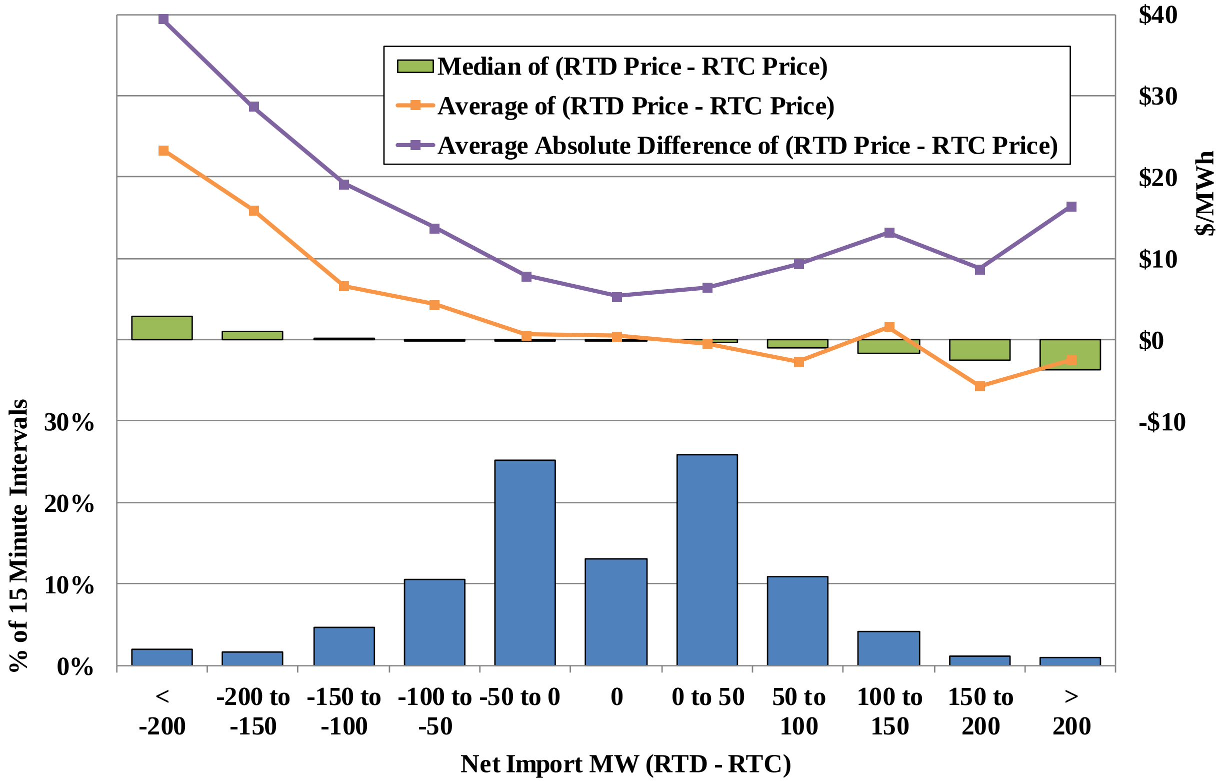


Figure A-68 summarizing these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels that exceed 100 MW by time of day, while the upper portion summarizes 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 by time of day.

Figure A-68: Differences Between RTC and RTD Prices and Schedules by Time of Day
2018

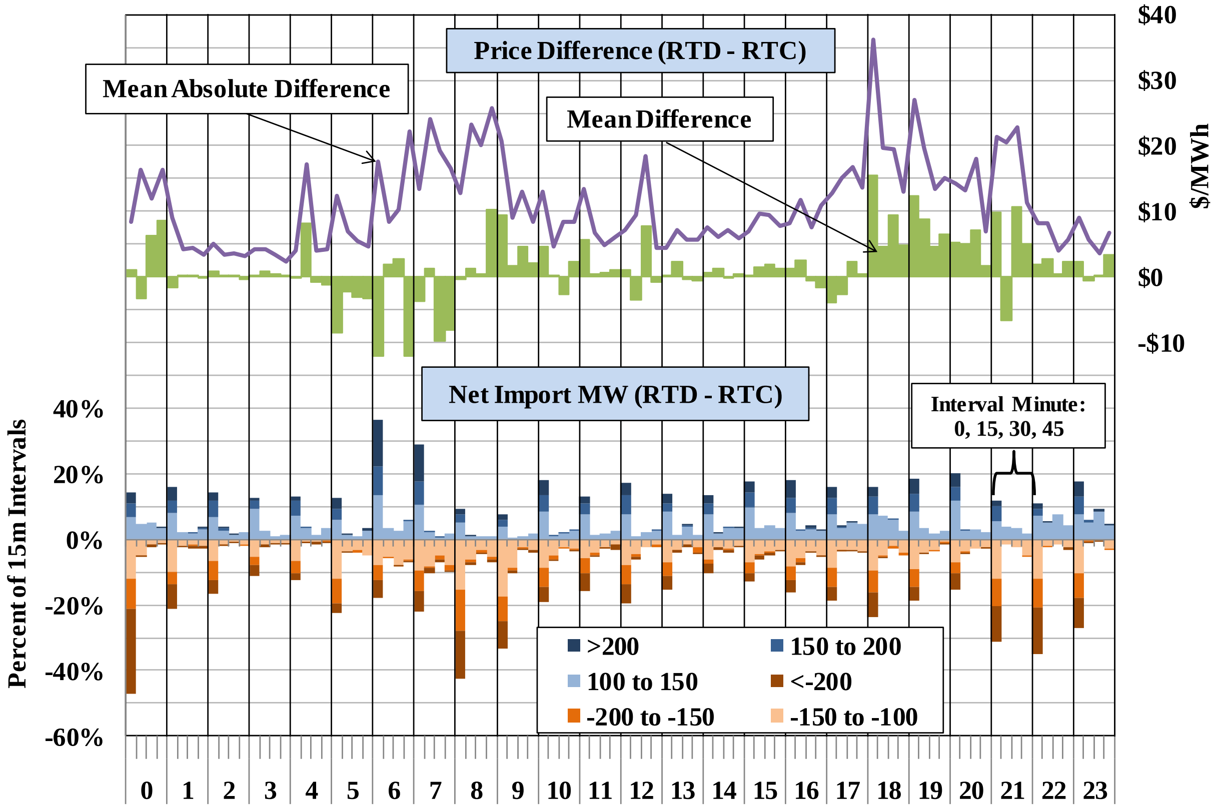


Figure A-69 to Figure A-72: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-69 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. While inconsistent ramp profile assumptions are not the only source of inconsistent RTC and RTD results, they illustrate how inconsistent modeling assumptions can lead to inconsistent pricing outcomes.

In RTD, the assumed level of net imports is based on the actual 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-69: Illustration of External Transaction Ramp Profiles in RTC and RTD

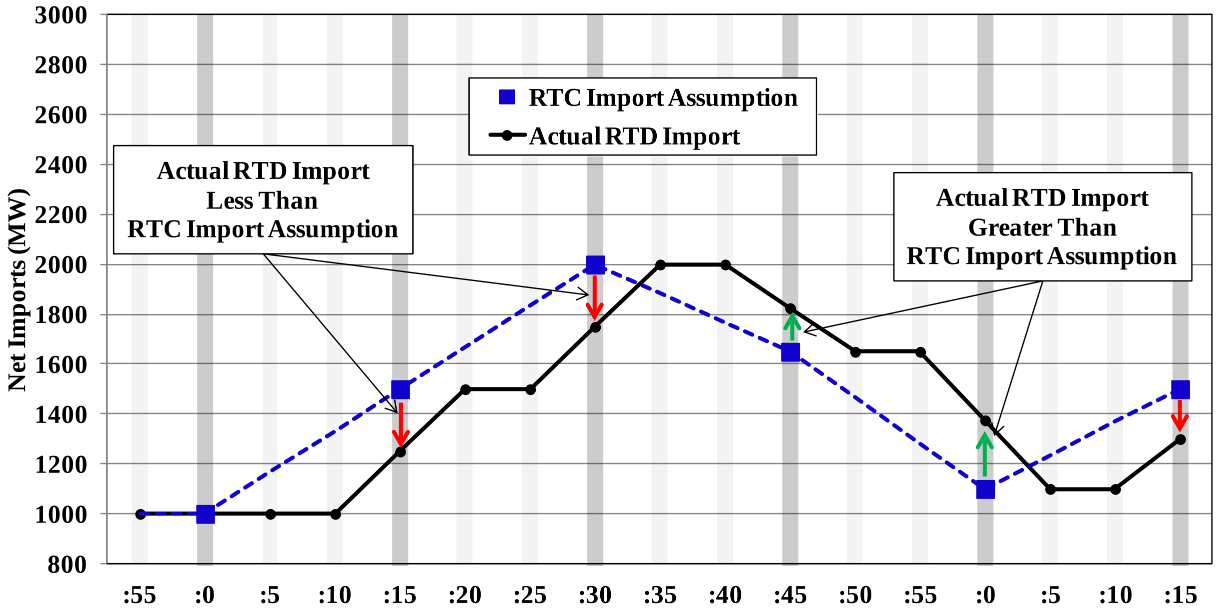


Figure A-70 to Figure A-72 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it 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).[301]

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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301 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:

$$Metric_i = (NetInjectionMW_{i,RTC} – NetInjectionMW_{i,RTD}) * (Price_{i,RTC} – Price_{i,RTD})$$ [302]

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

[302] 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.[303]

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.

303 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, B, C, 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-69.

Figure A-70 summarizes the RTC/RTD divergence metric results for detrimental factors in 2018, while Figure A-71 provides the summary for beneficial factors. Figure A-72 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-70: Detrimental Factors Causing Divergence between RTC and RTD
2018

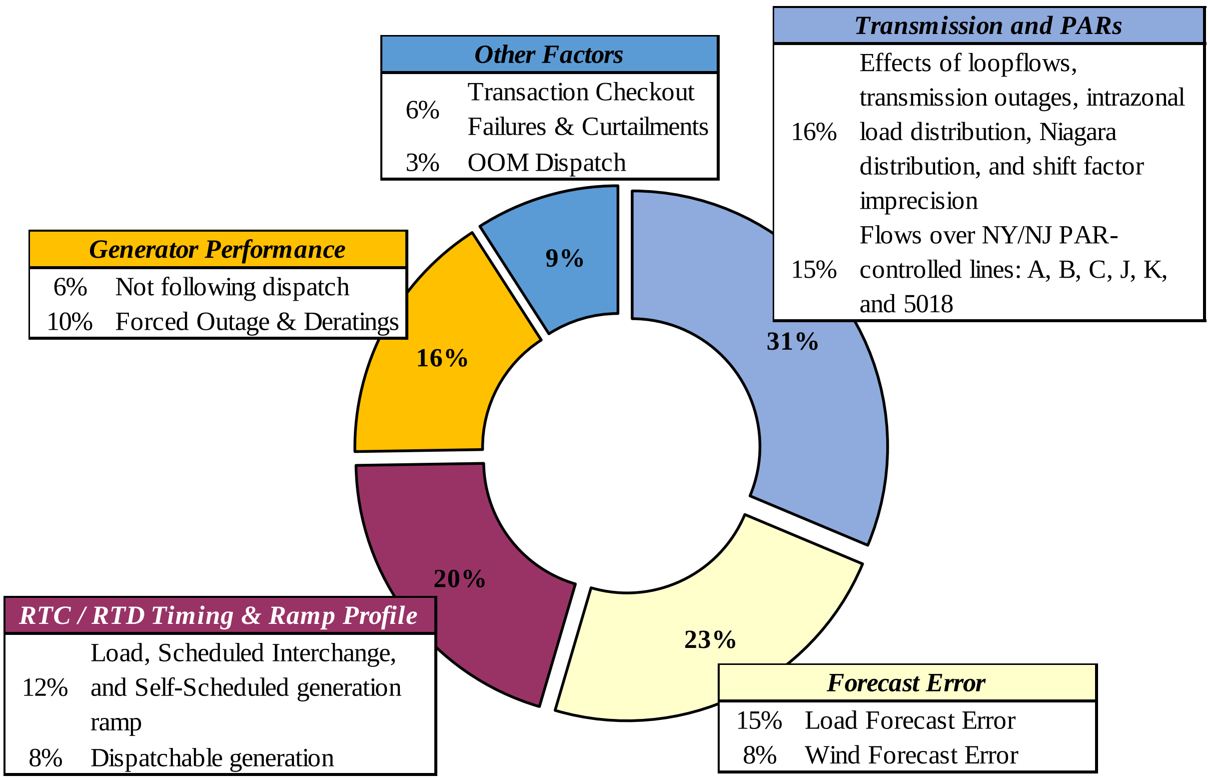


Figure A-71: Beneficial Factors Reducing Divergence between RTC and RTD
2018

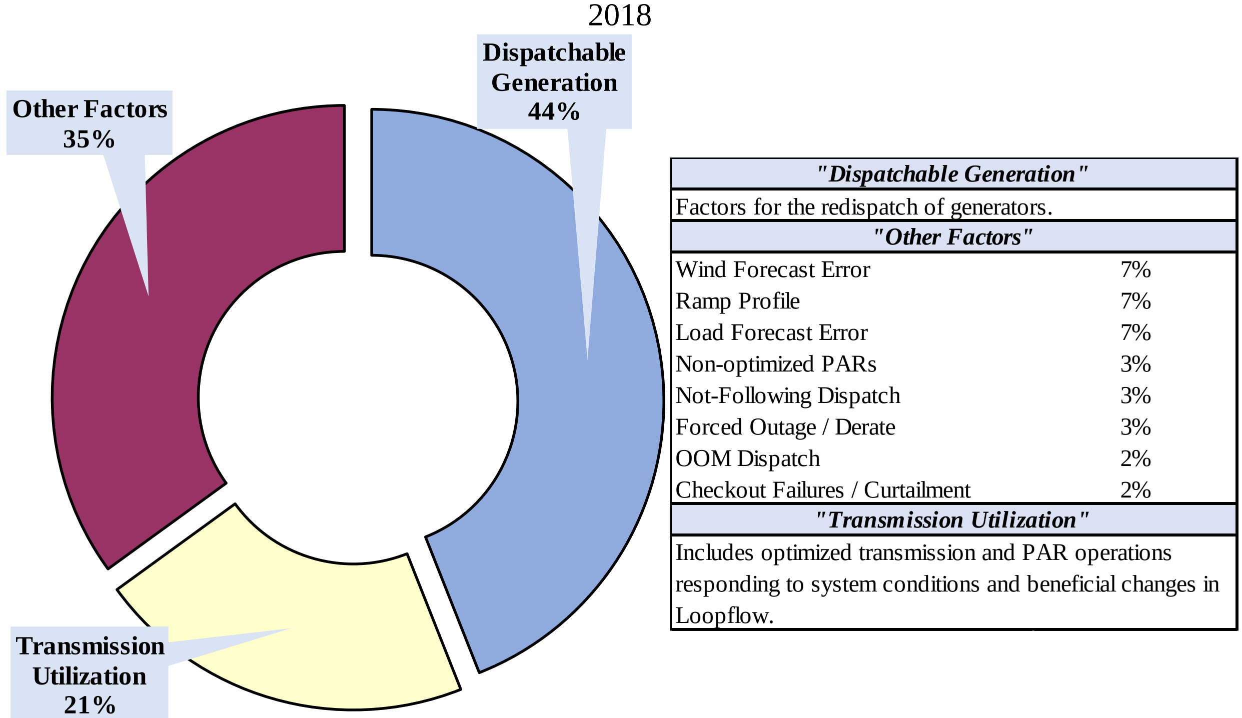
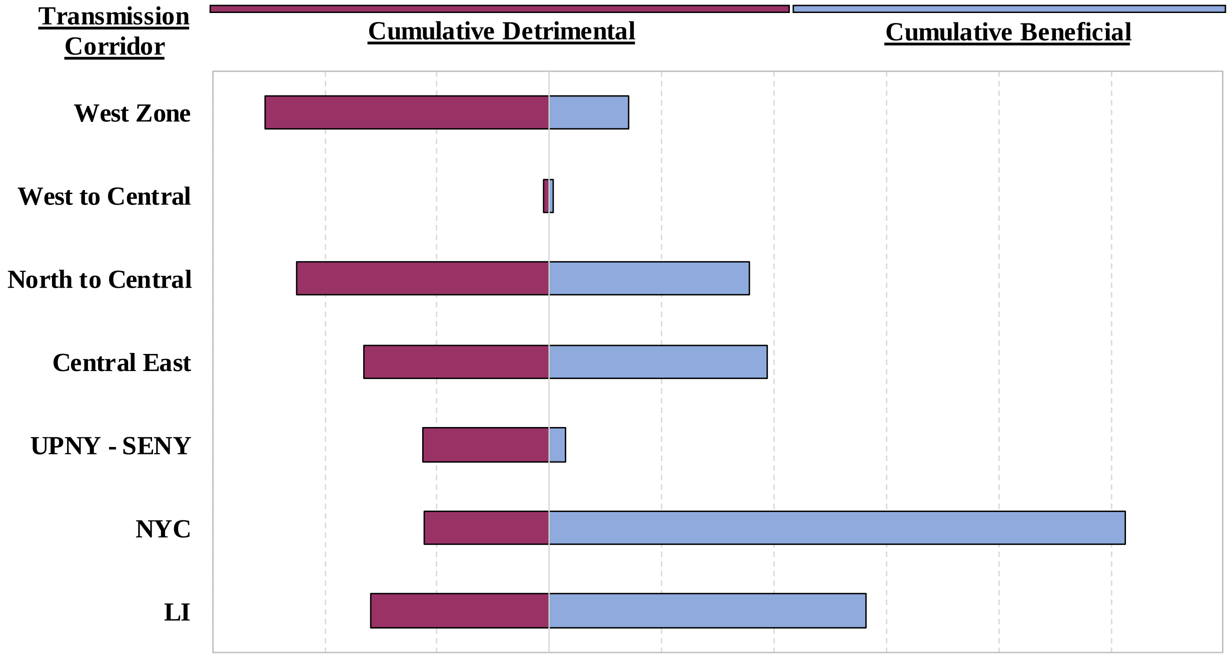


Figure A-72: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2018



Key Observations: Evaluation of Coordinated Transaction Scheduling

- The evaluations correlating RTC price forecast error with the magnitude of changes in scheduled interchange (which are shown in Figure A-67 and Figure A-68) suggest that inconsistencies in the ramp assumptions that are used in RTC and RTD (which are illustrated in Figure A-69) contribute to forecasting errors on the NYISO side of the interfaces.
  - RTC price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions (see Figure A-67 and Figure A-68). This deters large schedule changes that might otherwise be economic, thereby reducing the efficiency gains from CTS.
  - However, it is evident from Figure A-68 that there must be other very significant drivers of divergence not explained by this particular inconsistency between RTC and RTD.
- In the assessment of detrimental factors, we find the following were the primary causes of divergence in 2018, which were generally similar to those identified for 2017:
  - 31 percent from changes between RTC and RTD in network modeling, including the modeling of the transmission network and PAR-controlled lines.
    - The largest component was the flows on PAR-controlled lines between NYISO and PJM (i.e., the A, B, C, J, K, and 5018 lines), which are assumed to remain at the most recent telemetered value plus an adjustment for changes in interchange between NYISO and PJM. However, the actual flows over these lines are

affected by the re-dispatch of resources in PJM and NYISO as well as when taps are taken to relieve congestion in the market-to-market congestion management process. The detrimental contribution of these PARs fell in 2018, primarily because the B and C lines were OOS almost during the entire year.

- Other significant contributions to this category include variations in transfer capability available to NYISO-scheduled resources that result primarily from: a) transmission outages; b) changes in loop flows; and c) inaccuracies in the calculation of shift factors for NYISO resources, which are caused by the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch, inaccurate modeling of the Niagara generator, and changes in the distribution of load within a zone.

- 23 percent from errors in forecasting of load and production from wind turbines.
- 22 percent from changes by a market participant or another control area, which are generally outside the NYISO's control, including:
  - 16 percent from generators experiencing a derating, forced outage, or not following dispatch; and
  - 6 percent from transaction checkout failures and curtailments.
- 20 percent from inconsistencies in assumptions related to the timing of the RTC evaluation versus the RTD evaluation. This includes inconsistencies in the ramp profiles assumed for external interchange (which is depicted in Figure A-69), load, self-scheduled generators, and dispatchable generators.

- In the assessment of beneficial factors, we find the following were the primary factors that helped reduce divergence in 2018, similar to 2017 as well:
  - 44 percent from dispatchable generation, which is expected since many generators are flexible and respond efficiently to changes in system conditions.
  - 24 percent from changes between RTC and RTD in network modeling, including the modeling of the transmission network and PAR-controlled lines. Most of this benefit results from the flexibility of the transmission system to respond to changes in system conditions between RTC and RTD. Sometimes, random variations in transfer capability contribute to this beneficial category as well.
- In the detailed summary of transmission network modeling issues, we find that transmission facilities in some regions generally exhibited detrimental contributions while others exhibited significant beneficial contributions.
  - The following regions generally exhibited detrimental contributions:
    - West Zone – Loop flows around Lake Erie are the primary driver of detrimental contributions in this category. Large variations in loop flows around Lake Erie lead to transmission bottlenecks near the Niagara plant. Reductions in available transfer capability after RTC lead to higher congestion costs in RTD, while

increases in available transfer capability after RTC lead to lower congestion costs in RTD.

- UPNY-SENY – The primary driver was TSA operations, which impose large reductions in transfer capability across the interface. However, these are often not in-sync between RTC and RTD.

- New York City and Long Island generally exhibited beneficial contributions.
- These tend to exhibit beneficial contributions because of the flexibility of the model to adapt to system conditions. These areas also benefit from having a large number of PAR-controlled lines that are normally used to minimize congestion.

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 2018:

- *Market Operations During the 2017/18 Cold Spell* – This sub-section evaluates the performance of the energy and operating reserve markets under severe cold weather.
- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *Performance of Operating Reserve Providers* – This sub-section 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 sub-section evaluates the operation of PAR-controlled lines under market-to-market coordination ("M2M") between PJM and the NYISO.
- *Operation of Controllable Lines* – This sub-section evaluates the efficiency of real-time flows across controllable lines more generally.
- *Real-Time Transient Price Volatility* – This sub-section evaluates the factors that lead to transient price volatility in the real-time market.
- *Pricing Under Shortage Conditions* – Efficient operations better enable the existing resources to satisfy demand and maintain reliability under peak demand conditions, and they provide efficient signals for investment. We evaluate three types of shortage conditions: (a) shortages of operating reserves and regulation, (b) transmission shortages, and (c) reliability demand response deployments.
- *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.

- *Out-of-Merit Dispatch* – Out-of-merit ("OOM") dispatch is necessary to maintain reliability when the real-time market does not provide incentives for suppliers to satisfy certain reliability requirements or constraints. Like supplemental commitment, OOM dispatch may indicate the market does not provide efficient incentives.

- *BPCG Uplift Charges* – This sub-section evaluates BPCG uplift charges resulted primarily from supplemental commitment and out-of-merit dispatch.

A. Market Operations During the 2017/18 Cold Spell

Although the NYISO capacity market is designed to ensure sufficient installed capacity to maintain reliability during severe summer conditions, it currently does not have long-term market mechanism that is specifically designed to ensure that generators will have sufficient fuel to maintain reliability during severe winter conditions. The NYISO relies heavily on the day-ahead and real-time energy and ancillary services markets to provide incentives for generators to line-up their fuel supplies necessary to be available when needed.

Therefore, it is important to assess whether the day-ahead and real-time markets are functioning efficiently during severe winter weather conditions to ensure that suppliers have appropriate incentives to be available. The period from late-December 2017 to early-January 2018 provided an opportunity to evaluate the performance of the energy and operating reserve markets under severe cold weather.

Figure A-73: Utilization of Oil-Fired and Dual-Fuel Capacity During the Cold Spell

This subsection evaluates the use of oil-fired and dual-fuel resources in Eastern New York during the Cold Spell from December 27, 2017 to January 9, 2018. We estimate the amount of capacity that would have been economic based on the variable cost of generating from fuel oil, assuming no logistical, mechanical, or environmental limitations. For economic oil-capable resources, we identify factors that limited usage on each day during this period. This assessment provides key insight about how efficient markets should affect the availability of generation with firm fuel supply during periods of extreme natural gas scarcity.

Figure A-73 shows the estimated generation that would have been economic to burn oil based on day-ahead and real-time clearing prices during this period.[304] The figure shows the capacity in the following categories:

- Actual output, including oil-fired generation and gas-fired generation;

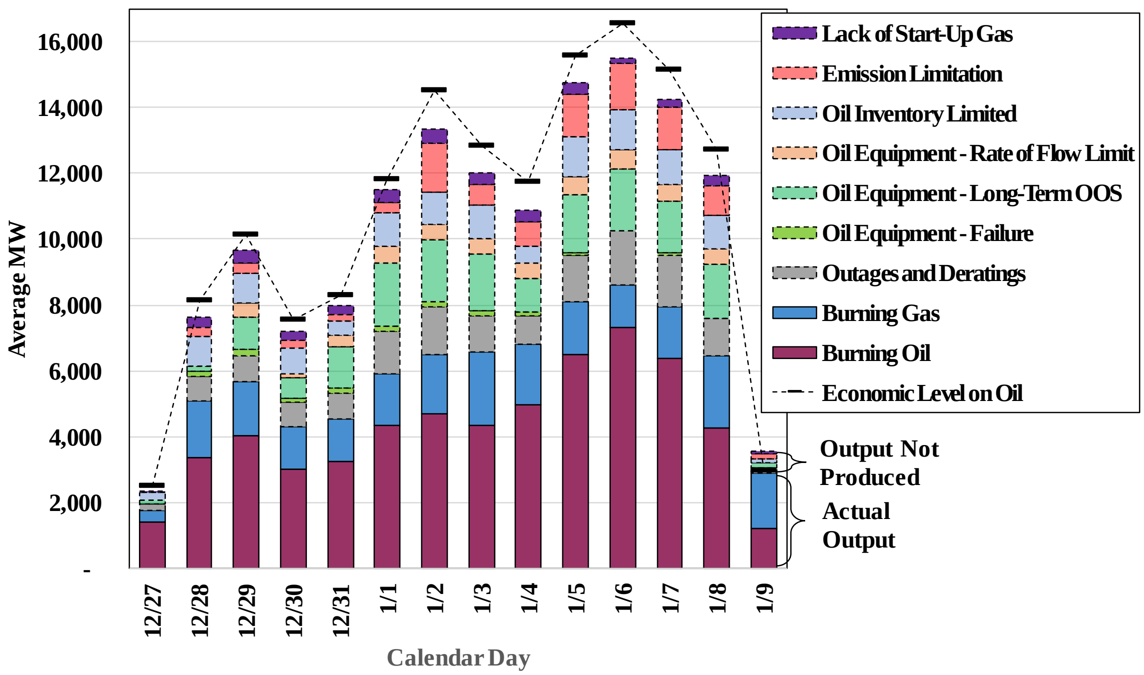
- The amount of economic oil-fired generation that was unavailable because of:

304 We assume economic commitment of fast-start generation is done in accordance with real-time prices while economic commitment of slow-start generation is done in accordance with day-ahead prices.

- Outages and deratings;
- Oil equipment long-term OOS – mothballed or decommissioned oil equipment;
- Oil equipment rate of fuel flow is limited;
- Oil equipment failures – short-term equipment outages;
- Emission limitations;
- Oil inventory limitations; [305] and
- Lack of gas to start up.

On each day, there was a small amount of capacity that appeared to be economic but which we were unable to categorize. (This is indicated by the difference between the top of the stacked bars and the estimated economic level on oil.)

Figure A-73: Utilization of Oil-Fired and Dual-Fuel Capacity
Eastern New York During the 2017/18 Cold Spell



Key Observations: Use of Oil-Fired and Dual-Fuel Capacity During the Cold Spell

- During the Cold Spell from December 28, 2017 to January 8, 2018, average actual oil-fired production was only about 39 percent of the Eastern New York capacity that we estimate would have been economic to burn fuel oil on these days.

305 For each generator whose economic oil-fired output exceeded its fuel inventory, we calculated the daily inventory limitation assuming the it will burn the same daily amount of oil for the remainder of the period.

- To the extent these units were not burning oil, it was primarily due to:
  - Long-term outages of equipment for burning oil, accounting for 1.4 GW of unutilized capacity;
  - Outages and deratings, which averaged 1.1 GW;
  - Inventory-limited units, accounting for 0.9 GW of unutilized capacity;
  - Emission-limited units, accounting for 0.8 GW of unutilized capacity; and
  - Units burning natural gas, which averaged 1.7 GW. Approximately one-quarter of the gas burn was to manage emission limitations.
- Inventory limitations, outages and deratings, and oil equipment failures accounted for a large share of unutilized oil-fired output that appeared economic.
  - Generators that have fuel while in a forced outage are no more valuable than generators without fuel.
  - This underscores the importance of providing efficient day-ahead and real-time price signals so that suppliers are appropriately motivated not only to procure fuel, but also to maintain their units in a reliable condition.

B. Efficiency of Gas Turbine Commitments

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.

The scheduling of energy and ancillary services is co-optimized, which is beneficial for several reasons. First, co-optimization reduces production costs by efficiently reallocating resources to provide energy and ancillary services every five minutes. Second, the market models are able to incorporate the costs of maintaining ancillary services into the price of energy by co-optimizing

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.

energy and ancillary services. This is important during periods of acute scarcity when the demand for energy and the ancillary services requirements compete for supply. Third, demand curves rationalize the pricing of energy and ancillary services during shortage periods by establishing a limit on the costs that can be incurred to maintain reserves and regulation. This also provides an efficient means of setting prices during shortage conditions. The use of demand curves during shortage conditions is discussed further in subsection G.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of gas turbines, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it leads to depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section evaluates the efficiency of real-time commitment and scheduling of gas turbines.

Figure A-74: Efficiency of Gas Turbine Commitment

Figure A-74 measures the efficiency of gas turbine commitment by comparing the offer price (energy plus start-up costs amortized over the initial commitment period) to the real-time LBMP over the unit's initial commitment period. When these decisions are efficient, the offer price components of committed gas turbines are usually lower than the real-time LBMP. However, when a gas turbine that is committed efficiently is close to the margin, it is possible for the offer price components to be greater than the LBMP. Gas turbines with offers greater than the LBMP can be economic for the following reasons:

- Gas turbines that are started efficiently and that set the LBMP at their location do not earn additional revenues needed to recover their start-up offer; and

- Gas turbines that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period.

Therefore, the following analysis tends to understate the fraction of decisions that were economic. Figure A-74 shows the average quantity of gas turbine capacity started each day in 2018. These are broken into the following categories according to the sum of the offer price components and the real-time LBMP over the initial commitment period:

- Offer < LBMP (these commitments were clearly economic);

- Offer > LBMP by up to 25 percent;

- Offer > LBMP by 25 to 50 percent; and

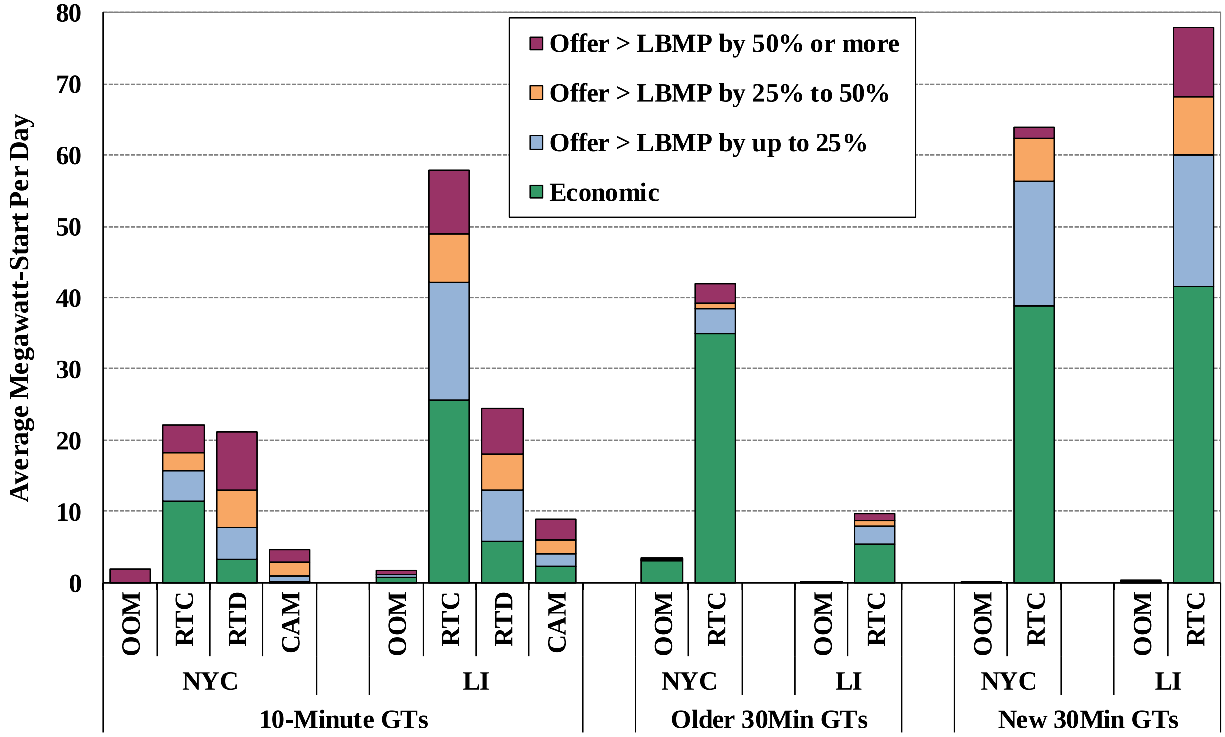
- Offer > LBMP by more than 50 percent.

Starts are shown separately for 10-minute gas turbines, older 30-minute gas turbines, and new 30-minute gas turbines. Starts are also shown separately for New York City and Long Island,

and based on whether they were started by RTC, RTD, RTD-CAM,[308] or by an out-of-merit (OOM) instruction.

The real-time market software currently uses a two-pass mechanism for the purpose of dispatching and pricing.[309] The first pass is a physical dispatch pass, which produces physically feasible base points that are sent to all resources. In this pass, the inflexibility of the gas turbines are modeled accurately with most of these units being "block loaded" at their maximum output levels once turned on. The second pass is a pricing pass, which treats gas turbines as flexible resources that can be dispatched between zero and the maximum output level and produces LBMPs for the market interval.

Figure A-74: Efficiency of Gas Turbine Commitment
2018



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.

309 The current two-pass mechanism was first implemented on February 28, 2017. This implementation eliminated the third pass from the prior three-pass mechanism and uses prices from the second pass. Previously, the additional third pass produced LBMPs for the market interval, which treated gas turbines that are not economic (i.e., dispatched at zero) in the second pass but are still within their minimum run times as inflexible (i.e., forced on and dispatched at the maximum output level). Consequently, when uneconomic gas turbines were forced on in the third pass, it led some economic gas turbines to not set the LBMP. This change in price-setting rules was a significant improvement and results in market clearing prices that are more consistent with the operational needs of the system.

Key Observations: Efficiency of Gas Turbine Commitment

- Most gas turbine commitments were made by RTC. In 2018, roughly 81 percent was committed by RTC, 17 percent by RTD and RTD-CAM, and 2 percent through OOM instructions.

- Of all gas turbine commitments in 2018, only 51 percent were clearly economic (indicated by green bars in the figure). An additional 23 percent of commitments were cases when the gas turbine offer was within 125 percent of LBMP, a significant portion of which may be efficient for the reasons discussed earlier in this subsection.
  - These statistics were similar to those calculated for 2017.

- Nonetheless, there were many commitments in 2018 when the total cost of starting gas turbines exceeded the LBMP by 25 percent or more.
  - The divergence between RTC and RTD may lead an economic RTC-committed GT to be uneconomic in RTD (see subsection IV.D for analysis of divergence between RTC and RTD).
  - In addition, the current fast-start price-setting rules do not necessarily reflect the start-up and other commitment costs of the gas turbine in the price-setting logic.
    - Therefore, we continue to recommend that the NYISO incorporate these costs into the price-setting logic. The Commission has also recognized this and ordered the NYISO to modify its pricing logic to allow the start-up costs of fast-start resources to be reflected in the prices. [310]

C. 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 sub-section 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.

Figure A-75: Average Production by GTs after a Start-Up Instruction

Figure A-75 summarizes the performance of offline GTs in responding to start-up instructions that result from in-merit commitment by RTC (excluding self-schedules). The figure reports the average performance in 2018. Performance is shown for 10-minute GTs (offering non-synchronous 10-minute reserves) and 30-minute GTs (offering non-synchronous 30-minute reserves). In the figure, the x-axis shows response rates to start-up instructions in groups with a 10-percent increment from 0 to 100 percent (i.e., measured as the GT output at 10 or 30 minutes

[310] In Docket EL18-33-000, see *Order On Paper Hearing*, issued on April 18, 2019.

after receiving a start-up instruction as a percent of its UOL).[311] The units that are in service but were never started by RTC in 2018 are placed in a separate category of "Not Started". The text boxes in the figure summarize their start-up performance in 2016 and 2017. The table in the figure compares GT start-up performance from 2016 to 2018 for GTs that were started by RTC at least once in each of the three years.

Figure A-75: Average Production by GTs after a Start-Up Instruction
Economic RTC Starts, 2018

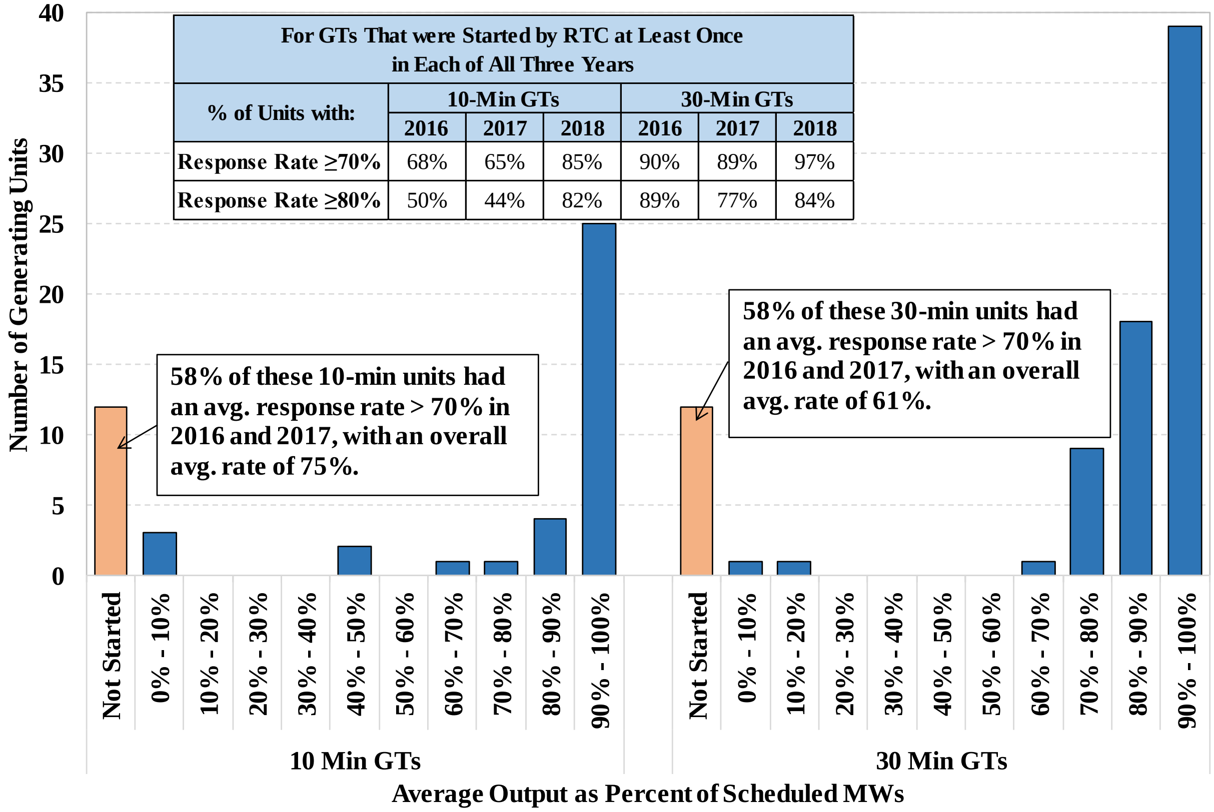


Figure A-76: Use of Operating Reserves to Manage Congestion in New York City

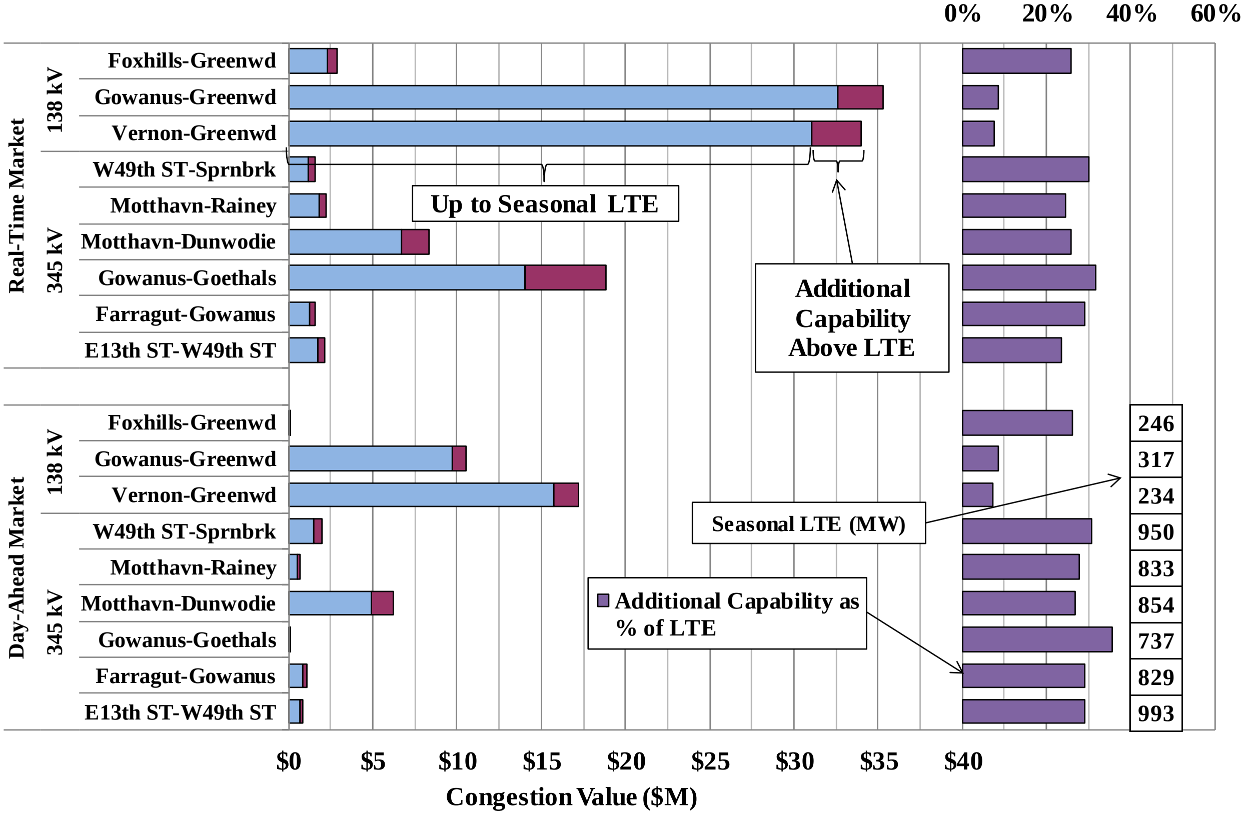
The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE. The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs. However, the service provided by these actions are not properly compensated.

Figure A-76 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 2018. The blue bars represent

311 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 70-to-80-percent group.

the congestion values measured up to the seasonal LTE ratings of the facilities.[312] The red bars represent the congestion values measured for the additional transfer capability above LTE.[313] The purple bars in the right panel shows the average additional transfer capability above LTE as a percent of LTE for these facilities.[314] The number stacks on the right side of the purple bars indicate the seasonal LTE ratings of these facilities.

Figure A-76: Use of Operating Reserves to Manage N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings, 2018



Key Observations: Performance of Operating Reserve Providers

- Although gas turbines exhibited a wide range of performance in responding to start-up instructions in recent years, GT performance improved notably in 2018.
  - For the same set of units that were started economically by RTC at least once in every year of 2016 to 2018,

312 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

313 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

314 This is calculated as (average modeled constraint limit / seasonal LTE – 100%).

    - 85 percent of 10-minute units had an average response of 70 percent or better in 2018, compared to 68 percent in 2016 and 65 percent in 2017.
    - 97 percent of 30-minute units had an average response of 70 percent or better in 2018, compared to 90 percent in 2016 and 89 percent in 2017.
  - Including all units, the average response of 10-minute units was 82 percent of the amount offered in 2018, up significantly from 66 percent in 2016 and 58 percent in 2017; while the average response of 30-minute units was 87 percent in 2018, up from 80 percent in both 2016 and 2017.
  - The overall improvement in 2018 was partly because several units with poor performance in the past were either not in service in 2018 or in service but not started in 2018.

- Units that perform poorly in response to start-up instructions tend to have higher EFORds, which leads to proportional reductions in their capacity payments. However, the EFORd calculation is not designed to reflect how well a fast-start unit responds following a start-up instruction. For example, if a 10-minute GT is producing 0 MW after 10 minutes and takes 25 minutes to start, it will be treated as having a successful service hour. Consequently, the EFORds of gas turbines are generally much lower than the average amounts not produced after start-up. In 2018:
  - For 10-minute units, the average EFORd was 6 percent during the summer months, while the average under-performance (i.e., the difference between the offered amount and the actual production) across these units was 18 percent of the amount offered after 10 minutes.
  - For 30-minute units, the average EFORd was 7 percent during the summer months, while the average under-performance across these units was just 13 percent of the amount offered after 30 minutes.
  - These discrepancies were much larger in 2016 and 2017.
- Transmission facilities in New York City can be operated above their LTE rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - The availability of post-contingency actions is important because they allow the NYISO to increase flows into load pockets in New York City and reduce overall congestion costs.
- In 2018, 73 percent (or $125 million) of real-time congestion in New York City occurred on N-1 constraints that would have been loaded above LTE after a single contingency.
  - The additional capability above LTE averaged from over 20 MW for the 138 kV constraints in the Greenwood load pocket to over 200 MW for 345 kV facilities.
  - These increases were largely due to the availability of operating reserves in New York City, but they are not compensated for this service.

  - This reduces their incentives to be available in the short term and to invest in flexible resources in the long term.
  - When the market dispatches this reserve capacity, it can reduce transfer capability in NYC, making the dispatch of these units inefficient in some cases.
- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria.[315]

D. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") commenced in January 2013. This process allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources when it is less costly for them to do so.[316] M2M includes two types of coordination:

- Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
- PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, three sets of PAR-controlled lines between New York and New Jersey can be adjusted to reduce overall congestion.[317]

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.[318]

Figure A-77: 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 2018.

315 See Recommendation #2016-1.

316 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

317 These include two Ramapo PARs that control the 5018 line, three Waldwick PARs that control the J and K lines, and three PARs that control the A, B, and C lines. However, the B and C lines have been out-of-service since January 2018 and may never be returned to service.

318 The list of pre-defined flowgates is posted at https://www.nyiso.com/reports_information in the sub-group "Notices" under "General Information".

Figure A-77 evaluates operations of these NY-NJ PARs under M2M with PJM in 2018 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:

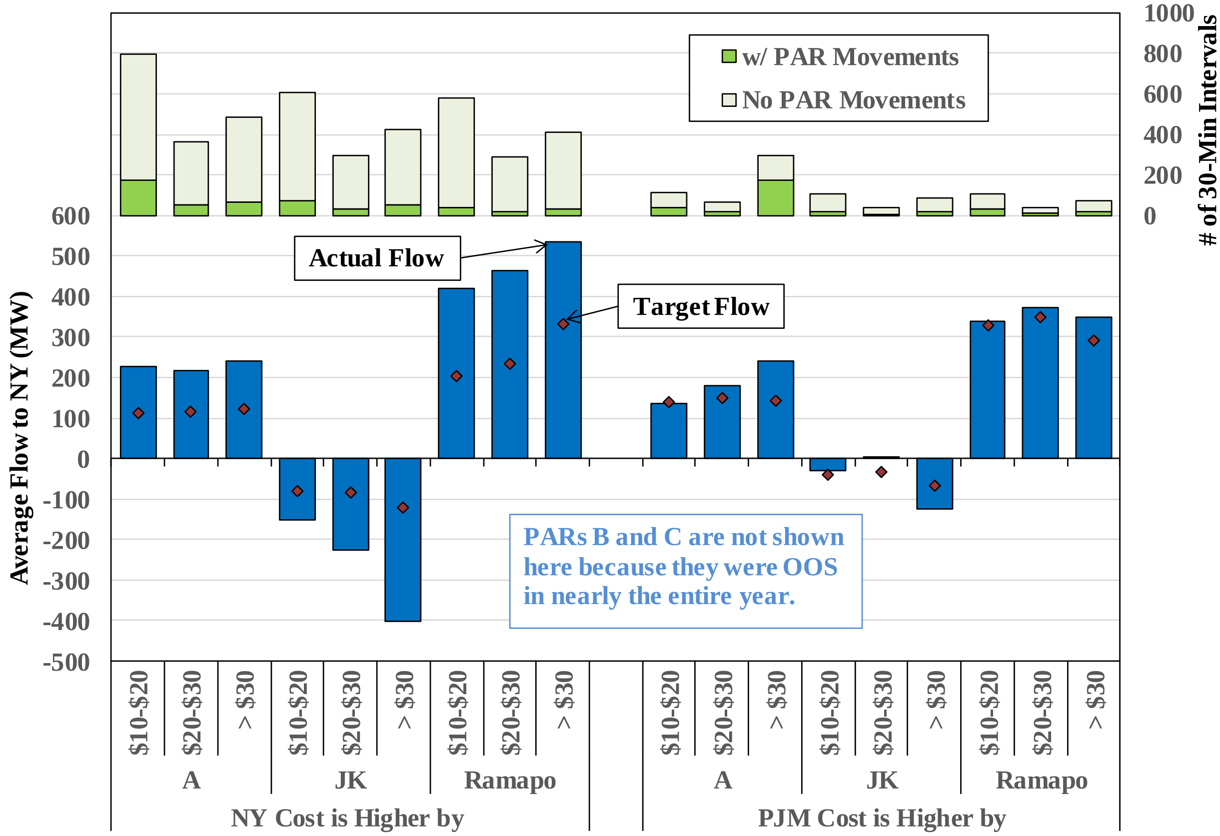
- When NY costs on relevant M2M constraints exceed PJM costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh.

- 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).

Figure A-77: NY-NJ PAR Operation under M2M with PJM
2018



Key Observations: PAR Operation under M2M with PJM

- The PAR operations under the M2M JOA with PJM has provided benefit to the NYISO in managing congestion on coordinated transmission flow gates.
  - We have observed instances of efficient M2M coordination as PARs were moved in the direction to reduce overall congestion costs in a relatively timely manner.
  - Balancing congestion surpluses frequently resulted from this operation on the Central-East interface. We estimated a total of nearly $11 million of such surpluses for 2017 and 2018 (see Section III.B in the Appendix), indicating that it reduced production costs and congestion in New York.
- Nonetheless, there were instances when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.
  - During all the 30-minute periods of 2018 when the congestion differential between PJM and NYISO exceeded $10/MWh across these PAR-controlled lines (which averaged less than five times per day), PAR taps were taken in only 17 percent of these intervals.
    - Overall, each PAR was adjusted 1 to 5 times per day on average, which was well below the operational limits of 20 taps/day and 400 taps/month.
  - Although actual flows across these PAR-controlled lines typically exceeded their M2M targets towards NYISO during these periods, flows were generally well below their seasonal normal limits (i.e., over 500 MW for each line).
  - In some cases, PAR adjustments were not taken because of:
    - Difficulty predicting the effects of PAR movements under uncertain conditions;
    - Adjustment would push actual flows or post-contingent flows close to the limit;
    - Adjustment was not necessary to maintain flows above the M2M target (even though additional adjustment would have been efficient and reduced congestion);
    - The transient nature of congestion; and
    - Mechanical failures (e.g., stuck PARs).
    - However, we lack the information necessary to determine how often some of these factors prevented PAR adjustments.
- These results highlight potential opportunities for increased utilization of M2M PARs.
  - However, the NYISO operators do not have a congestion or production cost forecasting model that can be used to determine the efficient schedule for these M2M PARs, so it will be difficult to optimize the PAR operation without a model to forecast the impacts of PAR tap adjustments in real-time.

- In Section IV.D of the Appendix, our evaluation of factors causing divergences between RTC and RTD identifies the operation of the NY-NJ PARs as a net contributor to price divergence. This is because RTC has no information related to potential tap changes. Consequently, RTC may schedule CTS imports to relieve congestion, but, if after RTC kicks-off, the operator taps the A, B, C, and 5018 PARs in response to the congestion, it often leads the imports to be uneconomic. Accordingly, we have observed a reduction in divergences between RTC and RTD that were caused by the operation of the NY-NJ PARs from 2017 to 2018 because the B and C lines were out-of-service throughout 2018. This illustrates why forecasting PAR tap adjustments would also help reduce divergences between RTC and RTD.

E. 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.[319] Such lines are analyzed in Section V.E 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 in order to reduce generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not primarily focused on reducing production costs in the day-ahead and real-time markets. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-6 and Figure A-78: 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 in order to facilitate power transfer between regions or to manage congestion within and between control areas. This sub-section evaluates efficiency of PAR operations during 2018.

Table A-6 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2018. The evaluation is done for the following eleven PAR-controlled lines:

- Two between IESO and NYISO: St. Lawrence – Moses PARs (L33 & L34 lines).

319 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.

- One between ISO-NE and NYISO: Sand Bar – Plattsburgh PAR (PV20 line).
- Six between PJM and NYISO: Two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), two Hudson-Farragut PARs (B & C lines), and one Linden-Goethals PAR (A line). These lines are currently scheduled in accordance with the M2M coordination agreement with PJM, which is discussed in sub-section D. [320]
- Two between Long Island and New York City: Lake Success-Jamaica PAR (903 line) and Valley Stream-Jamaica PAR (901 line). These lines were ordinarily scheduled to support a wheel of up to 300 MW from upstate New York through Long Island and into New York City.

For each group of PAR-controlled lines, Table A-6shows:

- 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.[321]

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.[322] For Ontario, the

320 Prior to May 1, 2017, the A, B, C, J, & K lines supported the operation of the ConEd-PSEG wheeling agreement whereby 1,000 MW was ordinarily scheduled to flow out of NYCA on the J & K lines and 1,000 MW was scheduled to flow into New York City on the A, B, & C lines.

321 For example, if 100 MW flows from Lake Success to Jamaica during 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). This is because each MW of flow saves \$10 by allowing a \$60 per MWh resource in New York City to ramp down and be replaced by a \$50 per MWh resource in Long Island. 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 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.

322 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule is considered *efficient direction*, and if the relative prices of the two regions is switched in the real-time market and the flow was reduced to 80 MW, the adjustment is shown as -20 MW and the real-time schedule adjustment is considered *efficient direction* as well.

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.

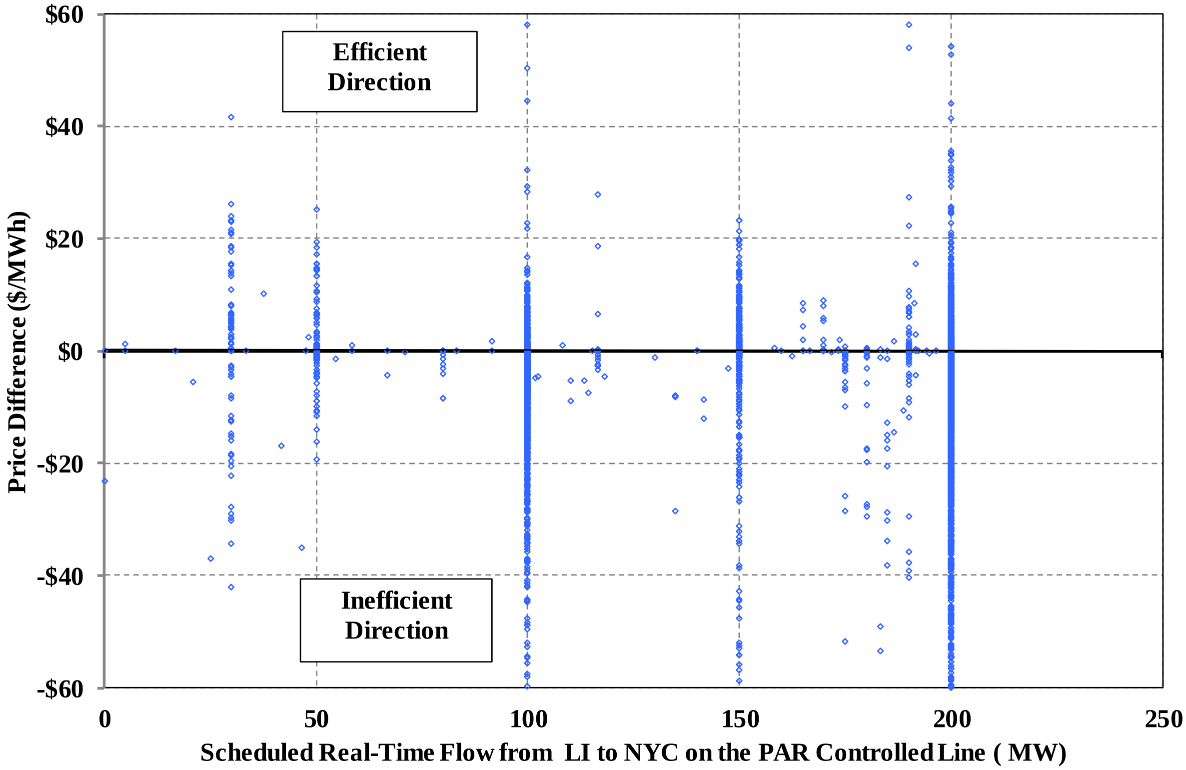
Table A-6: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines [323]
2018

	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					-30	$7.09	47%	-$2
New England to NYCA								
Sand Bar	-75	-$18.17	95%	$12	-1.6	-$17.04	55%	$0.5
PJM to NYCA								
Waldwick	-61	$1.39	45%	$0.3	-8	$1.34	50%	-$2
Ramapo	256	$2.30	73%	$8	157	$2.35	59%	$7
Goethals	120	$4.26	81%	$5	86	$0.68	53%	-$1
Long Island to NYC								
Lake Success	135	-$5.77	10%	-$8	-3	-$6.34	48%	-$0.3
Valley Stream	69	-$10.97	6%	-$8	0.04	-$10.64	46%	-$0.1

Figure A-78 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.

323 The two Hudson-Farragut PARs (i.e., the B and C PARs) are not included in the table because the two PARs were OOS in almost the entire year of 2018.

Figure A-78: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2018



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- The 901/903 lines are used to support the ConEd-LIPA wheeling agreement.[324] The scheduling across the two lines was much less efficient than other PAR-controlled lines.
  - Scheduled power across the 901/903 lines flowed in the efficient direction in only 6 to 10 percent of hours in the day-ahead market, which was much less frequent than any of other PAR-controlled lines.[325]
  - The use of the two lines increased day-ahead production costs by an estimated $16 million in 2018 because prices on Long Island were typically higher than those in New York City (particularly where the 901 and 903 lines connect in the Astoria East/Corona/Jamaica pocket, which is sometimes export-constrained).
  - In addition to increasing production costs, these transfers can restrict output from economic generators in the Astoria East/Corona/Jamaica pocket and at the Astoria Annex. Restrictions on the output of these generators sometimes adversely affects a

324 Under this agreement, the two PAR-controlled lines are used to wheel roughly half of the power on the Y50 line (from upstate to Long Island) back to New York City.

325 Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these two PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.

much wider area (e.g., when there is an eastern reserve shortage or during a TSA event).

  - Moreover, these transfers also lead to increased pollution because they require older steam turbines and gas turbines without back-end controls in Long Island to ramp up while newer combined cycle generation with selective catalytic reduction in New York City are ramped down.

- The scheduling efficiency over the PAR-controlled A, B, C, J, and K lines has improved generally following the expiration of the ConEd-PSEG wheeling agreement in May 2017 (notwithstanding the outage of the B and C lines since January 2018).
  - Although these PARs have been operated in a way more responsive to market price signals, operations over the J and K lines were much less active (see Figure A-77), resulting in less efficient scheduling than over the A line. Consequently, the J and K lines accounted for a $2 million net increase in production costs, while the A line accounted for a $4 million net reduction in production costs.
- Significant opportunities remain to improve the operation of the lines between New York City and Long Island.
  - These lines are all currently scheduled according to the terms of a long-standing contract that pre-dates open access transmission tariffs and the NYISO's markets. It would be highly beneficial to modify this contract or find other ways under the current contract to operate the lines efficiently.
  - Under the ConEd-LIPA wheeling agreement, ConEd possesses a physical right to receive power across the 901 and 903 lines. To compensate ConEd during periods when it does not receive power across these lines, ConEd should be granted a financial right that would compensate it based on LBMPs when the lines are redispatched to minimize production costs (similar to a generator). [326]

F. 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

326 The proposed financial right is described in Section III.F of the Appendix.

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 2018. 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 account for roughly 4 percent of the real-time pricing intervals in 2018, 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-7: Transient Real-Time Price Volatility

Table A-7 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2018 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, B, C, 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).[327,328] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[329] 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 – These include 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. Additionally, these result from inaccurate modeling of the Niagara plant. Different units at the Niagara plant have different shift factors, but RTD assumes a single

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327 These lines are discussed further in Subsection E.

328 M2M coordination is discussed further in Subsection D.

329 The flows over the ABC, 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.

shift factor for the entire plant for pricing and scheduling purposes.[330] When the units that respond to dispatch instructions differ from the assumption used in RTD, it may lead to changes in unscheduled flows over the constraint.

- Self-Scheduled Generator – This includes online generators that are moving in accordance with a self-schedule, resources shut-down in accordance with a self-schedule, and resources that are shut down because they did not submit a RT offer. In some cases, large inconsistencies can 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.

- 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-7, 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.

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330 The NYISO implemented an improved modeling of the Niagara Plant in December 2018, which better recognizes the impact of individual turbines on constraints. This should help greatly reduce the contribution to transient price spike in this category.

Table A-7: Drivers of Transient Real-Time Price Volatility
2018

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints		New York City Load Pockets		North to Central	
Average Transfer Limit	**n/a**		**586**		**2423**		**816**		**280**		**310**		**321**	
Number of Price Spikes	**663**		**989**		**223**		**304**		**653**		**3501**		**556**	
Average Constraint Shadow Price	**$256**		**$729**		**$368**		**$310**		**$483**		**$559**		**$520**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**168**	**62%**	**1**	**10%**	**73**	**52%**	**44**	**60%**	**8**	**57%**	**4**	**36%**	**1**	**11%**
External Interchange	82	30%	1	10%	26	18%	30	41%	2	14%	2	18%	1	11%
RTC Shutdown Resource	63	23%	0	0%	34	24%	12	16%	4	29%	1	9%	0	0%
Self Scheduled Shutdown/Dispatch	23	8%	0	0%	13	9%	2	3%	2	14%	1	9%	0	0%
Flow Change from Non-Modeled Factors	**18**	**7%**	**7**	**70%**	**48**	**34%**	**14**	**19%**	**4**	**29%**	**6**	**55%**	**5**	**56%**
Loop Flows & Other Non-Market	2	1%	5	50%	11	8%	8	11%	3	21%	3	27%	4	44%
Fixed Schedule PARs	0	0%	2	20%	35	25%	5	7%	1	7%	3	27%	1	11%
Redispatch for Other Constraint (OOM)	16	6%	0	0%	2	1%	1	1%	0	0%	0	0%	0	0%
Other Factors	**85**	**31%**	**2**	**20%**	**20**	**14%**	**15**	**21%**	**2**	**14%**	**1**	**9%**	**3**	**33%**
Load	45	17%	1	10%	10	7%	7	10%	1	7%	0	0%	1	11%
Generator Trip/Derate/Dragging	21	8%	0	0%	9	6%	8	11%	1	7%	1	9%	0	0%
Wind	19	7%	1	10%	1	1%	0	0%	0	0%	0	0%	2	22%
Total	**271**		**10**		**141**		**73**		**14**		**11**		**9**	
Redispatch for Other Constraint (RTD)	**88**		**0**		**15**		**3**		**1**		**6**		**6**	

<u>Key Observations: Transient Real-Time Price Volatility</u>

- Transient shadow price spikes (as defined in this report) occurred in roughly 4 percent of all intervals in 2018.
  - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and re-dispatch for other constraints in RTD.
  - For the West Zone 230kV Lines, the primary drivers were loop flows and other non-market scheduled factors and fluctuations in fixed-schedule PAR flows between NYISO and PJM (i.e., the A, J, K, and 5018 circuits).
  - For the Central-East Interface, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A, J, K, and 5018 lines), generator shutdowns by RTC, and external interchange adjustments.
  - For Dunwoodie-to-Shore Rd 345 kV line, the primary driver was external interchange adjustment. Generator shutdowns by RTC and loop flows and other non-market scheduled factors were two additional key drivers, which were also the primary drivers for other Long Island constraints.
  - For the New York City load pockets, the primary drivers were fluctuations in fixed-schedule PAR flows (i.e., the A line) and loop flows and other non-market factors that affect the constraint transfer capability.

  - For North to Central constraints, the primary drivers were loop flows and other non-market factors that affect the constraint transfer capability and variations in wind output.

- External interchange variations were a key driver of transient price spikes for the power-balance constraint, Dunwoodie-Shore Rd 345 kV line, and the Central-East interface.
  - Large schedule changes caused price spikes in many intervals when generation was ramp-limited in responding to the adjustment in external interchange.
  - CTS with PJM and ISO-NE provide additional opportunities for market participants to schedule transactions such that it will tend to reduce the size of the adjustment around the top-of-the-hour.
    - However, our assessment of the performance of CTS (see Appendix Section IV.C) indicates that inconsistencies between RTC and RTD related to the assumed external transaction ramp profile likely contributes to price volatility when the total net interchange varies significantly (e.g., >200 MW) from one 15-minute interval to another.

- Fixed-schedule PAR-controlled line flow variations were a key driver of price spikes. The operation of the A, J, K, and 5018 lines was a key driver for the West Zone 230kV lines, the Central-East Interface, and the lines in the New York City load pockets.
  - These PARs are modeled as if they fully control pre-contingent flow across the PAR-controlled line, so RTD and RTC assumed the flow across these lines would remain fixed at the most recent telemetered values (plus an adjustment for DNI changes for the PJAC interface). However, this assumption is unrealistic for two reasons:
    - The PARs are not adjusted very frequently in response to variations in generation, load, interchange, and other PAR adjustments. Since each of these PARs is adjusted less than five times per day on average, the telemetered value can change significantly from one interval to the next, resulting in transitory price spikes.
    - When the PARs are adjusted, it may cause congestion that was not anticipated because the operator does not have a model that forecasts the congestion impact of making tap adjustments.

- Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines.
  - Clockwise circulation around Lake Erie puts a large amount of non-market flow on these lines. Circulation can be highly volatile and difficult to predict, since it depends on facilities scheduled outside the NYISO market.

- Generators that are shut down by RTC and/or self-scheduled in a direction that exacerbates a constraint were a significant driver of statewide, Central East, and Long Island price spikes.

  - o A large amount of generation may be scheduled to go offline simultaneously, which may not cause ramp constraints in the 15-minute evaluation by RTC but which may cause ramp constraints in the 5-minute evaluation by RTD. Slow-moving generators such as steam turbines are frequently much more ramp-limited in the 5-minute evaluation than in the 15-minute evaluation.

Discussion of Potential Solutions

- When gas turbines and other units are in the process of shutting-down, they may reduce output quickly. When decommitments are not staggered, it sometimes results in a transitory statewide or local price spike.
  - o RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut-down gas turbines.
  - o Since RTC assumes a 15-minute ramp capability from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage within the 15-minute period.
  - o However, when RTD solves each five-minute market interval, it is unable to delay the shut-down of a gas turbine for five minutes even if it would be economic to do so.
- Large adjustments in external interchange from one 15-minute interval to the next may lead to sudden price spikes.
  - o The "look ahead" evaluations in RTD and RTC evaluate system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange schedules ramp over 10-minute periods from five minutes before the quarter-hour to five minutes after (i.e., from :55 to :05, from :10 to :20, etc.).
  - o Hence, RTC may schedule resources that require a large amount of ramp in one 5-minute portion of the 10-minute external interchange ramp period, and RTD may not anticipate transient shortages that occur in the second five minutes of each 10-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).
- ***Addressing RTC/RTD Inconsistencies*** – 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: [331]
  - o Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

[331] See Recommendation #2012-13

- 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.
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
- Better align the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbines 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.
- Address the inconsistency 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.

- ***Addressing Loop Flows and Other Non-Modeled Factors*** – To reduce unnecessary price volatility from variations in:
  - Loop flows around Lake Erie, we recommend the NYISO make an additional adjustment to the telemetered value. This adjustment should "bias" the loop flow assumption in the clockwise direction to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an under-forecast tends to be much greater than the cost of an over-forecast of the same magnitude).
  - Flows over fixed-schedule PAR-controlled lines, we recommend the NYISO reconsider its method for calculating shift factors. The current method assumes that PAR-controlled line flows are unaffected by generation re-dispatch and load changes, although this is unrealistic.[332]

- Section XI discusses our recommendation for the NYISO to consider including more low-voltage transmission constraints (including 115 kV constraints in upstate New York and 69 kV constraints on Long Island) in the day-ahead and real-time markets.[333] This would also reduce unnecessary price volatility on higher-voltage transmission constraints in the relevant areas because it would allow the NYISO real-time market to re-dispatch generation more efficiently to relieve congestion. Currently, the majority of such re-dispatch occurs through less precise out-of-market instructions.[334]

G. 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,

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332 See Recommendation #2014-9.

333 See Recommendation #2014-12.

334 See Section III.C in the Appendix for more discussion on out-of-merit dispatch for low-voltage transmission system.

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 three types of shortage conditions:

- Shortages of operating reserves and regulation (evaluated in this Subsection);
- Transmission shortages (evaluated in Subsection H); and
- Reliability demand response (evaluated in Subsection I).

Figure A-79: 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-79 summarizes physical ancillary services shortages and their effects on real-time prices in 2017 and 2018 for the following five categories:

- 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 $25/MWh if the shortage is less than 300 MW, $100/MWh if the shortage is between 300 and 655 MW, $200/MWh if the shortage is between 655 and 955 MW, and $750/MWh if the shortage is more than 955 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/MWh.

- 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/MWh.

- 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/MWh.

- 30-minute SENY – The ISO is required to hold 1300 MW of 30-minute operating reserves in Southeast New York and has a demand curve value of $500/MWh.

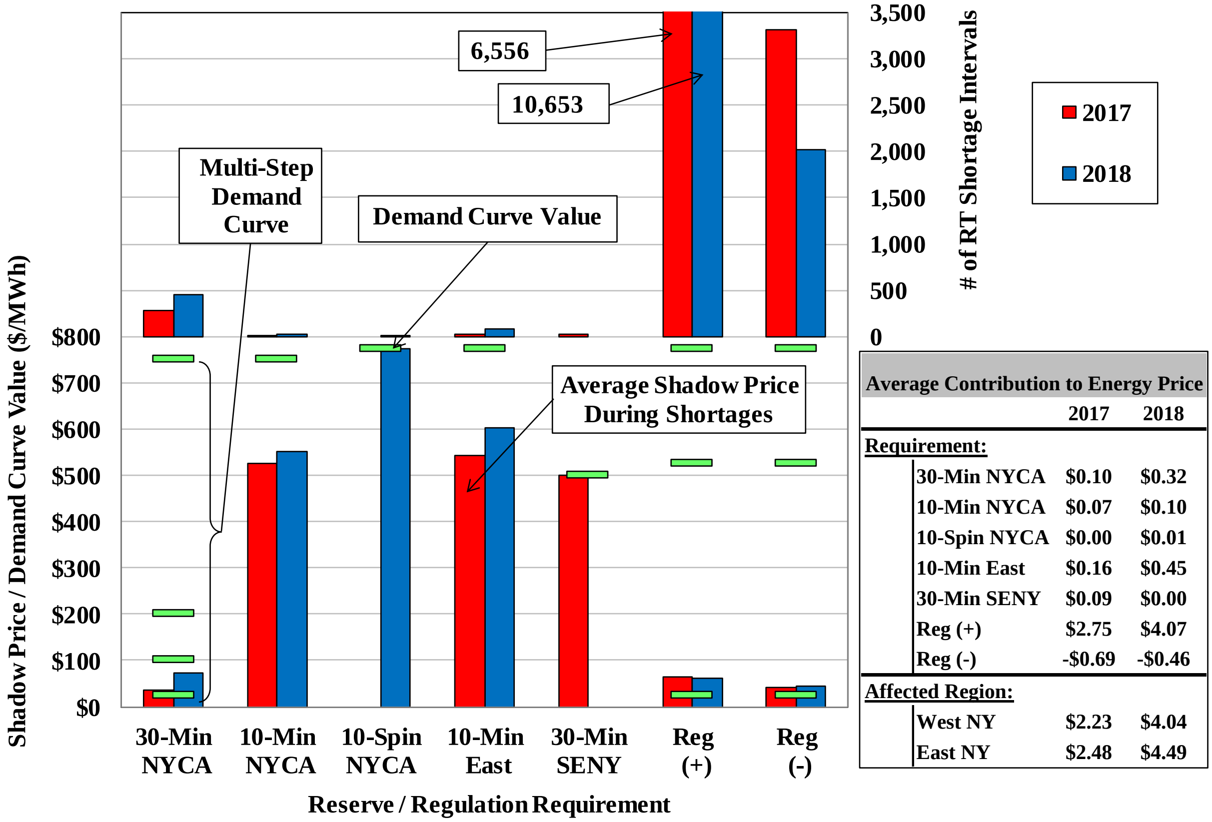
- Regulation – The ISO is required to hold 150 to 300 MW of regulation capability in the state and has a demand curve value of $25/MWh if the shortage is less than 25 MW, $525/MWh if the shortage is between 25 and 80 MW, and $775/MWh if the shortage is more than 80 MW.

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 – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

Figure A-79: Real-Time Prices During Ancillary Services Shortages
2017 – 2018



Average Contribution to Energy Price	2017	2018
Requirement:		
30-Min NYCA	$0.10	$0.32
10-Min NYCA	$0.07	$0.10
10-Spin NYCA	$0.00	$0.01
10-Min East	$0.16	$0.45
30-Min SENY	$0.09	$0.00
Reg (+)	$2.75	$4.07
Reg (-)	-$0.69	-$0.46
Affected Region:		
West NY	$2.23	$4.04
East NY	$2.48	$4.49

Figure A-80 & Figure A-81: Market Operations and Prices During ISO-NE's PFP Event

ISO-NE and PJM implemented their Pay For Performance ("PFP") rules in 2018. PFP rules provide incentives similar to shortage pricing, whereby incremental compensation for energy and reserves can rise to over $4000/MWh during reserve shortages. Consequently, the market incentives that have encouraged generators and power marketers to bring power into New York are changing. Therefore, it is important to evaluate the incentive effects of the PFP rules.

ISO-NE had its first PFP event on September 3, 2018. Figure A-80 and Figure A-81 summarize pricing outcomes and market operations during this event.

Figure A-80 shows the following pricing outcomes in each interval during the event:

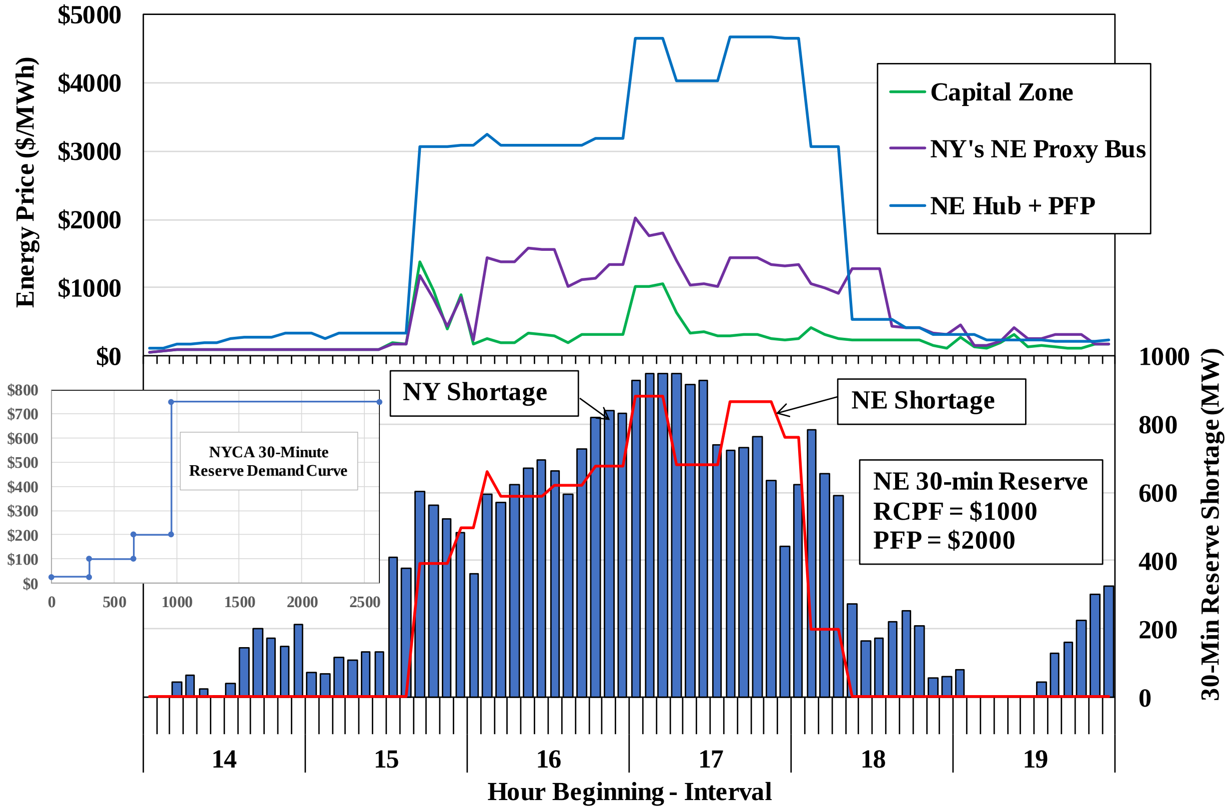
- The shortage quantity of 30-minute reserves in New York;
- The shortage quantity of 30-minute reserves in New England;
- The energy price at the Capital Zone;
- The energy price at the ISO-NE's proxy bus in New York; and
- The energy price at the New England Hub plus a PFP rate of $2000/MWh.

An inset figure also shows the 30-minute reserve demand curve for NYCA.

Figure A-81 shows the following quantities in each interval during the event:

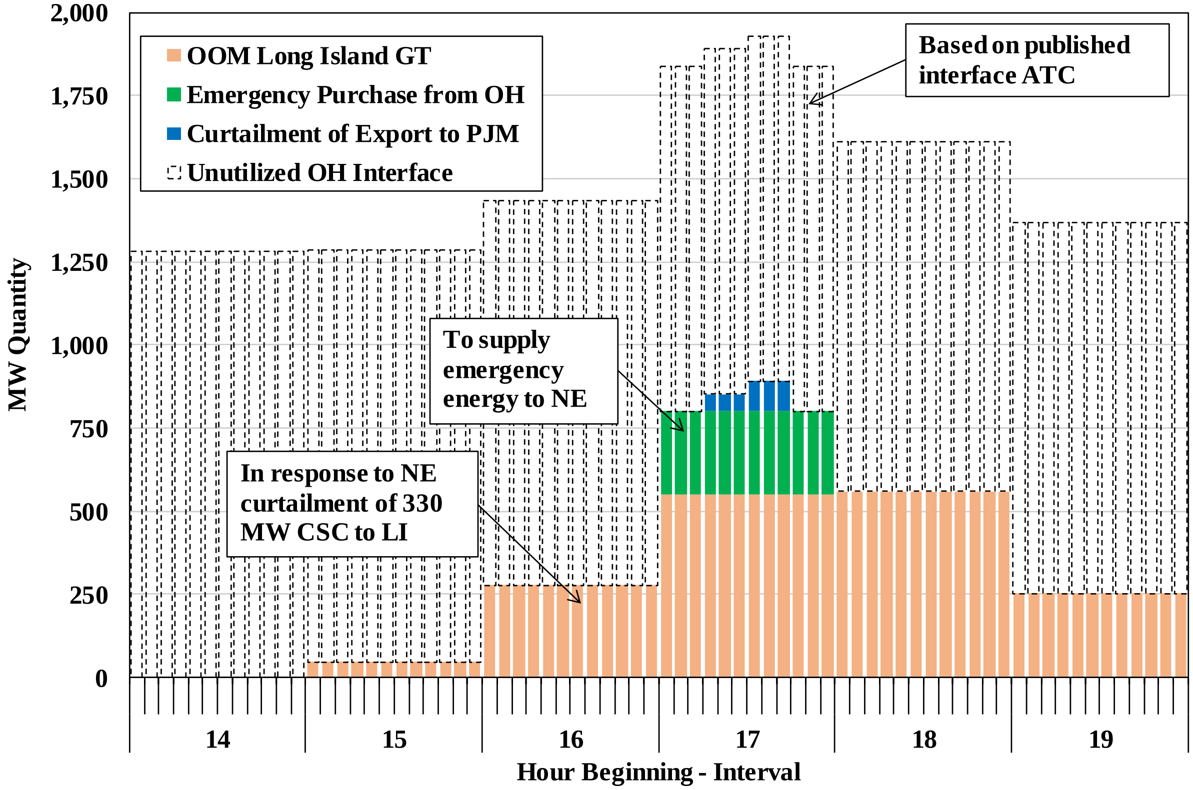
- The amount of peaking resources that are OOMed by the NYISO;
- The amount of emergency energy purchase from Ontario;
- The amount of curtailed exports (by NYISO) to PJM; and
- The unutilized interface transfer capability from Ontario to New York. [335]

Figure A-80: Market Conditions and Prices During ISO-NE's First PFP Event
September 3, 2018



335 This is based on published interface ATC.

Figure A-81: Market Operations During ISO-NE's First PFP Event
September 3, 2018



Key Observations: Market Prices and Operations During Ancillary Services Shortages

- Regulation shortages were most frequent, which occurred in 9 percent of all intervals in 2017 and 12 percent in 2018, and had the largest effects on real-time prices.
  - All other shortages occurred in less than 0.5 percent of all intervals each year.
  - Regulation shortages occurred mostly when the dispatch model "chose" to be short when the cost to provide regulation exceeded its lowest demand curve value of $25/MWh. This happened more frequently in 2018 than in 2017 as a result of higher regulation prices and higher opportunity costs to provide regulation (resulted from higher energy prices).
- The first Pay-for-Performance event occurred on September 3 in ISO-NE, where its system capacity deficiency occurred from 15:40 to 18:15, resulting primarily from under-forecast (~2.5 GW) and forced generation loss (~1.6 GW).
- In this event, ISO-NE engaged in several actions that affected the NYISO market: (see Figure A-81)
  - ISO-NE cut Cross-Sound Cable exports to Long Island (330 MW) from 16:00 to 20:00.
    - NYISO responded via OOM-starting peaking resources on Long Island.

  - ISO-NE made emergency purchases from the NYISO (up to 251 MW from 17:00 to 18:00).
    - The NYISO was also in a 30-minute reserve shortage, so it made emergency purchases from Ontario in order to provide requested emergency energy to NE.
    - The export limit to ISO-NE across the primary interface was temporarily increased from 1400 MW to 1650 MW to facilitate the emergency purchase.
    - The NYISO curtailed several export transactions to PJM (< 100 MW).
- The NYISO and ISO-NE both experienced shortages of 30-minute reserves (see Figure A-80)
  - However, market incentives were substantially different in the two markets.
    - Energy prices on the NYISO side rarely exceeded $200/MWh, while energy prices plus pay-for-performance incentives ranged from $3000/MWh to $4700/MWh on the ISO-NE side.
- ISO-NE had substantially stronger market incentives during shortages because:
  - The demand curve value for the system-wide 30-minute reserves requirement is set at a high value of $1000/MW for any amount of shortage in the ISO-NE market, while it is set at below $200/MW in the NYISO market when the shortage is less than 955 MW. (see Figure A-80)
  - ISO-NE has a pay-for-performance incentive of $2000/MWh (which is scheduled to rise to $5455 in 2022), while the NYISO currently does not have one.
    - PJM has a similar rate to incent performance under tight system conditions.
- The operating reserve demand curves in New York are relatively low considering: (a) the willingness of NYISO operators to engage in OOM actions to procure more costly resources during reserve shortages, and (b) the incentives provided in neighboring markets during shortages.
  - The market incentives to import power into New York under tight conditions were not sufficient.
    - The interface between Ontario and NY had more than 1 GW of available transfer capability during this event.
    - NY had to curtail several export transactions to PJM for system security as well.
  - Therefore, we have recommended that the NYISO consider increasing the operating reserve demand curves to: (a) ensure reliability after PJM and ISO-NE implement PFP rules and (b) do so without resorting to OOM actions.[336]

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[336] See Recommendation #2017-2.

H. Real-Time Prices During Transmission Shortages

Transmission shortages occur when power flows exceed the limit of a transmission constraint. Transmission shortages have widely varying reliability implications. In some cases, they can compel the ISO to shed firm load to maintain system security. However, in many cases, transmission shortages can persist for many hours without damaging transmission 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, [337] and revised this pricing process on June 20, 2017 to improve market efficiency during transmission shortages. Key changes include:

- Modifying the second step of the Graduated Transmission Demand Curve ("GTDC") from $2,350 to $1,175/MWh; and
- Removing the "feasibility screen" and applying the GTDC to all constraints with a non-zero Constraint Reliability Margin ("CRM").[338]

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.

This subsection evaluates market performance during transmission shortages in 2018, focusing on the use of the revised 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.[339] In

337 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.

338 These changes are discussed in detail in Commission Docket ER17-1453-000.

339 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.

such cases, the marginal cost of resources actually dispatched to relieve the constraint is lower than the shadow price set by the offline gas turbine (which is not actually started). The Commission has recognized that it is not efficient for such units to set the clearing price because such a unit: (a) does not reflect the marginal cost of supply that is available to relieve the constraint in that time interval, and (b) does not reflect the marginal value of the constraint that may be violated when it does not generate as assumed in RTD. [340] This category of shortage is evaluated in this section as well.

Figure A-82 & Figure A-83: Real-Time Congestion Management with GTDC

Figure A-82 examines the use of revised GTDC during transmission shortages in the real-time market by constraint group in 2018. 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)[341] showing on the x-axis and the constraint shadow price on the y-axis. The period in 2017 before the revision of GTDC was effective was also plotted for a comparison. The two GTDC curves (old vs. revised) are also plotted to illustrate how constraint shadow costs deviate from the curve in many cases.

340 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.

341 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.

Figure A-82: Real-Time Transmission Shortages with the GTDC

By Transmission Group, 2018

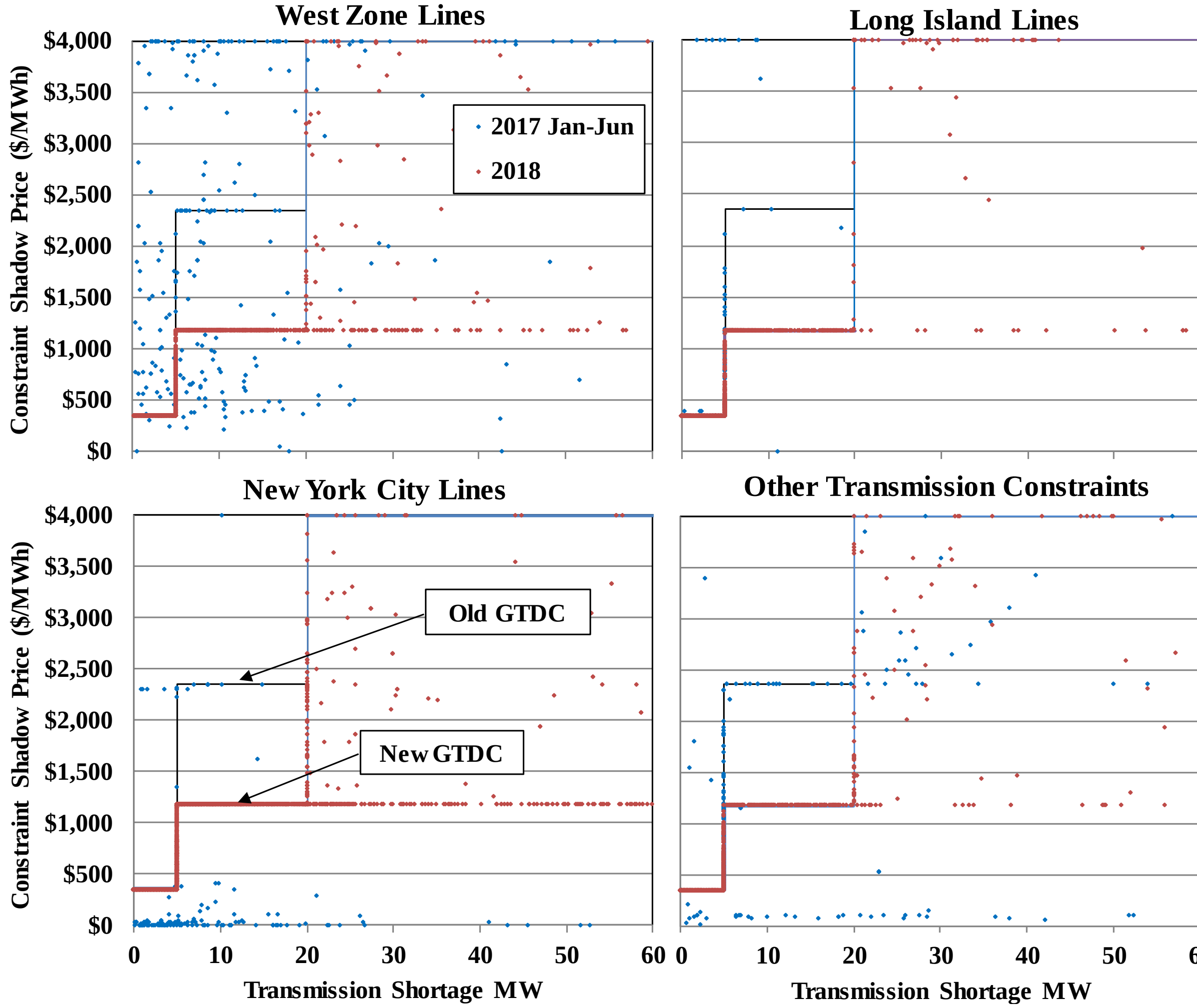


Table A-8 evaluates the effect of CRM on different transmission constraints by summarizing the following quantities for the transmission constraints grouped by facility voltage class and by location during 2018:

- The number of constraint-shortage intervals – indicating the total number of constraint-shortage intervals in each facility group.
- Average constraint limit – indicating the average transmission limit overall all transmission constraints in each facility group.
- Average CRM – indicating the average CRM MW used in each facility group.
- Average shortage quantity - including: 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.
- CRM as a percent of limit – indicating the average CRM as a percentage of average limit.

These quantities are summarized over real-time transmission shortage intervals and for transmission constraints that have a 10+ MW CRM.

Table A-8: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2018

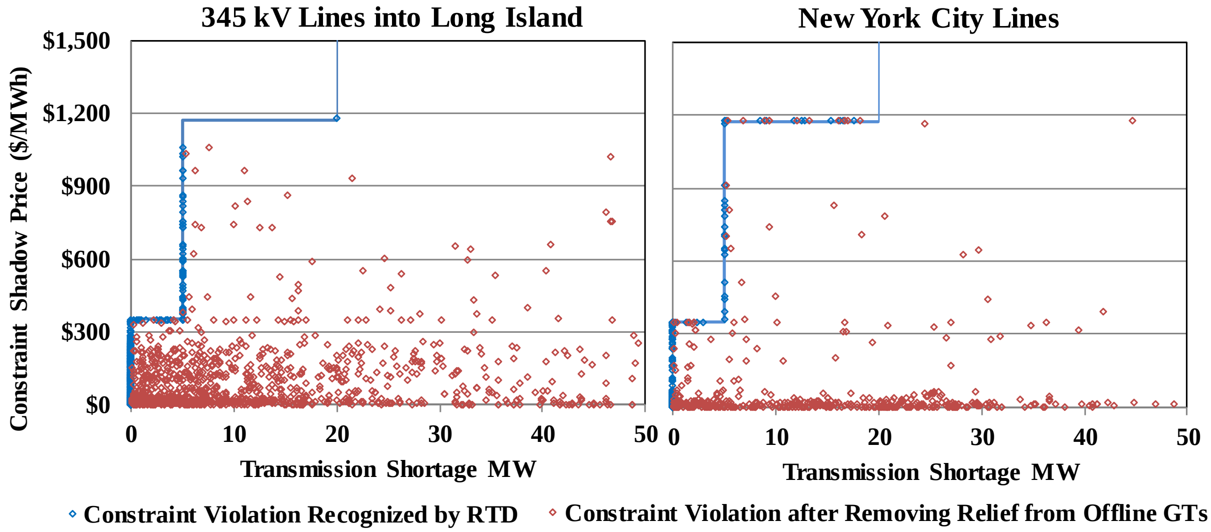
Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals(2)	Avg Constraint Limit (MW)	Avg CRM (MW)	Avg Shortage MW		CRM as % of Limit
					Recognized in Model	Excluding Offline GT	
115 kV	**West(1)**	**311**	**202**	**10**	**4**	**4**	**5%**
	North	1146	141	20	4	4	14%
138 kV	**New York City**	6220	241	20	6	6	8%
	Long Island	2025	281	28	4	8	10%
230 kV	**West**	1275	681	45	9	9	7%
	North	80	403	20	7	7	5%
	All Others	17	503	20	5	5	4%
345 kV	**New York City**	1174	823	20	7	14	2%
	North	206	1602	50	38	42	3%
	Long Island	1364	797	50	1	15	6%
	All Others	147	1737	28	12	28	2%

Note: (1) This includes 115 kV constraints modeled in the market software effective on December 4, 2018
(2) A transmission shortage is measured excluding the congestion-relief effects from offline GTs.

Figure A-83 examines the pricing effects of offline GTs on transmission shortages in 2018 for select transmission groups: a) the two 345 kV transmission circuits from upstate to Long Island; and b) 138 and 345 kV transmission constraints into and within New York City. Offline GTs were used frequently to alleviate transmission shortages on these transmission facilities during the examined period.

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-83: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2018



Key Observations: Real-Time Prices During Transmission Shortages

- Constraint relaxation has been much less frequent following the revision of transmission shortage pricing in June 2017.
  - Only 7 percent of all transmission shortages involved constraint relaxation in 2018, compared with over 50 percent in the periods before the revision.
- Less frequent use of constraint relaxation greatly improved pricing efficiency during transmission outages, which resulted in:
  - That constraint shadow prices were more correlated with the severity of the shortage (e.g., the shortage amount, the duration of the constraint), and
  - That congestion was more transparent and predictable for market participants.
  - Therefore, it is desirable to minimize the use of constraint relaxation.
- Despite overall improved market outcomes, at times constraint shadow prices still did not properly reflect the importance and severity of a transmission shortage.
  - A default CRM value of 20 MW is used for most facilities regardless of their actual physical limits. On average, this was roughly: (see Table A-8)
    - 2 percent of the transfer capability of the 345 kV constrained facilities;
    - 4 percent of the transfer capability of the 230 kV constrained facilities;
    - 9 percent of the transfer capability of the 138 kV constrained facilities; and
    - 14 percent of the transfer capability of the 115 kV constrained facilities.

- However, loop flows and other un-modeled factors do not rise in this pattern at low voltages.

- The 20 MW CRM is overly conservative for lower-voltage constraints, which leads to unnecessarily high congestion costs in these areas.
  - The average size of shortages on the 115 kV constraints was less than 5 MW. And over-constraining these small facilities has large effects on inter-regional flows.
  - For example, a 10-MW reduction in flows across a Browns Falls-Taylorville 115 kV line can reduce overall transfers from Northern New York to Central New York by 100 MW.
- The NYISO recognized this issue and implemented revisions to its tariff to permit the use of non-zero CRM values less than 20 MW in December 2018. We support this change.
  - A 10 MW CRM is currently used for modeled 115 kV transmission constraints in upstate New York..
- Higher CRMs are used for a small set of facilities to account for more uncertain loop flows and other un-modeled factors.
  - For example, a 50 MW CRM is used for the Dunwoodie-Shore Rd 345 kV line, which accounted for a significant portion of congestion on Long Island.
  - However, actual flows were frequently well below their operational limits (because of the high CRM) during periods of modeled congestion. The average shortage quantity was only 15 MW on the Dunwoodie-Shore Rd constraint, leading the GTDC to often over-value constraint violations. (see Table A-8)

- Therefore, we continue to recommend in the long-term replace current transmission shortage pricing process with a set of constraint-specific GTDCs because they ensure a clear relationship between the shadow price and the severity of the constraint that is a better signal to market participants. [342]

- The shadow prices that result from offline GT pricing are not well-correlated with the severity of the transmission constraint, leading to prices during tight operating conditions that are volatile.
  - The introduction of constraint-specific GTDCs should enable the NYISO to phase-out the use of offline fast-start pricing.

342 Recommendation #2015-17 discusses how the NYISO should further enhance real-time scheduling models during periods of severe congestion.

I. Real-Time Prices During Reliability Demand Response Deployments

The NYISO provides demand resources with two programs that compensate them for providing additional flexibility to the energy market. These programs include the Emergency Demand Response Program (EDRP) and the ICAP/SCR program. Resources enrolled in these programs typically earn the higher of $500/MWh or the real-time LBMP when called upon. Given the high costs associated with the programs, it would only be efficient to call upon these resources when all of the cheaper generation has been dispatched. However, the use of demand resources is complicated by scheduling lead times and other inflexibilities. First, the NYISO must determine how much demand response to activate when there is still considerable uncertainty about the needs of the system. Second, the demand response may not be needed for the entire activation period. Hence, there may be substantial surplus capacity during portions of the event. Therefore, it is important to set real-time prices that properly reflect the costs of maintaining reliability when reliability demand response resources are deployed.

Figure A-84 to Figure A-86 DR Deployments and Scarcity Pricing

NYISO deployed demand response (EDRPs and SCRs) on three days (July 2, August 28 and 29) in 2018. All of these activations were in Zone J for New York City operating reserve needs. The subsection evaluates during these event: a) whether real-time prices efficiently reflected system conditions; and b) whether demand response deployments were necessary in retrospect to maintain adequate capacity.

In particular, Figure A-84 to Figure A-86 summarize scarcity pricing outcomes during the three EDRP/SCR deployments by showing the following quantities in each interval of the events:

- Available capacity (shown as stacked areas in the figures) – Includes three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
  - Already scheduled 30-minute reserves;
  - Unscheduled 30-Minute reserves; and
  - Additional available capacity (beyond 30-min rampable).
  - Each of the three categories is shown for SRE and non-SRE resources separately.
- The amount of EDRP/SCR deployed by the NYISO plus 30-minute reserves requirement (solid black line in the bottom portion of the figure).
- The amount of EDRP/SCR deployed by the NYISO plus 30-minute reserves requirement plus the additional amount of demand response deployed by local utility (dashed black line in the bottom portion of the figure).
- Constraint shadow prices on the 30-minute reserve requirement in each region (blue line in the top portion of the figure).

Figure A-86 also shows two additional quantities for New York City (which currently has no reserves requirement):

- Actual needs for 30-minute reserves (solid red line); and
- Actual needs for 30-minute reserves plus EDRP/SCR deployed by the NYISO plus additional demand response deployed by local utility (dashed red line).

The deployment of demand resources was likely necessary to avoid a capacity deficiency when the amount of demand response deployment plus normal 30-minute reserve needs in that region exceeds available capacity. This is shown for New York City in Figure A-84 when the red line is higher than all areas combined.

Figure A-84: Demand Response Deployments and Scarcity Pricing
NYCA, 2018

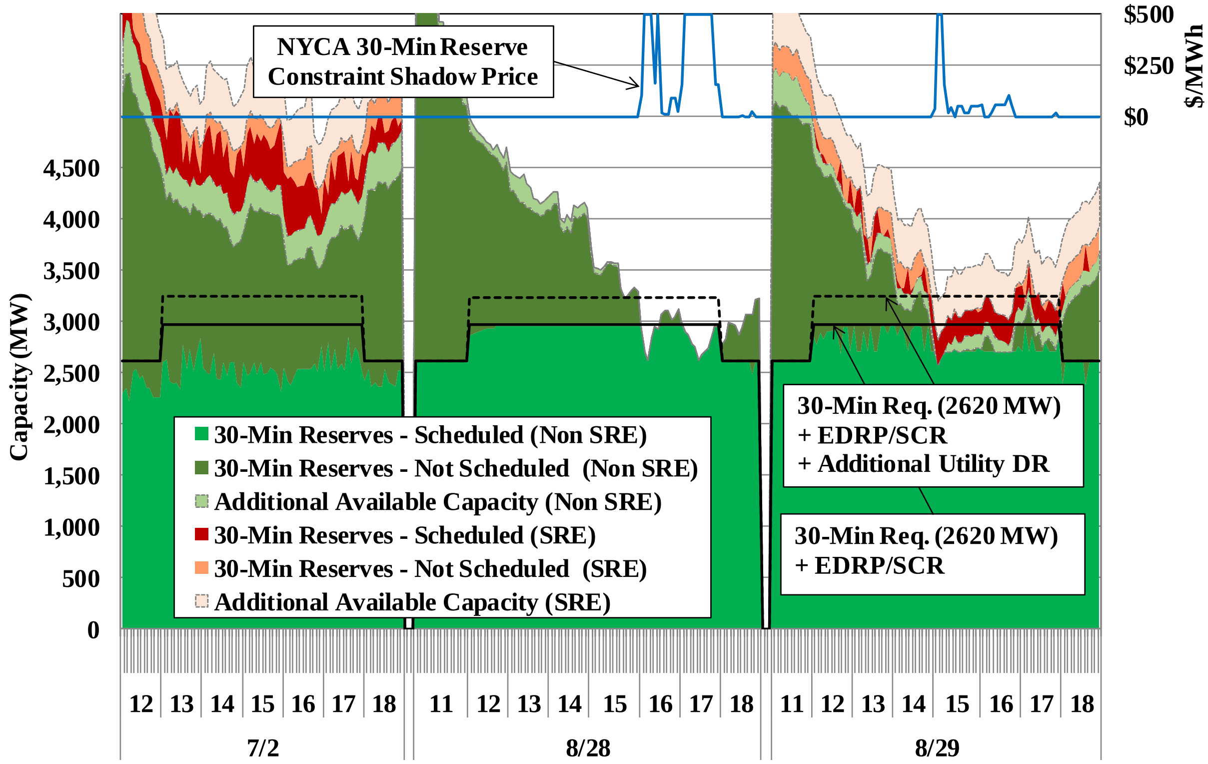


Figure A-85: Demand Response Deployments and Scarcity Pricing
Southeast New York, 2018

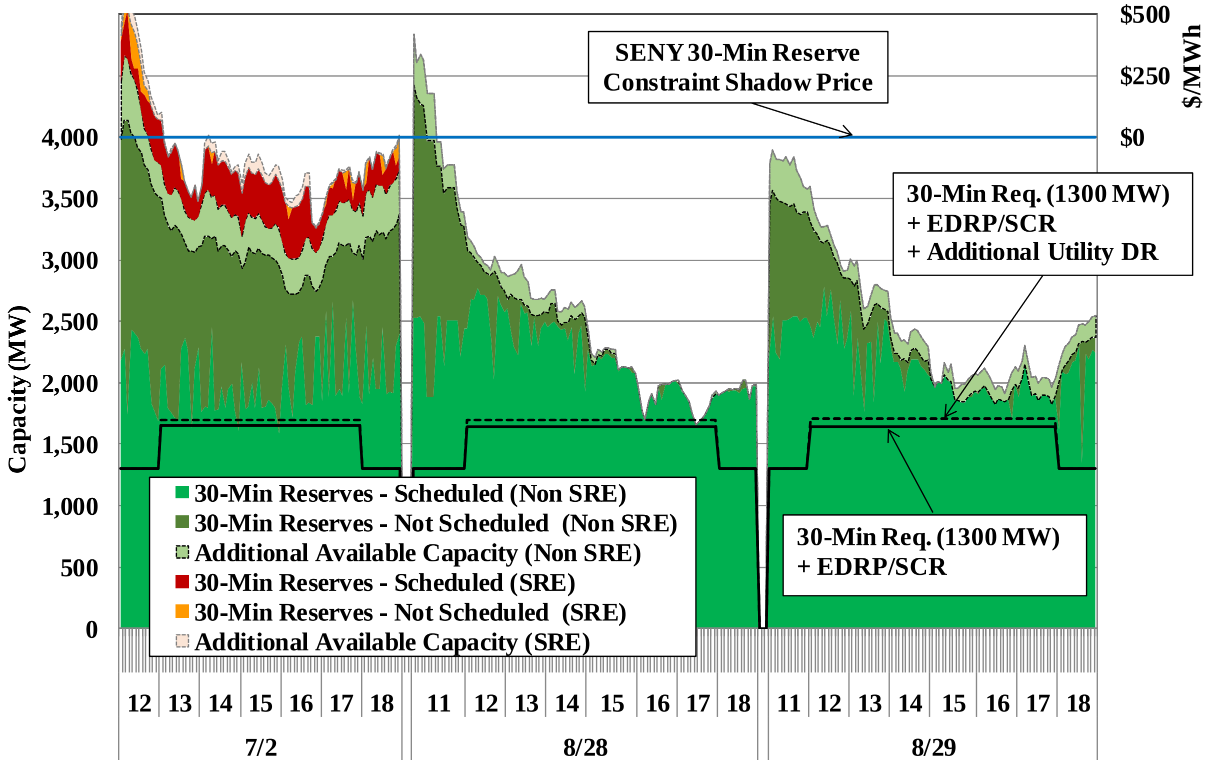
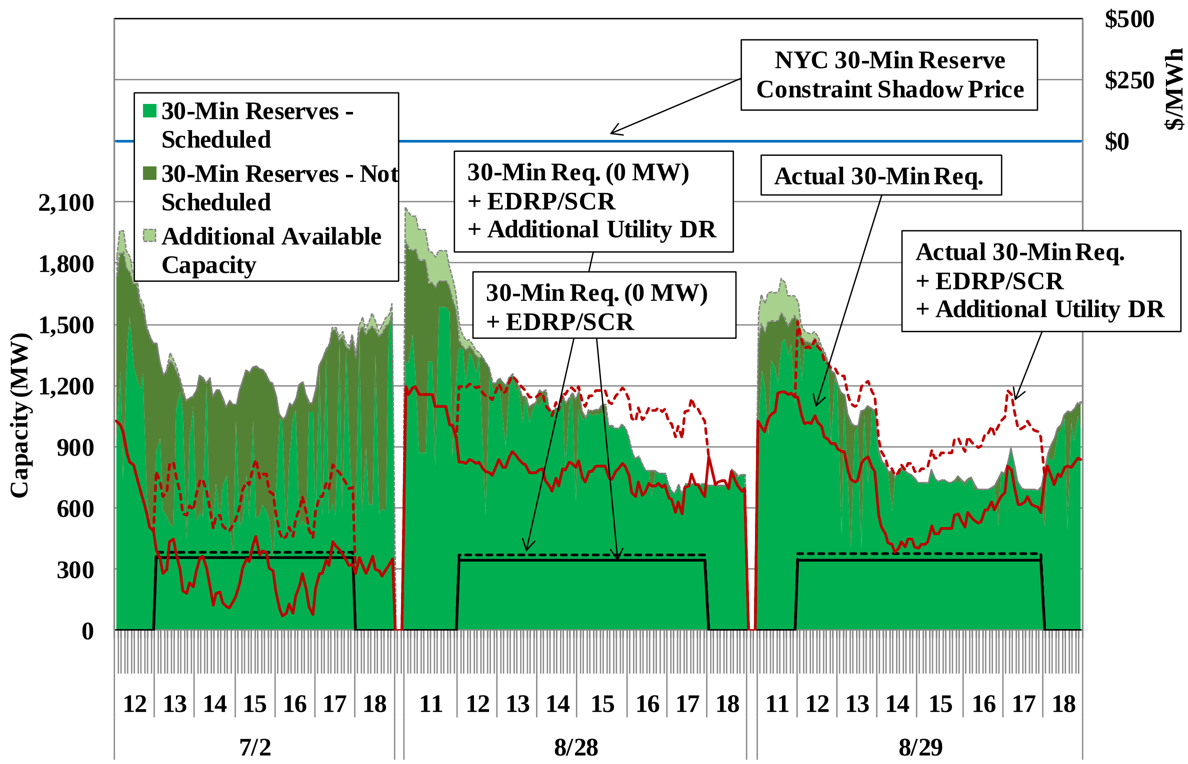


Figure A-86: Demand Response Deployments and Scarcity Pricing
New York City, 2018



Key Observations: Real-Time Prices During Transmission Shortages

- The NYISO activated EDRP/SCR in Zone J on three days in 2018 (i.e., July 2, August 28 and 29), all for NYC operating reserve needs.
  - Peak load ranged from roughly 31.3 GW on July 2 to 31.9 GW on August 29.
  - NYISO activated 480-495 MW of EDRP/SCR each day, while most utilities activated their own demand response programs, adding additional 375-390 MW on each of the three days as well.
  - In addition, NYISO SREed three units (Danskammer 4, Bowline 1, and Oswego 5) for July 2 and one unit (Oswego 6) for August 29 for forecasted capacity needs. [343]
- Our evaluation suggests that, in retrospect:
  - Both SREs and DR were needed to prevent brief NYCA capacity deficiencies on August 28 and 29, but they were not needed on July 2.[344]
    - On July 2, actual load was far below forecast (by ~2 GW) due to pop-up showers, and 30-minute reserves were priced at $0/MWh during the DR activation.
- Utility DR MW is not considered in the current scarcity pricing rules.
  - Additional Utility DR deployments helped avoid a NYCA capacity deficiency for an additional 11 intervals on August 28. However, 30-minute reserves were priced only at an average of $88/MWh during these intervals. (see Figure A-84)
  - Various amounts of Utility DR were activated on nine other days when the NYISO did not call EDRP/SCR, but prices did not reflect the cost of these actions.
  - It would be beneficial for the NYISO to work with TOs to evaluate the feasibility of including Utility DR deployments in the scarcity pricing rules.
- NYISO deployments prevented NYC capacity deficiencies on August 28 and 29. (see Figure A-86)
  - This is shown in the figure when the dashed red line is higher than all areas.
  - Estimated actual reserve needs (based on the N-1-1 thermal requirement for New York City) averaged nearly 650 MW during DR deployments (see the solid red line).
  - However, this reserve need is not explicitly modeled in the market software.

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343 See presentation “NYISO Summer 2018 Hot Weather Operations” by Wes Yeomans at 9/26 MC meeting for more details.

344 SREs and/or DR are necessary to avoid a capacity deficiency when: *DR deployed + normal 30-min reserve need > all available capacity (without SRE).*

- Out-of-market actions (DARU, LRR, SRE, OOM, and DR calls) are often needed to satisfy the reserve requirement, which led to over $30 million of BPCG uplift in New York City in 2018. (see Figure A-91))

- We have recommended the NYISO model local reserve requirements in New York City load pockets.[345] An effort is currently underway for the NYISO to implement 10-minute and 30-minute reserve requirements for the New York City Zone in mid-2019.[346] However, sub-zone reserve requirements are not being addressed in this implementation.

J. Supplemental Commitment and Out of Merit Dispatch

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. Similarly, the NYISO and local Transmission Owners sometimes dispatch generators out-of-merit order ("OOM") in order to:

- Manage constraints of high voltage transmission facilities that are not fully represented in the market model; or

- Maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is frequently uneconomic, which displaces economic production. Both types of out-of-market action lead 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 and OOM dispatches to be as limited as possible.

In this section, we evaluate several aspects of market operations that are related to the ISO's process to ensure that sufficient resources are available to meet the forecasted load and reliability requirements. In this sub-section, we examine: (a) supplemental commitment for reliability and focus particularly on New York City where most reliability commitments occur; and (b) the patterns of OOM dispatch in several areas of New York. In the next sub-section, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

Figure A-87: 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:

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345 See Recommendation #2017-1.

346 See "Establishing Zone J Operating Reserves" by Ashley Ferrer at MC meeting on March 27, 2019

- 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.

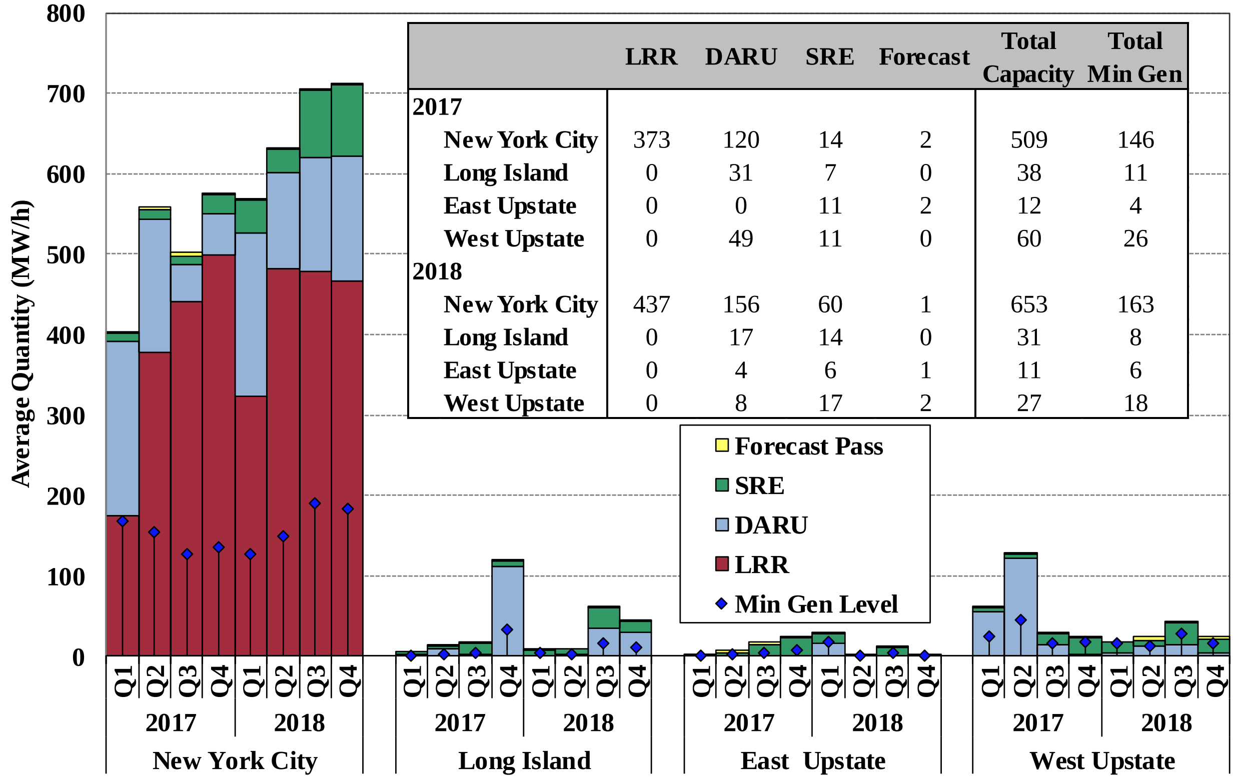
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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, in order to commit units efficiently, SCUC must have accurate assumptions regarding the needs in each local reliability area.

Figure A-87 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 2017 and 2018. 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 2017 and 2018 on an annual basis.

Figure A-87: Supplemental Commitment for Reliability in New York
By Category and Region, 2017 – 2018



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2017						
New York City	373	120	14	2	509	146
Long Island	0	31	7	0	38	11
East Upstate	0	0	11	2	12	4
West Upstate	0	49	11	0	60	26
2018						
New York City	437	156	60	1	653	163
Long Island	0	17	14	0	31	8
East Upstate	0	4	6	1	11	6
West Upstate	0	8	17	2	27	18

Figure A-88 & Figure A-89: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability typically occurred in New York City. Figure A-88 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-88 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2017 and 2018.

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: [347]

- Voltage – If needed for Application of Reliability Rule ("ARR") 26 and no other reason. This occurs when additional resources are needed to maintain voltage without shedding load in an N-1-1 scenario.

- Thermal – If needed for ARR 37 and no other reason. This occurs when additional resources are needed to maintain flows below acceptable levels without shedding load in an N-1-1 scenario.

347 A unit is considered to be committed for a LRR constraint if the constraint 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. [348]
- NOx Only – If needed for NOx bubble and no other reason. [349] 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 scenario.
- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, NOx, or Loss of Gas. The capacity is shown multiple times for each separate reason in the bar chart.

In Figure A-88, for voltage and thermal constraints, the capacity is shown for the load pocket that was secured, including:

- AELP - Astoria East Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket
- ERLP - East River Load Pocket
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

The pie chart in the figure shows the portion of total capacity committed under different reasons for 2018 only.

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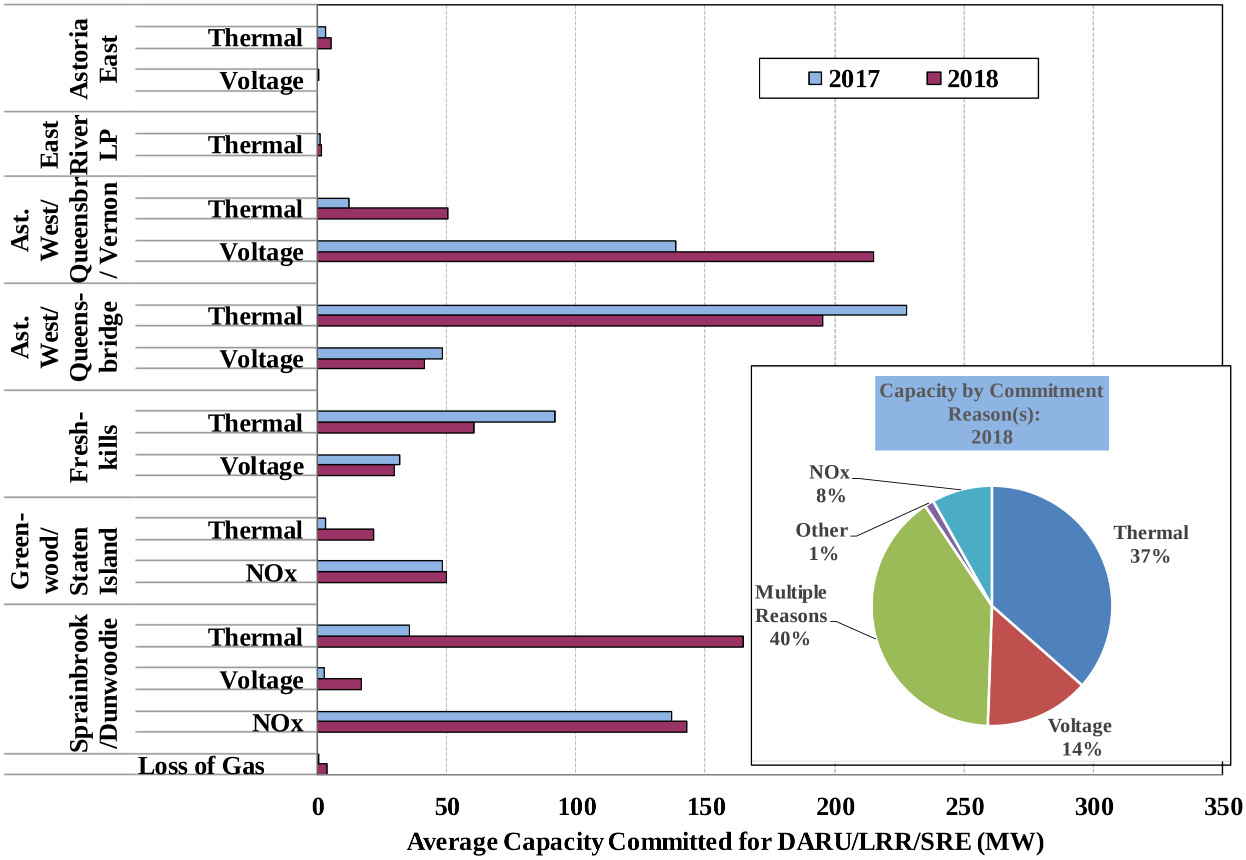
348 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

349 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 at: http://www.dec.ny.gov/regs/4217.html#13915.

Figure A-88: Supplemental Commitment for Reliability in New York City
By Category and Region, 2017 – 2018



The previous figure shows that reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1 criteria) in New York City. Since such units would not be economic if they were not needed for local reliability, they ordinarily do not earn enough market revenue to recoup their day-ahead as-offered costs. Hence, such units typically receive a day-ahead BPCG payments.

Although the resulting amount of compensation (i.e., revenue = cost) is reasonably efficient for the marginal commitment needed to satisfy the needs of the pocket, it does not provide efficient incentives for lower-cost resources that can also provide valuable operating reserves in the pocket to be available. Moreover, it does not provide investors with efficient incentives to invest in new and existing resources that are capable of satisfying the need at a lower cost. Therefore, it would be beneficial for the NYISO to seek ways to design a reserve product that could satisfy the local N-1-1 requirements in a way that provides market-based compensation to all suppliers that provide the service in the load pocket, not just the ones with high operating costs.

To assess the potential market incentives that would result from modeling local N-1-1 requirements in New York City, we estimated the average clearing prices that would have occurred in 2018 if the NYISO were to devise a day-ahead market requirement that set clearing prices using the following rules:

- If a single unit was committed for a single load pocket requirement: Price in \$/MW-day = $DA\_BPCG_g \div UOL_g$.
- If a single unit was committed for NOx to make gas turbines available for a single load pocket requirement: Price in \$/MW-day = $DA\_BPCG_g \div UOL_{GT}$.
- If a single unit was committed for more than one load pocket requirement: the Price for each load pocket in \$/MW-day = $DA\_BPCG_g \div UOL_g \div$ # of load pockets.
- If two units are committed for a single load pocket, the price is based on the generator g with a larger value of $DA\_BPCG_g \div UOL_g$.
- If two units are committed for different non-overlapping load pockets, the price is calculated for each load pocket in the same manner as a single unit for a single load pocket.
- If two units are committed for two load pockets where one circumscribes the other, the price of the interior pocket is calculated in the same manner as a single unit for a single load pocket, and the price of the outer pocket is calculated as $Price_{outer} = \max\{\$0,(DA\_BPCG_{g\_outer} \div UOL_{g\_outer}) - Price_{interior})$.

Table A-9 summarizes the results of this evaluation based on 2018 market results for four locations in New York City: the 345kV network north of Staten Island, the Astoria West/Queensbridge load pocket, the Vernon location on the 138 kV network, and the Greenwood/Staten Island load pocket. Several other load pockets would also have binding N-1-1 requirements, but we were unable to finalize the estimates for those pockets. Ultimately, this analysis is meant to be illustrative of the potential benefits of satisfying these requirements through the day-ahead and real-time markets.

Table A-9: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets
2018

Area	Average Marginal Commitment Cost (\$/MWh)
NYC 345 kV System	**\$2.01**
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	**\$5.18**
Vernon	**\$4.23**
Greenwood/Staten Is.	**\$3.39**

Key Observations: Reliability Commitment

- Reliability commitment averaged roughly 720 MW in 2018, up 17 percent from 2017.

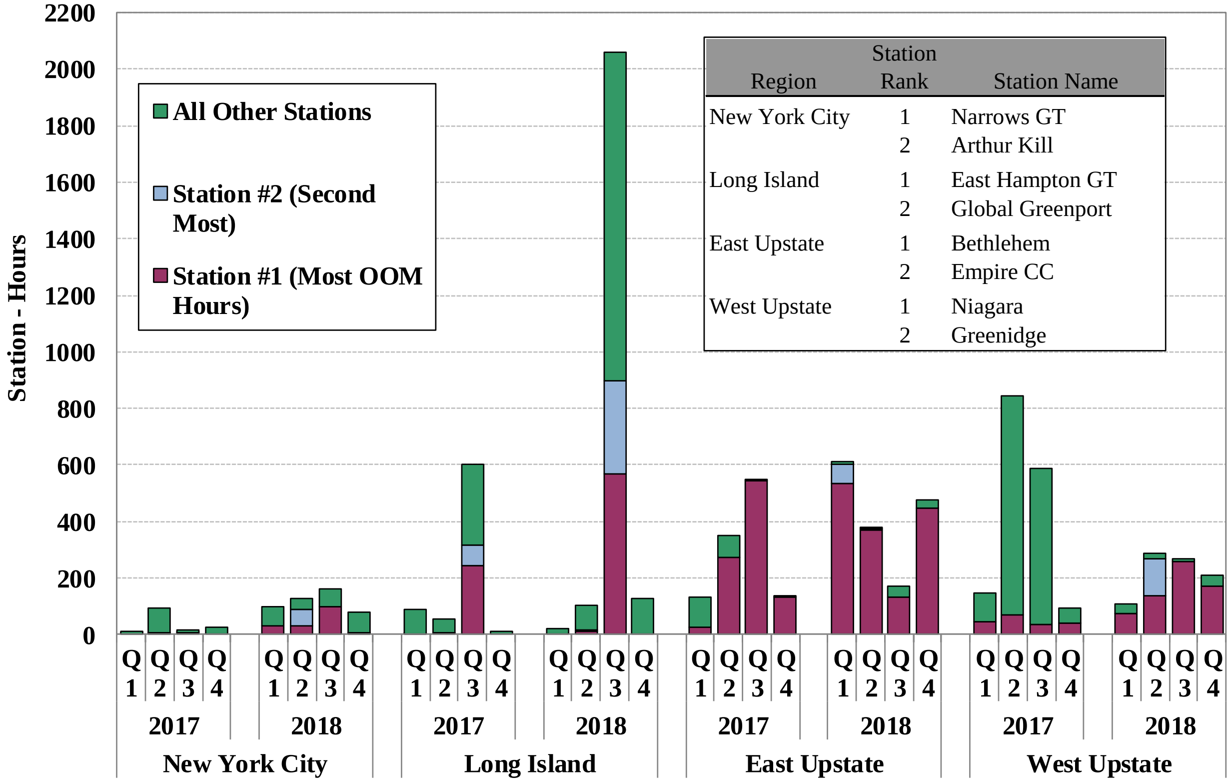
- The increase occurred primarily in New York City, which rose 28 percent from a year ago and accounted for 90 percent of total reliability commitment in 2018.
  - Higher load levels and lengthy transmission outages greatly increased the need to commit generation for the N-1-1 thermal requirement in the 345 kV system.
  - In addition, the local needs in the Astoria West/Queensbridge/Vernon load pocket increased partly because of more planned generation outages of combined-cycle units in the pocket.
  - Based on our analysis of operating reserve price levels that would be necessary to represent the marginal costs of satisfying N-1-1 requirements in the day-ahead market, we find such price levels would range from an average of $2.01/MWh in most areas to as much as $5.18/MWh in the Astoria West/Queensbridge load pocket.
- Reliability comments in other areas were relatively infrequent in 2018.
  - DARU commitment in Western New York fell notably since July 2017 following the completion of transmission upgrades that allowed for the expiration of Milliken RSSA.

Figure A-89: Frequency of Out-of-Merit Dispatch

Figure A-89 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2017 and 2018 for the following 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.

In each region, the two stations with the highest number of OOM dispatch hours during 2018 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2018, and "Station #2" is the station with the second-highest number of OOM hours). The figure also excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.

Figure A-89: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2017 - 2018



Key Observations: OOM Dispatch [350]

- Generators were dispatched Out-of-Merit ("OOM") for roughly 5,290 station-hours in 2018, up 42 percent from 2017.
  - OOM levels increased more than 200 percent on Long Island, which occurred primarily in the summer months.
    - High-cost peaking resources were frequently OOMed to manage congestion on the 69 kV network and voltage needs on the East End of Long Island during high load conditions.
  - Higher load levels also led the Bethlehem units to be OOMed more frequently to manage post-contingency flow on the Albany-Greenbush 115 kV facility.
  - However, OOM levels in Western New York fell nearly 50 percent from 2017, due partly to transmission upgrades completed in July 2017, which allowed the Milliken RSSA to expire and reduced OOM needs.

350 A detailed evaluation of the actions used to manage low-voltage network congestion in New York is provided in Appendix Section III.C.

- Not shown in the figure, the Niagara facility was still often manually instructed to shift output between the generators at the 115kV station and the generators at the 230kV station in order to secure certain 115kV and/or 230kV transmission facilities.[351]
  - In 2018, this manual shift was required in more than 1,000 hours to manage 115 kV, 230 kV, or 345 kV constraints.
  - The NYISO implemented an enhanced modeling of the Niagara Plant in December 2018, which better recognizes the congestion impact from turbines at individual buses.[352] This should help greatly reduce the manual shift and improve the efficiency of scheduling and pricing.

K. Uplift Costs from Guarantee Payments

Uplift charges from guarantee payments accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. Figure A-90 and Figure A-91 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 the local Transmission Owner.

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.

351 These were not classified as OOM in hours when the NYISO did not adjust the UOL or LOL of the Resource.

352 See "Niagara Generation Modeling Update" by David Edelson at MIWG meeting on May 9, 2018.

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.

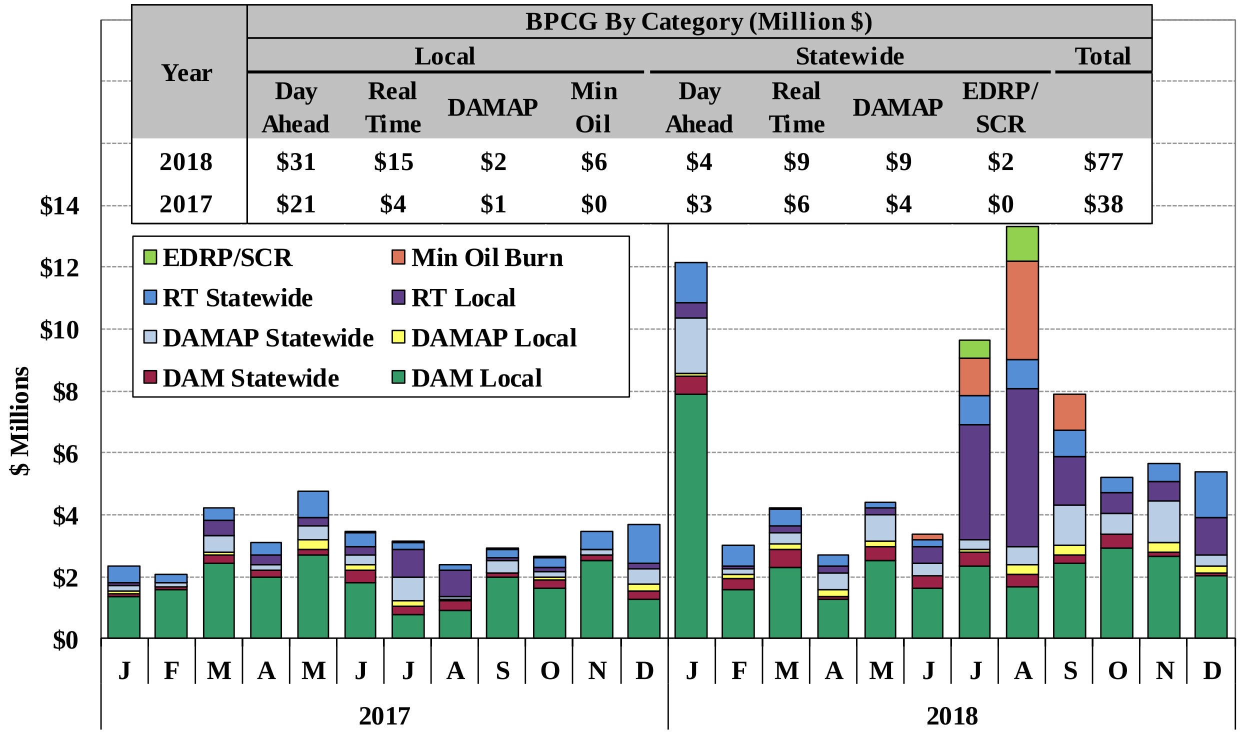
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-90 & Figure A-91: Uplift Costs from Guarantee Payments

Figure A-90 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2017 and 2018. 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-91 shows the seven categories of uplift charges on a quarterly basis in 2017 and 2018 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.

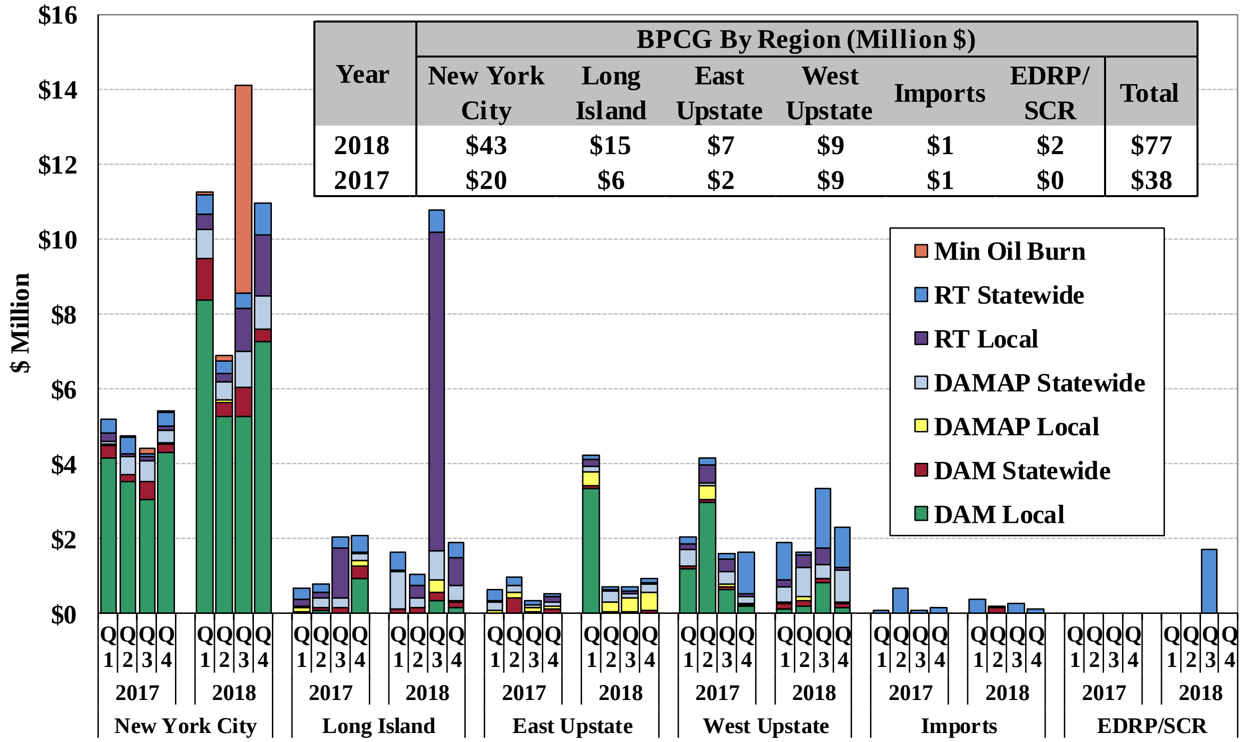
It is also noted that Figure A-90 and Figure A-91 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-90: Uplift Costs from Guarantee Payments by Month
2017 – 2018



Year	Local: Day Ahead	Local: Real Time	Local: DAMAP	Local: Min Oil	Statewide: Day Ahead	Statewide: Real Time	Statewide: DAMAP	Statewide: EDRP/ SCR	Total
2018	$31	$15	$2	$6	$4	$9	$9	$2	$77
2017	$21	$4	$1	$0	$3	$6	$4	$0	$38

Figure A-91: Uplift Costs from Guarantee Payments by Region
2017 – 2018



Year	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2018	$43	$15	$7	$9	$1	$2	$77
2017	$20	$6	$2	$9	$1	$0	$38

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift rose 102 percent from $38 million in 2017 to $77 million in 2018. This was driven by:
  - Increased supplemental commitments and OOM levels (for the reasons discussed earlier); and
  - Higher natural gas prices, which increased the commitment costs of gas-fired units.
- New York City accounted for $45 million of BPCG in 2018, of which:
  - Nearly $6 million accrued from the Min Oil Burn requirements;
    - One or more steam units burned a blend of oil and gas in 220 hours.
  - Over $26 million were paid to generators committed for N-1-1 local requirements.
    - We have recommended the NYISO model local reserve requirements to satisfy these N-1-1 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals. [353]
- Nearly $10 million of BPCG uplift accrued on high-cost peaking resources on Long Island when OOMed to manage 69 kV congestion and local voltage needs.
  - We have recommended the NYISO consider modeling certain 69 kV constraints and local voltage requirements on Long Island in the day-ahead and real-time markets. [354]

353 See Recommendation #2017-1.

354 See Recommendation #2014-12.

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.[355] 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.[356]

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

355 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 18.2 percent in the most recent Capability Year (i.e., the period from May 2018 to April 2019). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

356 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 103.5 percent from May 2017 to April 2018 and again 103.5 percent from May 2018 to April 2019. The New York City LCR was 81.5 percent from May 2017 to April 2018 and 80.5 percent from May 2018 to April 2019. The LCR for the G-J Locality was set at 91.5 percent from May 2017 to April 2018 and 94.5 percent from May 2017 to April 2018. Each IRM Report recommends Minimum LCRs for New York City, Long Island, and the G-J Locality, which the NYISO considers before issuing recommended LCRs in its annual Locational Minimum Installed Capacity Requirements Study, which may be found at "https://www.nyiso.com/documents/20142/3056465/LCR2018_Report.pdf/249964c0-9ea9-c6ee-c265-435d0290aff7".

purchased in each locality in each monthly UCAP spot auction.[357] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction purchases more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

The demand curve for a capacity market Locality is defined as a straight line through the following two points: [358]

- 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".

- 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.[359] 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);

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357 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.

358 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2017/2018 and 2018/2019 Capability Years may be found in NYISO MST 5.14.1.2. The demand curves are defined as a function of the UCAP requirements in each locality, which may be found at "https://www.nyiso.com/documents/20142/1399473/Demand-Curve-UCAP-translation-Summer-2018.pdf/37e5aeca-d825-fa4a-be34-d30fe8f503c7".

359 Before the 2016 demand curve reset, the demand curves were reset every three years rather than four. Materials related to past Demand Curve Reset studies may be found at: "https://www.nyiso.com/installed-capacity-market".

- Capacity supply and quantities purchased each month as well as clearing prices in monthly spot auctions (sub-section D and E);
- Cost of improving reliability from additional capacity by zone (sub-section F); and
- The need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section G).

A. Installed Capacity of Generators in NYCA

Figure A-92 - Figure A-93: Installed Summer Capacity and Forecasted Peak Demand

The bottom panel of Figure A-92 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 2009 through 2019.[360] The top panel of Figure A-92 shows the amount of capacity that entered or exited the market during each year.[361] Figure A-93 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).

360 The summer 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 available at: https://www.nyiso.com/documents/20142/2226333/2018-Load-Capacity-Data-Report-Gold-Book.pdf/7014d670-2896-e729-0992-be44eb935cc2.

361 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-92: Installed Summer Capacity of Generation by Prime Mover
2009 - 2019

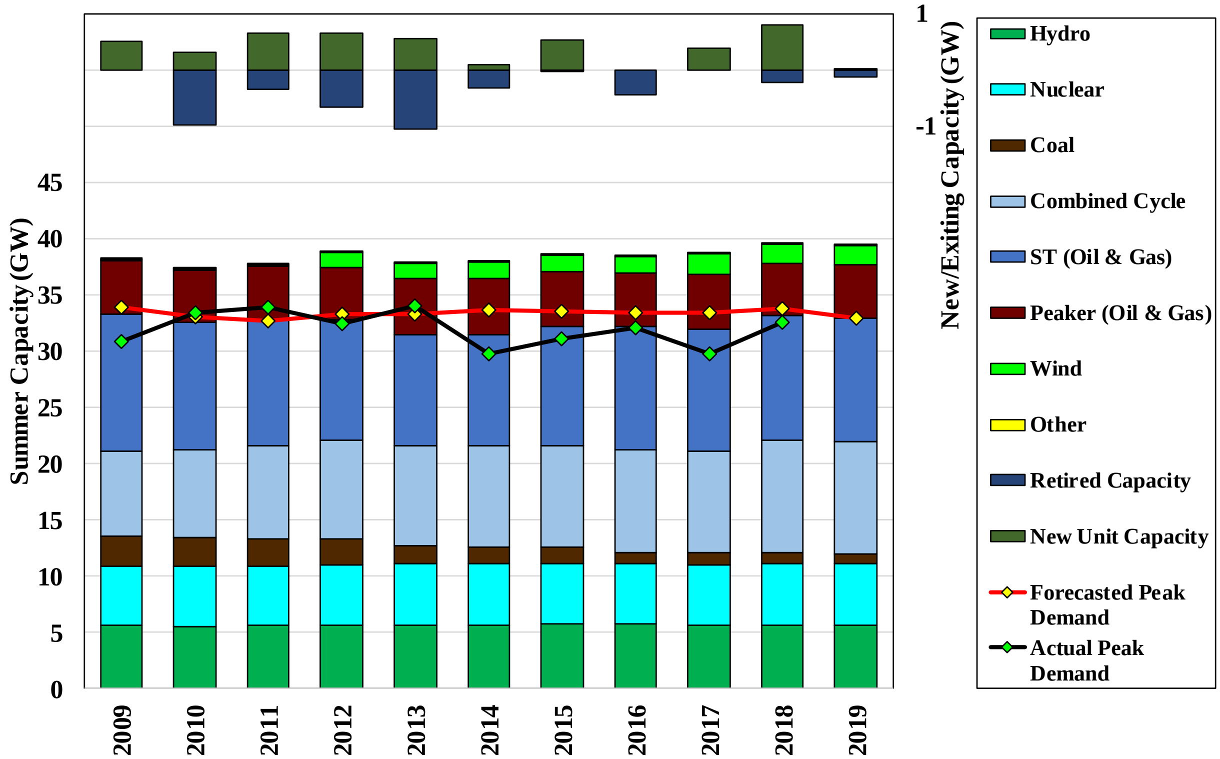
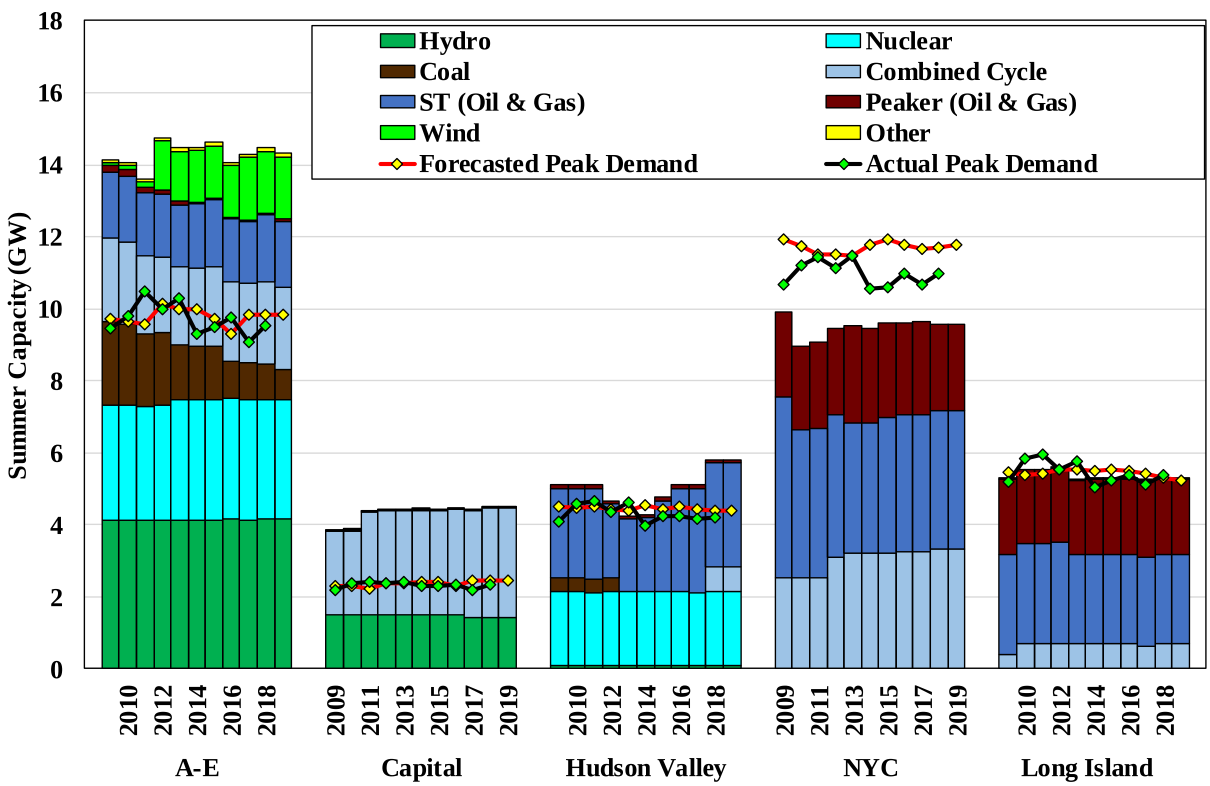


Figure A-93: Installed Summer Capacity of Generation by Region and by Prime Mover
2009 – 2019



Key Observations: Installed Capacity in NYISO

- The total generating capacity in the NYISO remained relatively flat just under 40 GW (summer) between 2009 and 2019. However, since 2009, more than 4 GW of capacity has left the market either through retirement, mothball, or ICAP-Ineligible Forced Outage. In the same timeframe, roughly 4.5 GW of capacity has entered the market as new resources or units returning from a mothball status. The 2018 capacity mix in New York is predominantly gas and oil resources (65 percent) while the remainder is primarily hydro and nuclear (each 14 percent).
    - While the total natural gas-fired capacity has increased minorly since 2009, roughly 2.5 GW of new combined cycle resources have entered the market. Major gas-fired unit additions include the Empire (Capital zone), Caithness (Long Island), Astoria Energy II (New York City), Bayonne I and II (New York City), and CPV Valley (Hudson Valley) facilities that commenced commercial operations between 2009 and 2018.
    - Policies promoting renewable energy have motivated investment in new wind units, adding nearly 2 GW of nameplate capacity to the state resource mix. Most of this capacity is located in zones A-E, with significant amounts of additional wind and solar PV capacity projected to enter as the procurement of Tier1 Renewable Energy Credits accelerates under the Clean Energy Standard. [362]
    - On the other hand, a combination of low gas prices and stronger environmental regulations have led to the retirement of the majority of coal-fired generating facilities in New York. The capacity associated with coal units has shrunk from nearly 3 GW in 2009 to less than 1 GW heading into 2019, a 64 percent decrease.[363] The forthcoming environmental regulations may require large additional expenditures for GTs in the downstate areas, and could result in retirement of several units. Other notable retirements include several dual-fueled steam units such as Poletti 1 in NYC in 2010. Astoria 4 in NYC in 2012, and the Glenwood 04 and 05 units in Long Island in 2012.
- As shown in Figure A-93, a dichotomy exists in the state between the eastern and western regions with the western zones (Zones A-E) possessing greater fuel diversity in the mix of installed capacity resources. This stands in contrast to the eastern zones (Zones F-K) which tend to rely more exclusively on gas and oil-fired resources.
    - Gas and oil-fired generators comprise just under 30 percent of the installed capacity in zones A-E, whereas almost 100 percent of installed capacity in Zones J and K are gas or oil-fired units. The planned retirement of the Indian Point nuclear units will

362 See Section VII.C of the Appendix for the contribution of federal and state incentives to the net revenues of a hypothetical wind unit in New York.

363 The reduction in coal capacity in the state and the corresponding drop in total installed capacity is not directly one-to-one since four units at the Danskammer station converted from coal to natural gas-fired.

exacerbate the downstate fuel diversity situation with almost the entirety of remaining installed capacity in zones G-K being gas or oil-fired.[364]

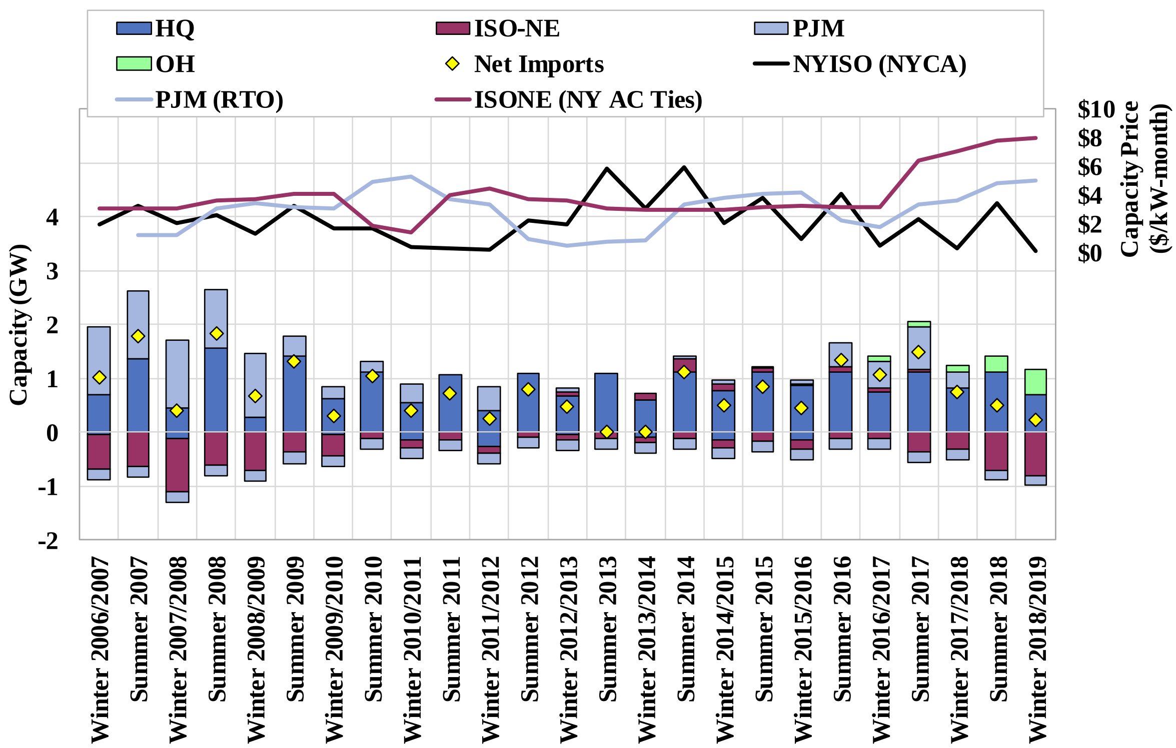
- While the fuel diversity in the state exists primarily in the western zones, there has been considerably larger new investments in non-wind resources in the eastern zones where capacity prices tend to be higher.

B. Capacity Imports and Exports

Figure A-94: NYISO Capacity Imports and Exports by Interface

Figure A-94 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2006/07 through Winter 2018/19 along with capacity prices in the New York Control Area and its neighboring control areas.[365] The capacity imported from each region is shown by the positive value stacked bars, while the capacity exported from NYCA is shown as negative value bars. The capacity prices shown in the figure are: (a) the NYCA spot auction price for NYISO; (b) the RTO price in the Base Residual Auction for PJM; and (c) the NY AC Ties price in the Forward Capacity Auction for ISO-NE.

Figure A-94: NYISO Capacity Imports and Exports by Interface
Winter 2006/07– Winter 2018/19



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364 Entergy announced on Jan 9, 2017 its intent to close the Indian Point nuclear units in 2020 and 2021. See: "www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/".

365 The data shown is the monthly average of capacity imported/ exported over the capability period.

Key Observations: Capacity Imports and Exports

- Capacity imports and exports flow between NYISO and four of its neighboring regions: Hydro Quebec ("HQ"), Ontario ("OH"), PJM, and ISO-NE. NYISO's net capacity imports have fluctuated over the years, and are a function of several factors that include price differences between control areas and seasonality.

- HQ is a large exporter of hydro capacity with an internal load profile that peaks in the winter. Since the Summer 2010 capability period, the imports from HQ have been close to their maximum CRIS-allocated value, averaging nearly 1.2 GW in Summer Capability Periods. However, imports from HQ during winter months dip substantially.

- Imports from PJM have historically constituted the second largest source of external capacity into the NYISO.
  - Imports from PJM were substantial prior to the Summer 2009 Capability Period, and exceeded 1 GW during several capability periods. However, the level of imports from PJM has remained fairly low since the NYISO Open Access Transmission Tariff ("OATT") was amended to place more stringent deliverability criteria on external capacity sources.[366]
  - Imports from PJM increased considerably during the 2016/17 and the 2017/18 Capability Years, and averaged roughly 440 MW and 780 MW in the summer capability periods for 2016 and 2017, respectively. Much of that change was likely driven by regional price differences and the low cost of selling capacity into NYCA.
  - In 2018, the NYISO implemented changes to its Tariff requiring external resources seeking to sell capacity in NYISO along the PJM AC-Interface to acquire firm transmission rights. Consequently, capacity imports from PJM fell to an average of just 11 MW in the 2018/19 Capability Year (through January 2019).[367, 368]

- The trend in capacity exports to ISO-NE reversed from recent years, with a substantial amount of capacity (600 MW to 800 MW) sold over the NY-NE AC Ties.

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366 NYISO filed tariff revisions to the OATT that redefined the requirements for external generators to acquire and maintain CRIS rights pursuant to Section 25 of Attachment S of the OATT. These filings followed the FERC's decision supporting the measures in 126 FERC 61,046 (January 15, 2009). For more information, refer to: https://www.ferc.gov/whats-new/comm-meet/2009/011509/E-7.pdf.

367 The changes to requirements of external capacity suppliers are outlined in §4.9.3 of the NYISO ICAP Manual. See https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

368 Capacity price differences between the NYISO and PJM are not the only driver of capacity imports. There are major structural differences between the two regions' procurement mechanisms (for instance, PJM's three-year forward procurement relative to New York's monthly spot procurement) which limit the extent to which imports respond to price differentials.

- Recent retirements in New England and structural changes to the Forward Capacity Auctions (e.g. sloped demand curves) have yielded much higher capacity prices since Summer 2017. Consequently, larger amounts of New York capacity were exported to ISO-NE during the 2018/ 2019 Capability Year.

- The NYISO signed an MOU with IESO in 2016 regarding import of capacity from Ontario beginning with the Winter 2016/2017 Capability Period. Since then, capacity imports from Ontario have increased with the increase in ICAP import rights.[369]

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 (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.[370] This gives suppliers a strong 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 six most recent 12-month rolling average EFORd values of resources in the Locality in accordance with Sections 2.5 and 2.7 of the NYISO's Installed Capacity Manual.[371]

Table A-10: Historic Derating Factors by Locality

Table A-10 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2014 onwards.

Table A-10: Derating Factors by Locality
Summer 2014 – Winter 2018/19

Locality	Summer 2018	Summer 2017	Summer 2016	Summer 2015	Summer 2014	Winter 2018/19	Winter 2017/18	Winter 2016/17	Winter 2015/16	Winter 2014/15
G-I	4.92%	12.70%	5.00%	3.40%	6.86%	6.45%	11.72%	6.46%	4.24%	5.72%
LI	6.28%	5.60%	7.27%	7.83%	7.65%	6.90%	6.07%	6.36%	9.02%	8.28%
NYC	7.09%	4.37%	9.53%	6.92%	5.44%	5.98%	5.26%	5.44%	10.49%	5.06%
A-F	10.01%	10.48%	10.62%	10.21%	10.92%	8.46%	8.96%	8.12%	9.43%	8.50%
NYCA	8.56%	9.29%	9.61%	8.54%	9.08%	7.57%	8.43%	7.25%	9.06%	7.32%

369 The NYISO Installed Capacity Manual outlines the steps required for capacity outside of the state to qualify as an External Installed Capacity Supplier in sections 4.9.1.

370 The variables and methodology used to calculate EFORd for a resource can be found at http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F%20-%20Equations.pdf

371 The Derating Factor used in each six-month capability period for each Locality may be found at: "https://www.nyiso.com/installed-capacity-market."

Key Observations: Equivalent Forced Outage Rates

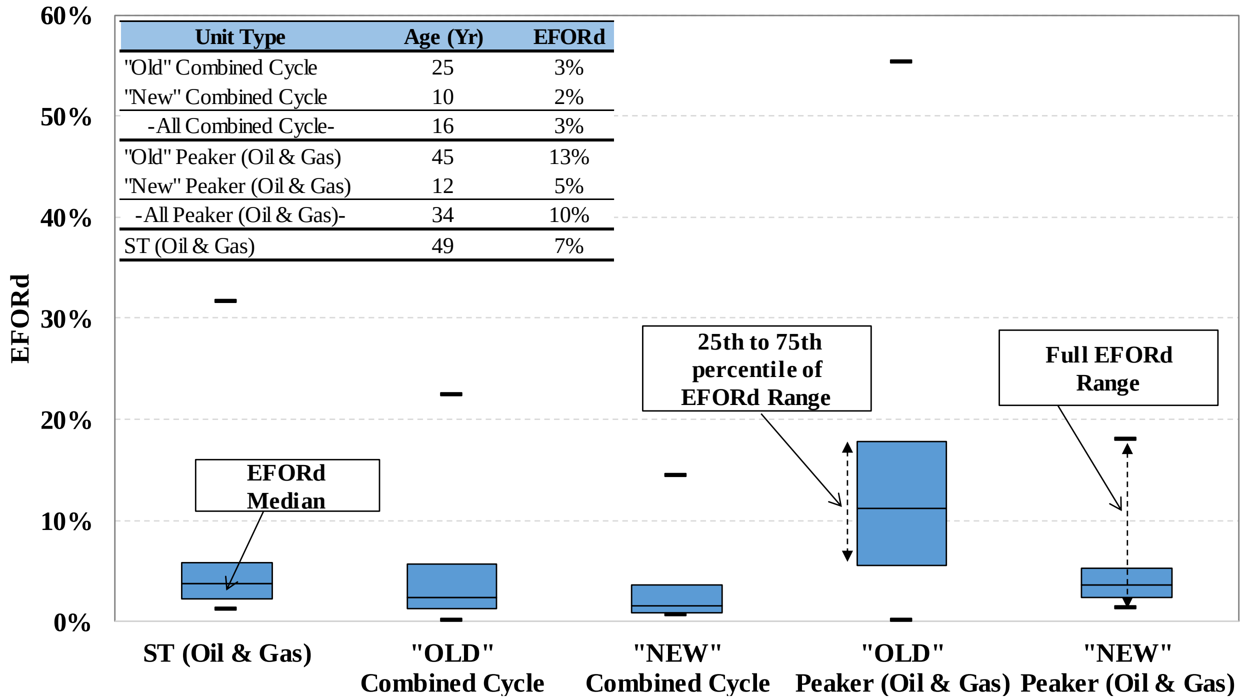
- The NYCA-wide Derating Factor decreased (i.e., improved) from Summer 2017 to Summer 2018 (by 0.73 percentage points) and from Winter 2017/18 to the Winter 2018/19 Capability Period (by 0.86 percentage points).
  - The change in NYCA-wide summer and winter Derating Factors can largely be attributed to the decreases in the EFORd of generation located in the Hudson Valley, although this improvement was offset to a large extent by increased EFORd at a few large generators in NYC.
- The Derating Factor for Zones A-F is generally higher than observed in other zones.
  - As shown in Figure A-93, nearly 10 percent of the installed generating facilities located in Zones A-F are intermittent in nature. Consequently, the average EFORd of capacity resources located in Zones A-F is higher than the average EFORd for other zones, where the resources are predominantly gas, oil-fired, or nuclear units.
- The NYC Derating Factor is prone to considerable swings from one year to the next based on the performance of its old generation fleet. Although over 2 GW of relatively new gas-fired capacity is interconnected in this zone, it also contains several old peaking units which run for very few hours and can be prone to outages and large changes in EFORd.

Figure A-95: Gas and Oil-Fired EFORds by Technology Type and Region

Figure A-95 presents the distribution of EFORds of natural gas and oil-fired units based on technology type and age designation. [372] The column bars for each technology-age indicate the EFORd spread of the middle two quartiles (i.e. 25 to 75 percentile). The line inside each bar denotes the median value of EFORd for the specified capacity type. Each column is bounded by two dashed lines that denote the full range of observed EFORd values for the given technology. The table included in the chart gives the capacity-weighted average age and EFORd of each technology-age category.

[372] The age classification is based on the age of the plant. Units that are older than 20 year are tagged as "OLD" while younger units are marked as "NEW."

Figure A-95: EFORd of Gas and Oil-fired Generation by Age
Summer – Five-Year Average



Key Observations: EFORd of Gas and Oil Units

- As shown in Figure A-95, the distribution of EFORds varies considerably by technology-type and unit age. Units that are new and units that have a greater number of annual operating hours tend to have lower EFORds.

- Combined cycle units are the youngest gas and oil-fired generators in New York and have lower average EFORd values than steam turbine and peaking units. Newer combined cycle units also display the least variation in EFORd values of all technology-age categories.

- Steam units have the second lowest average EFORd despite being the oldest units on average in the state.
  - The methodology for calculating EFORd relies on a number of factors, including the number of hours during which the plant generates power. In situations where two units have similar operating profiles insofar as the outage frequency per start, outage duration, and the number of starts, the EFORd calculation favors the unit that runs for more hours per start. Consequently, steam units have lower EFORds than peaking units.

- The EFORd values for peaking units tend to be highest on average and also exhibit a greater degree of variance when compared to other types of units.

- The age of peaking units in New York ranges from less than one year to over 50 years. The reliability (and EFORd) of a unit is likely to be affected by the age of the facility.
- Peaking units tend to have higher operating costs than other units and are likely to be committed for fewer hours a year. So, the number of sample hours over which the relevant observations (for calculating the EFORd) are made is small. This contributes to the high variance in estimated EFORds across peaking units. Therefore, for units that are equally likely to experience a forced outage, the EFORd calculation methodology is likely to result in a greater variance in EFORds for units with high operating costs, when compared to the variance in EFORds for a group of more efficient units.

D. Capacity Market Results: NYCA

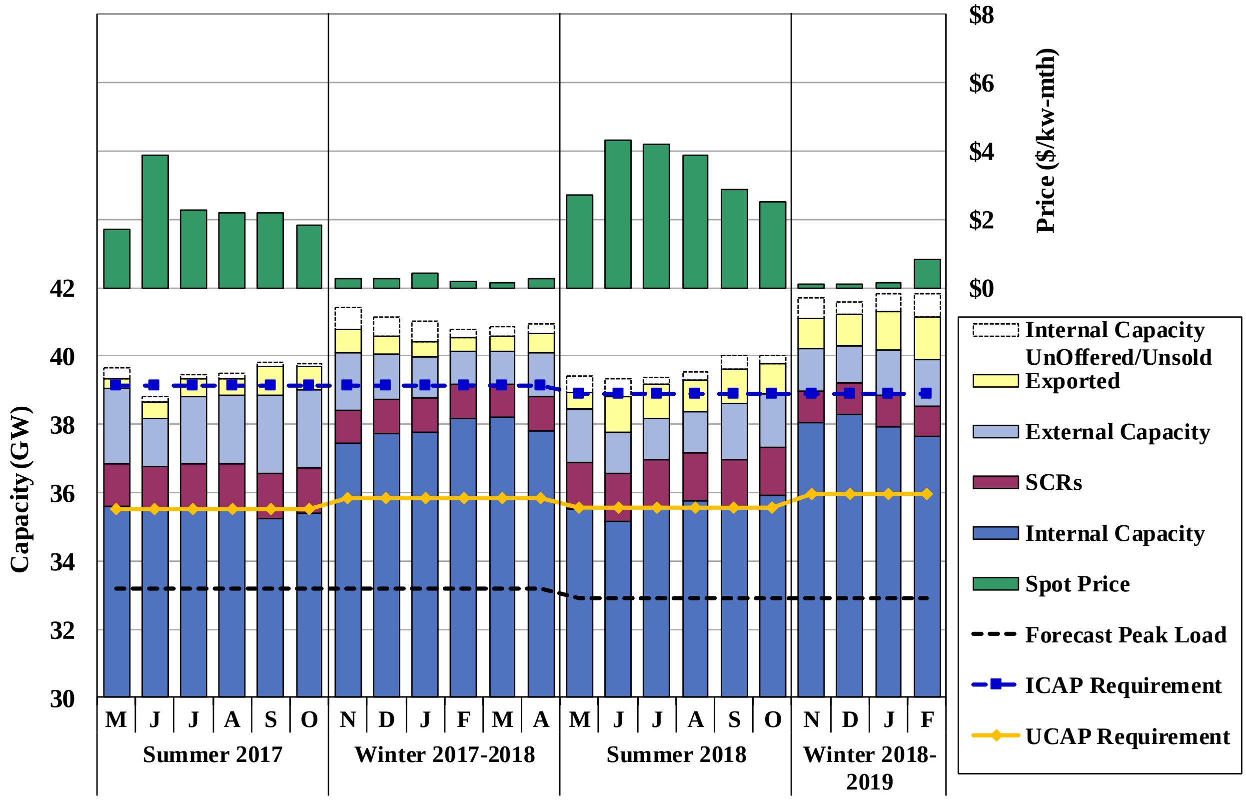
Figure A-96: Capacity Sales and Prices in NYCA

Figure A-96 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.[373] 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, Figure A-96 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 Figure A-96 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, Figure A-96 also shows the forecasted peak load and the ICAP requirements.

373 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-96: UCAP Sales and Prices in NYCA
May 2017 to February 2019



Key Observations: UCAP Sales and Prices in New York

- Seasonal variations drive significant changes in clearing prices in spot auctions between Winter and Summer Capability Periods.
  - Additional capability is typically available in the Winter Capability Periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity. This contributes to significantly lower prices in the winter than in the summer.
  - Capacity imports from Quebec typically fall in the coldest winter months (i.e., December through March), since Quebec is a winter peaking region. This reduction partially offsets the decreases in clearing prices during these months.
- UCAP spot prices rose overall in Rest of State in the 2018/19 Capability Year, relative to the previous year.
  - The spot price averaged $3.42/kW-month in the Summer 2017 Capability Period, which was up 46 percent from the prior summer, and $0.29/kW-month in the Winter 2016/17 Capability Period, which was up 3 percent from the prior winter.

- Summer prices rose primarily due to much lower net import levels from external control areas, particularly from the elimination of PJM imports and increases in exports to ISO-NE.
- New capacity additions like the CPV Valley combined cycle station and Bayonne CTG9 and CTG10 helped to increase internal generation, though some units (Ravenswood GTs and Milliken 2) exited the market by means of IIFO outages.
- Although summer prices were higher in 2018, the winter period prices remained relatively constant at exceedingly low values on account of a large surplus of installed capacity in the NYISO markets (the UCAP margin in the winter has averaged above 111 percent, which is near the Zero-Crossing Point of the NYCA Demand Curve).
- The 2018/19 ICAP requirement fell 259 MW from the 2017/18 Capability Year because of a decrease in the peak load forecast.[374]
  - However, the UCAP Requirement rose 49 MW in the Summer Capability Period and 97 MW in the Winter Capability Period because of the year-over-year increase in Derating Factors.
  - In the short-term, spot capacity prices are affected most by the ICAP Requirement in each locality (as opposed to the UCAP Requirement), since variations in the Derating Factor closely track variations in the weighted-average EFORd values of resources.
  - However, in the long-term, higher Derating Factors tend to increase the IRM and the LCRs because the IRM Report incorporates EFORd values on a five-year rolling average basis.

E. Capacity Market Results: Local Capacity Zones

Figure A-97 - Figure A-99: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-97 to Figure A-99 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-96 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

374 ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2018 Summer and 2018/19 Winter Capability Periods. UCAP Requirements are fixed for a six-month Capability Period, since the Derating Factor for each locality is updated every six months, causing differences in the UCAP requirements during the summer and winter capability periods for the given year.

Figure A-97: UCAP Sales and Prices in New York City
May 2017 to February 2019

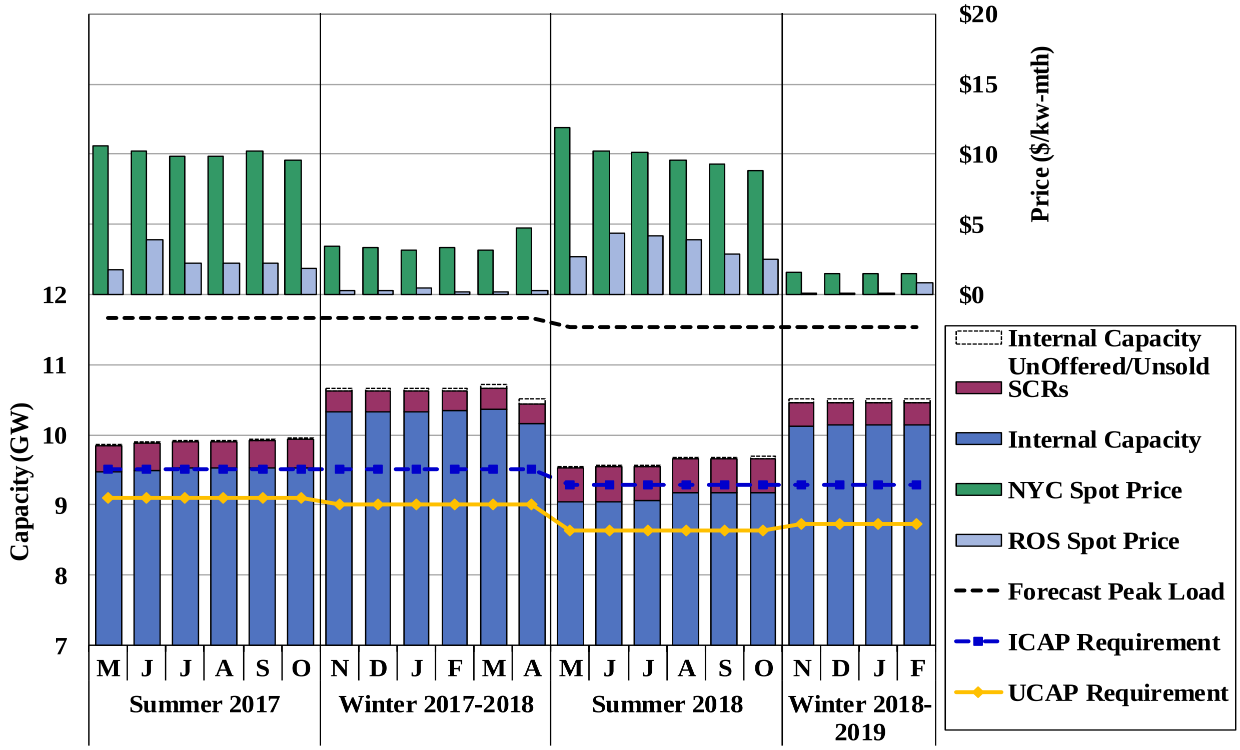


Figure A-98: UCAP Sales and Prices in Long Island
May 2017 to February 2019

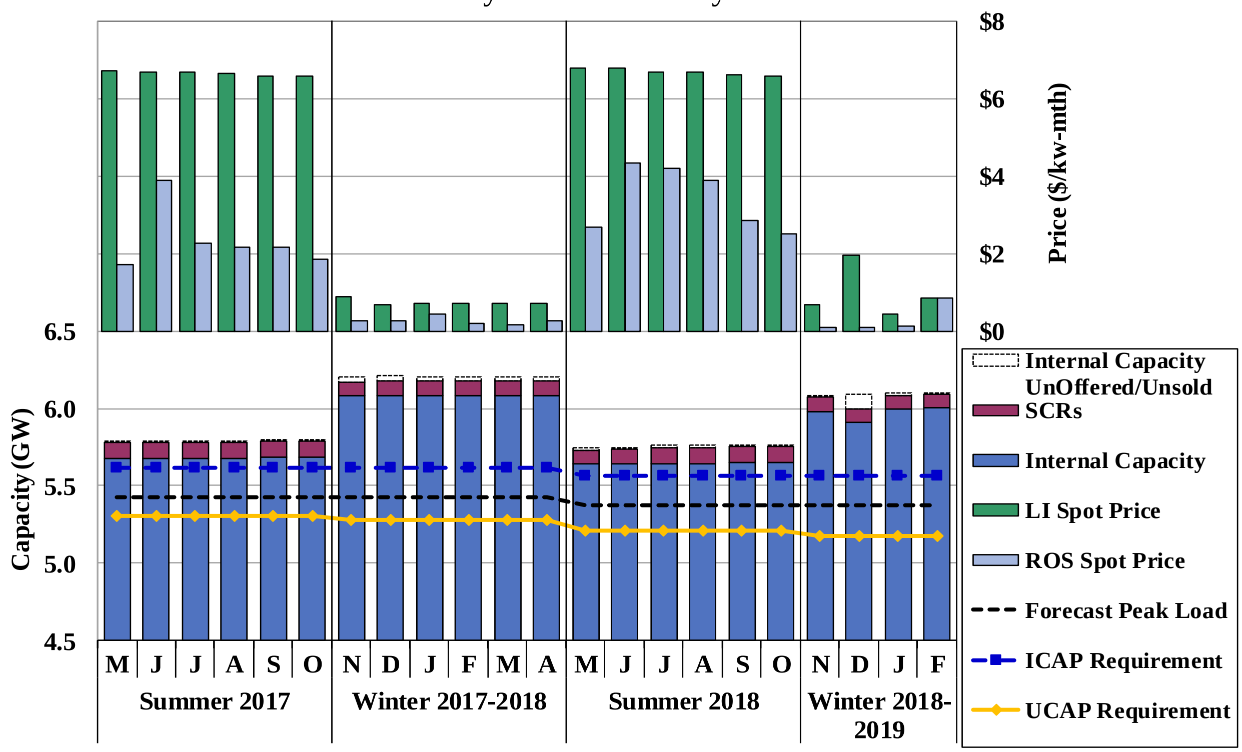
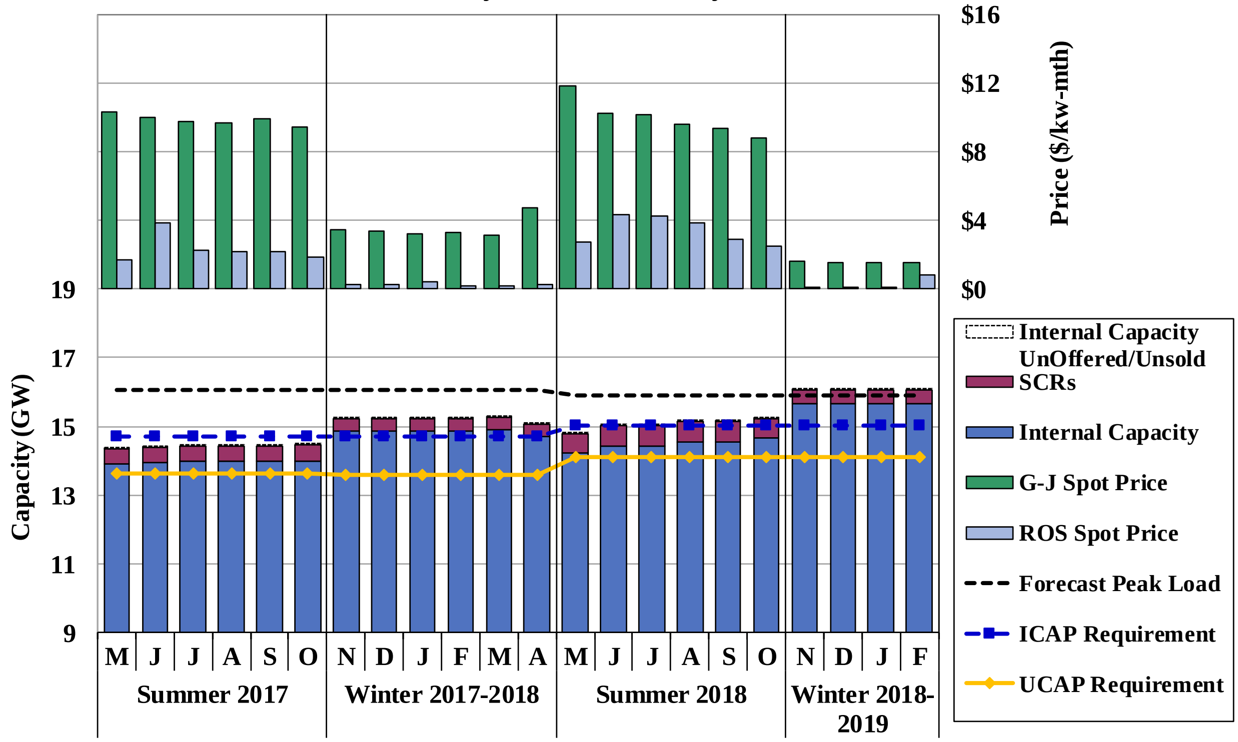


Figure A-99: UCAP Sales and Prices in the G-J Locality
May 2017 to February 2019



Key Observations: UCAP Sales and Prices in Local Capacity Zones

- As in the statewide market, seasonal variations substantially affect the market outcomes in the local capacity zones.
- The Summer UCAP spot prices changed only marginally in the three eastern capacity zones, during the 2018/19 Capability Year from the prior Capability Year. However, the year-over-year changes in winter prices varied significantly across the three Localities. Specifically:
  - New York City spot prices fell: (a) less than 1 percent to an average of $10/kW-month in the Summer 2018 Capability Period; and (b) 54 percent to an average of $1.54/kW-month in the Winter 2018/19 Capability Period.
  - Long Island spot prices rose: (a) 1 percent to an average of $6.70/kW-month in the Summer 2018 Capability Period; and (b) 30 percent to an average of $0.97/kW-month in the Winter 2018/19 Capability Period.
  - The G-J Locality spot prices: (a) increased 2 percent to an average of $10/kW-month in the 2018 Summer Capability Period; and (b) decreased 54 percent to an average of $1.54/kW-month in the Winter 2018/19 Capability Period.
- The spot prices in New York City fell largely because the Summer UCAP requirement fell by more than 460 MW due to a lower peak load forecast and a lower LCR (by 1

percentage point). This resulted in NYC clearing on the G-J Demand Curve in all 12 months of this capability year.

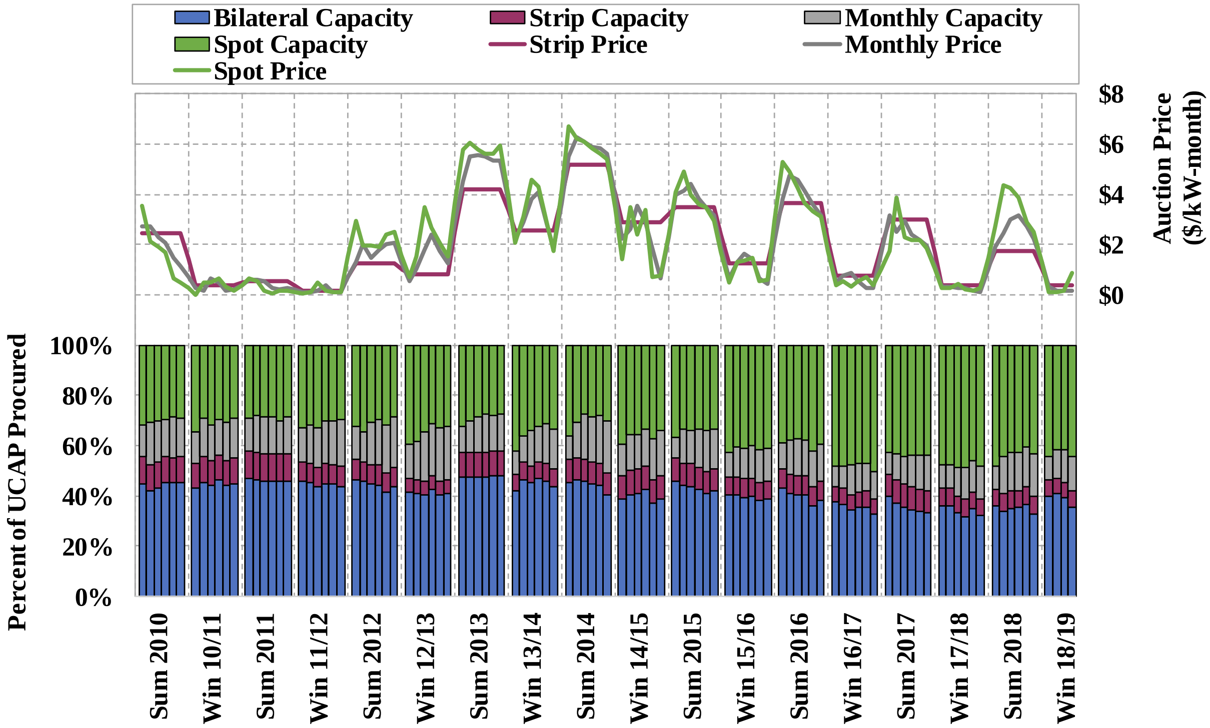
- The spot prices rose slightly in Long Island because:
  - Annual updates to the Net EAS revenues for the Long Island proxy unit resulted in a UCAP reference price that was 13 percent higher than the previous year's summer period.
  - On the other hand, the Long Island UCAP requirement fell by 85 MW primarily due to a reduced load forecast in the 2018/19 Capability Year.
- The spot prices in the G-J Locality increased marginally during the summer months but fell during the winter period because:
  - The LCR in G-J rose by 3 percentage points while the load forecast fell by roughly 140 MW. Consequently, the ICAP requirement in this region rose by 346 MW from the previous Capability Year.
  - The additions of the CPV Valley combined cycle unit and the Bayonne CTG9 and CTG10 units more than offset the reduction in supply from the Ravenswood GTs' IIFO.[375]
- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2018.

Figure A-100: Capacity Procurement by Type and Auction Price Differentials

Figure A-100 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 twelve capability periods. Bilateral price information is not reported to the NYISO and therefore not included in this image from a pricing perspective. 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 2010 capability period on a dollar-per-kilowatt-month basis.

[375] Unit capacity ratings of resources as shown are indicative of published summer ratings in the NYISO Load & Capacity Report for 2018.

Figure A-100: Auction Procurement and Price Differentials in NYCA
May 2010 – February 2019



Key Observations: Capacity Procurement and Price Comparison

- Almost 80 percent of the total UCAP in NYCA is procured via bilateral transactions (35 percent in Summer 2018) or in the spot market (44 percent in Summer 2018). The remaining capacity is procured through the strip (7 percent in Summer 2018) and monthly (15 percent in Summer 2018) auctions.[376]
  - The proportions of capacity procured through the four different mechanisms has remained in a relatively narrow range over the past twelve capability periods, with the procurement in the spot market increasing slightly at the expense of the other three mechanisms.
- The Summer 2018 saw the Spot Market prices average almost double what posted in the Strip Auction, likely due to the large variation in monthly net imports witnessed from the prior Summer capability period relative to expectations (see Figure A-94).

F. Cost of Reliability Improvement from Additional Capacity

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

376 These four numbers add up to 101% with the extra 1% a consequence of rounding error.

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 recently implemented a new methodology for determining the LCRs. The NYISO's methodology ("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/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-11: Cost of Reliability Improvement

Table A-11 shows the CRI in each zone based on the system at 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. 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 0.061. [377]

In addition to the CRI in each actual load zone, the table also shows the CRI at three additional locations that are represented as "dummy bubbles" in the GE-MARS topology. The bubbles shows in the table are: a) the CPV VEC bubble, which contains the 680 MW CPV Valley Energy Center combined cycle plant, b) the Athens Gilboa bubble, which contains 2.2 GW of generation from the Athens combined cycle and Gilboa hydro plants, and c) the J3 bubble representing Staten Island with 1.7 GW of generation from Arthur Kill and Linden Cogeneration plants as

[377] 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 220 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.

well as the Linden VFT-controlled and Linden-Goethals PAR-controlled interconnections to New Jersey.

The table shows the following for each area:

- *Net CONE of Demand Curve Unit* – Based on the uncollared Net CONE curves that were derived from the annual updates to the demand curves for the 2019/20 Capability Year.

- *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.[378]

- *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")* – This is the annual levelized investment cost necessary for a 0.001 improvement in the LOLE from placing capacity in the area.[379, 380] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

378 These values were obtained by starting with the system at Excess Level with an LOLE of 0.061 and calculating the change in LOLE from a 100 MW of perfect capacity addition in each area.

379 For example, for Zone F: $98/kW-year × 1000kW/MW ÷ (0.003LOLEchange/100MW) × 0.001LOLEchange = $2.4 million.

380 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.

Table A-11: Cost of Reliability Improvement
2019/ 20 Capability Year

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*
A	$98		0.059	0.0028	$3.5
B	$98		0.057	0.0041	$2.4
C	$98		0.057	0.0040	$2.4
D	$98		0.057	0.0040	$2.4
E	$98		0.057	0.0041	$2.4
F	$98	0.061	0.057	0.0040	$2.4
G	$148		0.056	0.0054	$2.7
H	$148		0.056	0.0055	$2.7
I	$148		0.056	0.0056	$2.6
J	$180		0.054	0.0079	$2.3
K	$134		0.055	0.0061	$2.2
Other Areas					
CPV VEC	$148		0.0563	0.005	$2.9
Athens Gilboa	$98	0.061	0.0582	0.003	$3.0
Staten Island (J3)	$180		0.0600	0.001	$12.9

<u>Key Observations: Cost of Reliability Improvement</u>

- The Optimized LCRs Method has reduced the range in CRI values across load zones when compared to previous years. Nevertheless, the range between the minimum CRI-value location (Long Island at $2.2 million per 0.001 events) and the maximum CRI-value location (Zone A at $3.5 million per 0.001 events) is still substantial.
  - The CRI for Zone K ($2.2 million per 0.001 events) continues to be lower than the CRI for Zone G ($2.7 million per 0.001 events). However, some have asserted that the Net CONE for Zone K was under-estimated in the last demand curve reset, suggesting that the true CRI for Zone K may actually be higher.
- The results reveal that there are substantial differences in the MRI values for specific areas within a capacity zone. In particular, the MRI for Staten Island is only 0.001, and is significantly lower than the Zone J MRI. The MRI for CPV VEC and Athens Gilboa areas are also lower than the capacity zone in which they are currently located. This disparity suggests that generation in these areas is overpriced relative to its reliability value.
- The CRI values for zones within the current configuration of capacity market zones (i.e. zones G-I and A-F) are relatively similar, with the notable exception of Zone A. However, the MRI and the Net CONE for each zone depend on several factors that could evolve in the future. For instance, the zonal MRIs could change significantly with retirement of a large plant like Indian Point or with increase in the UPNY-SENY transfer

capability. Similarly, gas pipeline congestion patterns could lead to large differences in the Net CONE values within a capacity market locality.[381]

- Such developments could lead to large disparities in the CRI values of different locations within a capacity locality. Such large disparities usually imply that a locality should be broken into multiple localities to ensure that capacity is priced and scheduled efficiently.

G. 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.[382]

Figure A-101: Breakdown of Revenues for Generation and Transmission Projects

Figure A-101 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") portion of the TOTS projects. 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 information presented in the figure is based on the following assumptions and inputs:

- The MSSC project is assumed to increase the UPNY-SENY transfer capability by 287 MW.[383]

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381 See comments of the Market Monitoring Unit in Commission Docket ER17-386-000, dated December 9, 2016.

382 See Recommendation 2012-1c in Section XI.

383 Although the MSSC project increase the limit for the Central-East interface, MARS results indicate that the MRI for this interface is zero in the current year. Our assumption for increase in UPNY-SENY transfer capability is based on the following - https://nyisoviewer.etariff.biz/viewerdoclibrary/Filing/Filing1033/Attachments/NYPA%20Trnsmttl%20Lttr%20Frml%20Rt%20Flng%2007.02.2015%20F.pdf.

We estimated the Gross CONE for the TOTS projects using the following inputs:

a) Carrying charge of 9.2 percent based on the WACC developed in the 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 https://www.utilitydive.com/news/new-york-finishes-transmission-project-to-access-440-mw-of-capacity/421104/).

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.

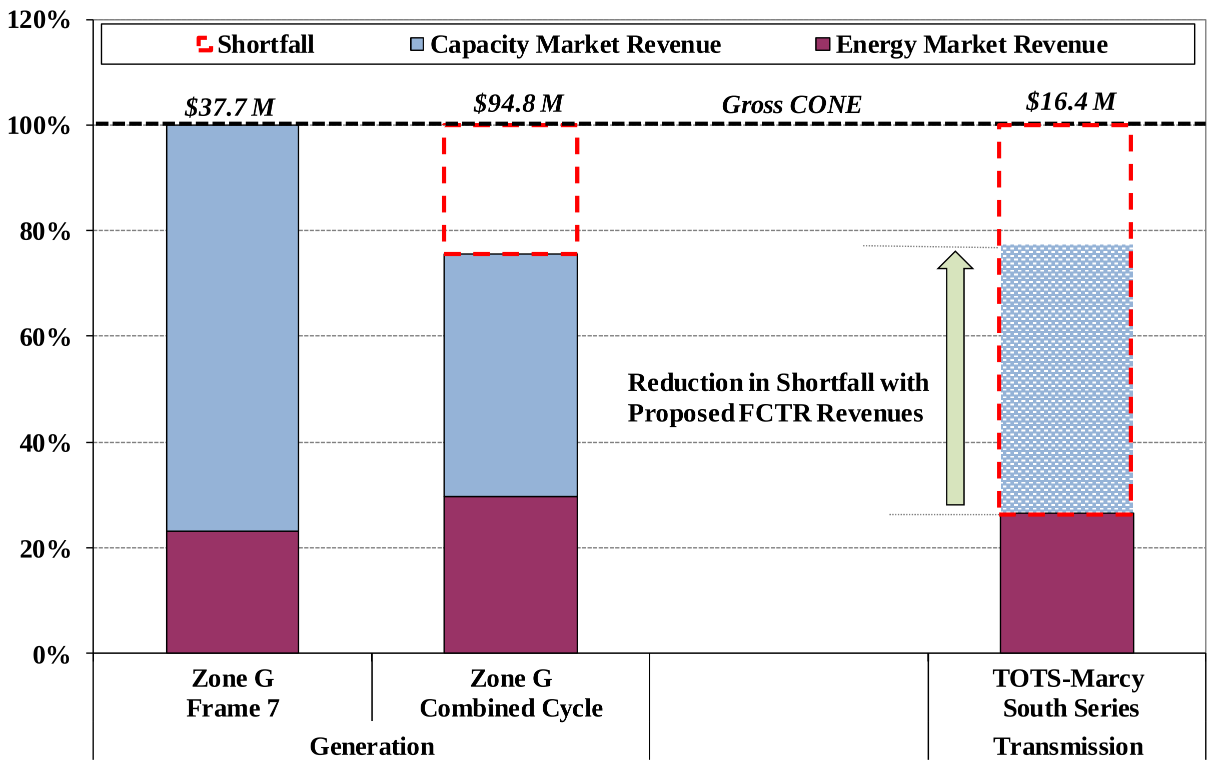
- The system is assumed to be at the long-term equilibrium that is modeled in the demand curve reset process, with each locality at its Excess Level. GE-MARS simulations of the 2018 IRM topology indicate that the estimated reliability benefit (reduction in LOLE) from increasing the transfer capability of the UPNY-SENY interface by 200 MW is 0.002 events per year.

- The FCTR revenues for the transmission project equal the product of the following three inputs:
  - The effect on the transfer limit of one or more interfaces (only UPNY-SENY in the case of the TOTS projects) from adding the new facility to the as-found system, and
  - The MRI of the increasing the transfer limit of UNPY-SENY, and
  - The value of reliability in dollars per unit of LOLE. Based on the results of the GE-MARS runs for the 2018 IRM topology, this value is assumed to be $2.9 million per 0.001 events change in LOLE.

- 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 2017 Demand Curve reset study, the TCCs were valued based on the energy prices during September 2013 through August 2016.

- The gross CONE, energy and capacity market revenues for the Zone G Frame and CC units are based on the 2017 Demand Curve reset study.

Figure A-101: Breakdown of Revenues for Generation and Transmission Projects



Key Observations: Financial Capacity Transfer Rights for Transmission Projects

- Figure A-101 illustrates the disadvantages that transmission projects have relative to generation (and demand response) in receiving compensation for the planning reliability benefits they provide to the system.

- Capacity market compensation has historically provided a critical portion of the incentive for generator entry and exit decisions.
  - The figures shows that capacity markets provide 46 to 77 percent of a new generator in Zone G and it is highly unlikely that a new generator would be built without this revenue stream.

- The results also illustrate the potential of FCTRs in incentivizing development of merchant transmission projects. In the absence of capacity payments, the MSSC project recoups only 27 percent of its annualized gross CONE. However, granting FCTRs to the project would have provided an additional 51 percent of the annualized gross CONE. These results indicate:
  - A major benefit of most generation and transmission projects is that they provide significant planning reliability benefits.
  - Generators receive high rates of compensation for the planning reliability benefits they provide in the capacity market.
  - However, transmission projects receive no compensation for such benefits through the market. Thus, it is unlikely that market-based investment in transmission will occur if transmission providers cannot receive capacity market compensation for providing planning reliability benefits.

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 units, (d) new onshore wind units, and (e) new offshore wind units (subsection C). 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 number of our recommendations (see Section XI) for enhancing real time markets would result in significant changes to the energy and reserve prices, and could impact the operation of various resources. In subsection D, we evaluate the potential impact of a subset of these recommendations on the net revenues of different types of resources under the long-run equilibrium conditions.

A. Gas-Fired and Dual Fuel Units Net Revenues

We estimate the net revenues the markets would have provided to three types of older existing gas-fired units and to the three types of new gas-fired units that have constituted most of the new generation in New York:

- *Hypothetical new units*: (a) a 2x1 Combined Cycle ("CC 2x1") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and

- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.

We estimate the historical net energy and ancillary services revenues for gas-fired units based on prices at two locations in Long Island, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone. We also use location-specific capacity prices from the NYISO's spot capacity markets. Future years' net energy and ancillary services and capacity revenues are based on zonal price futures for each individual zone. Energy and ancillary services revenues for units in the Central Zone, 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. 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 Hudson Valley zone that are downstream of the UPNY-SENY interface.

Table A-12 to Table A-15: 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 before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.

- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves.

- Combustion turbines (including older gas turbines) are committed in real-time based on RTC prices.[384] Combustion turbines 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 integrated 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 the maximum capability.

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384 Our method assumes that such a unit is committed for an hour if the average LBMP in RTC at its location is greater than or equal to the applicable start-up and incremental energy cost of the unit for one hour. This uses the RTC LBMPs posted on the NYISO's website.

- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability.
    - Combined-cycle units and new combustion turbines are assumed to use diesel oil, older gas turbines are assumed to use ultra-low sulfur diesel oil, and steam turbines are assumed to use low-sulfur residual oil.
    - During hourly OFOs in New York City and Long Island, generators are assumed to be able to operate in real-time above their day-ahead schedule on oil (but not on natural gas). Dual-fueled steam turbines are assumed to be able to run on a mix of oil and gas, while dual-fueled combined-cycle units and combustion turbines are assumed to run on one fuel at a time.
    - During hourly OFOs in New York City and Long Island, generators are assumed to offer in the day-ahead market as follows:

Table A-12: Day-ahead Fuel Assumptions During Hourly OFOs[385]

Technology	Gas-fired	Dual Fuel
Combined Cycle	Min Gen only	Oil
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- 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-13: Gas and Oil Price Indices and Other Charges by Region

Region	Gas Price Index	ransportation & Other Charges ($/MMBTU			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West	Dominion North	$0.27	$2.00	$1.50	10%
Central	Dominion North	$0.27	$2.00	$1.50	10%
Capital	Iroquois Zn2	$0.27	$2.00	$1.50	10%
Hudson Valley	50% Iroquois Zn2, 50% Millenium E	$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%

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered for all years. However, the older GT-30 unit is assumed not to have RGGI compliance costs because the RGGI program does not cover units below 25 MW.

385 **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.

- The minimum generation level is 454 MW for the CC 2x1 unit and 90 MW for the ST unit. At this level, the heat rate is 7453 btu/kWh for the CC 2x1 unit and 13,000 btu/kWh for the ST unit. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.

- We also use the operating and cost assumptions listed in the following tables:

Table A-14: New Gas-fired Unit Parameters for Net Revenue Estimates[386]

Characteristics	CC 2x1	LMS	Frame 7 with SCR	Frame 7 no SCR
Summer Capacity (MW)	668	202	230	230
Winter Capacity (MW)	704	218	230	230
Summer Heat Rate (Btu/kWh)	7028	9153	10193	10187
Winter Heat Rate (Btu/kWh)	6900	8993	10040	10020
Min Run Time (hrs)	4	1	1	1
Variable O&M - Gas (2018$/MWh)	$2.6	$5.8	$0.8	$0.2
Variable O&M - Oil (2018$/MWh)	$2.9	$10.0	$2.8	$1.6
Startup Cost (2018$)	$0	$0	$11,265	$10,998
Startup Cost (MMBTU)	3700	61	350	350
EFORd	2.50%	2.17%	2.17%	2.17%

Table A-15: Existing Gas-fired Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M (2018$/MWh)	$8.5	$4.8	$5.8
Startup Cost (2018$)	$6,387	$1,277	$552
Startup Cost (MMBTU)	2000	50	60
EFORd	5.14%	10.46%	19.73%

386 These parameters are based on technologies studied as part of the 2017 ICAP Demand Curve reset. The CC2x1 unit parameters are based on the Cost of New Entry Estimates for Combined Cycle Plants in PJM. The CONE estimate for gas-fired units in West Zone are based on data from Zone C in the 2017 ICAP Demand Curve reset study.

Figure A-102 and Figure A-103: Forward Prices and Implied Heat Rate Trends

We estimate the net revenues from 2019 to 2021 using forward prices for power and fuel, and forecasted capacity prices.[387] We developed the hourly day-ahead power price forecast for each zone by adjusting the 2018 LBMPs using the ratio of monthly forward prices and the observed monthly average prices in 2018.[388] We held the reserve prices for future years at their 2018 levels.

Figure A-102 shows the variation in the forward prices and implied marginal heat rates for Zone A and Zone G over a six month (July-Dec 2018) trading period. Figure A-103 shows the monthly forward power and gas prices for the 2019-2021 period along with the observed monthly average prices during the 2016-2018 period.

In general, there is considerable volatility in power and gas forward prices during the last two quarters of 2018. The zonal forward prices in Zone G have ranged from \$33 to \$43 per MWh while Zone A forward prices were in the \$26 to \$36 per MWh range. Therefore, we used the trailing 90-day average of the forward prices as of January 1st, 2019. In contrast, the implied marginal heat rates (and the spark spreads) have been reasonably stable over the last six months in all zones for 2019 and 2020 delivery years. However, the implied marginal heat rates for delivery year 2021 are significantly higher in all the zones. This is likely because of the following factors: a) retirement of both Indian Point units, and b) the futures market pricing in the possibility of a carbon price adder.

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387 We estimated the capacity prices for Summer and Winter periods of 2019, 2020, and 2021 by making incremental changes to the monthly spot capacity price in October 2018 and February 2019. The changes we made for each Capability Year are as following:

(a) Capability Year 2019/ 20: We updated the LCRs for zones J, G-J, LI, and NYCA to 82.8, 92.3, 104.1, and 117 percent, respectively based on the LCRs published by the NYISO.

(b) Capability Year 2020/ 21: We kept the IRM for NYCA same as 2019 at 117 percent and updated the LCR's for zones NYC, G-J, and LI to 83 , 91, and 105 percent, respectively, in line with LCRs assumed as part of the CY-17 BSM evaluations. In addition to the LCR changes, we adjusted supply stack by adding CVEC (950 MW) and removing IP-2 (990 MW).

(c) Capability Year 2021/ 22: We kept the IRM for NYCA same as 2019, and updated the LCRs for zones NYC, G-J, and LI to 85, 91.5 , and 104 percent respectively, in line with LCRs assumed as part of the CY-17 BSM evaluations. We also adjusted assumed supply stack for 2020 Capability Year by removing IP-3 (950 MW).

For power and gas prices in 2019 and 2020, we used OTC Global Holdings' forward strips published by SNL Energy.

388 Our net revenue estimates of gas-fired generation for the 2019-20 time period are based on zonal prices.

Figure A-102: Forward Prices and Implied Marginal Heat Rates by Transaction Date
2019, 2020, & 2021 Strip Prices from July to December 2018

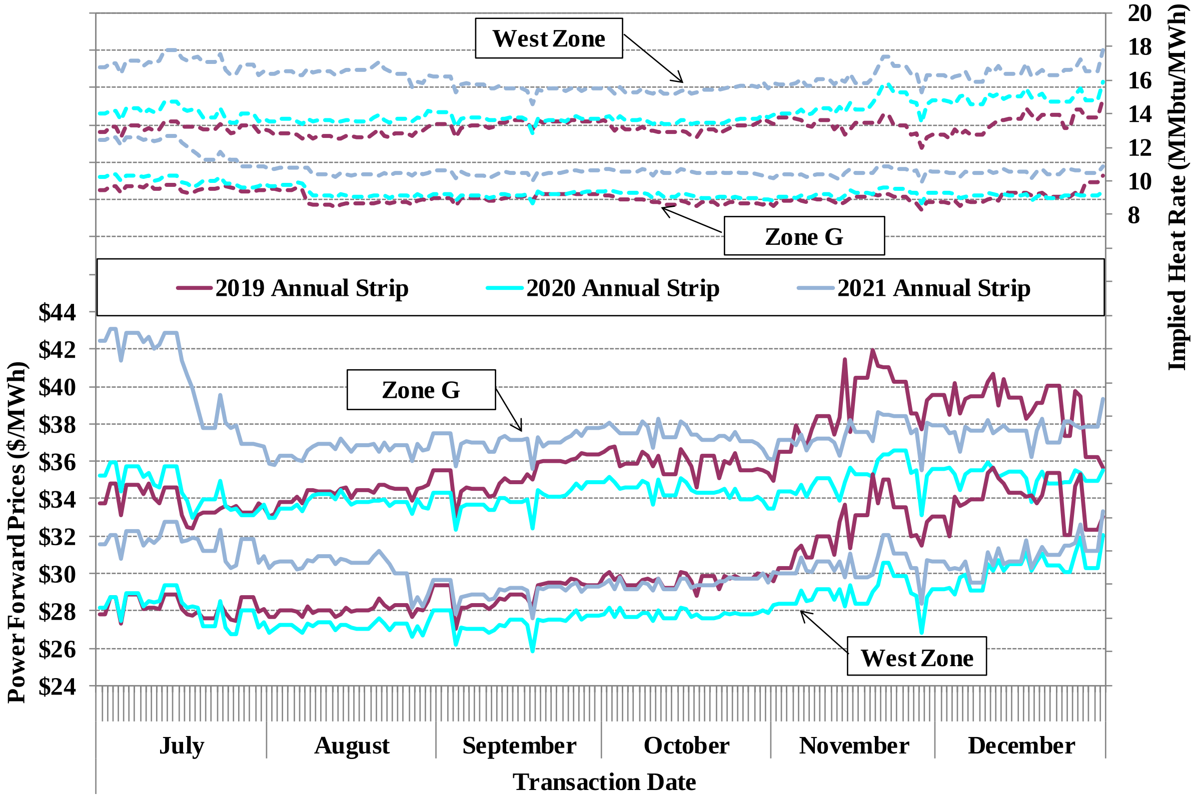
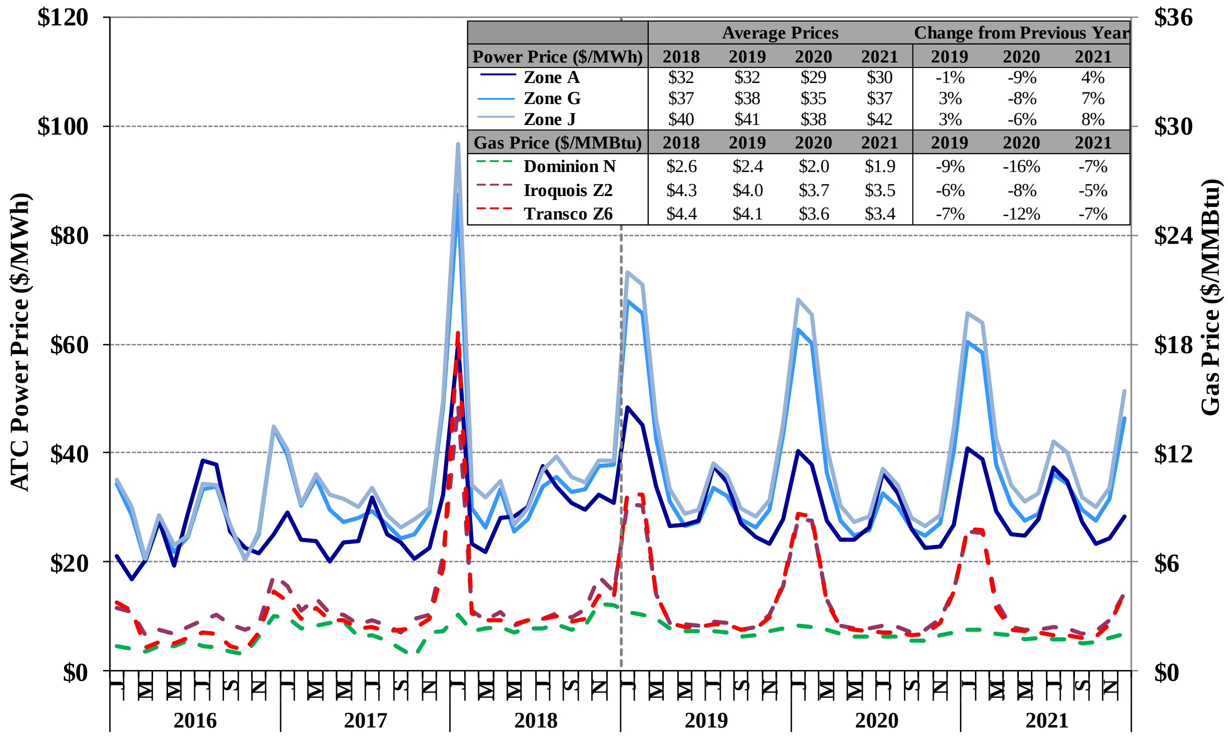


Figure A-103: Past and Forward Price Trends of Monthly Power and Gas Prices
2016 – 2021

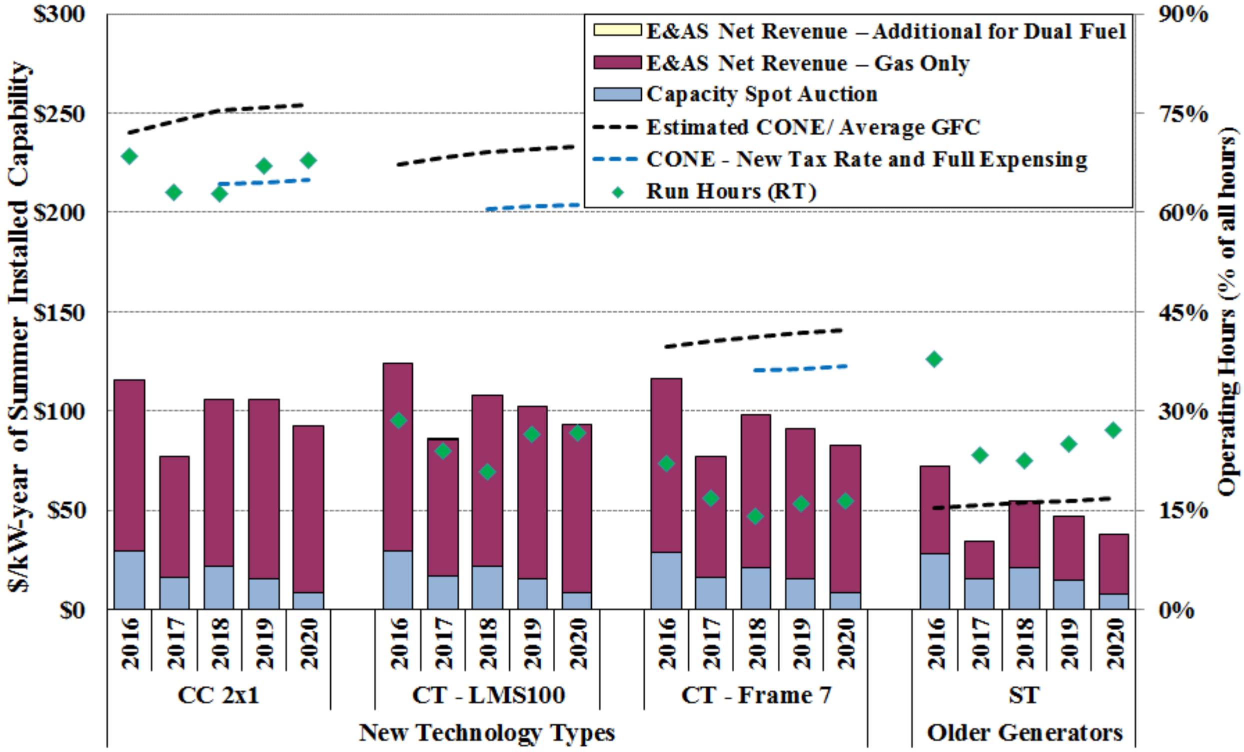


	Average Prices				Change from Previous Year		
Power Price ($/MWh)	2018	2019	2020	2021	2019	2020	2021
Zone A	$32	$32	$29	$30	-1%	-9%	4%
Zone G	$37	$38	$35	$37	3%	-8%	7%
Zone J	$40	$41	$38	$42	3%	-6%	8%
Gas Price ($/MMBtu)	2018	2019	2020	2021	2019	2020	2021
Dominion N	$2.6	$2.4	$2.0	$1.9	-9%	-16%	-7%
Iroquois Z2	$4.3	$4.0	$3.7	$3.5	-6%	-8%	-5%
Transco Z6	$4.4	$4.1	$3.6	$3.4	-7%	-12%	-7%

Figure A-104 to Table A-17: Net Revenues Estimates for Fossil Fuel Units

The following six figures summarize our net revenue and run hour estimates for gas-fired units in various locations across New York. They also indicate the levelized Cost of New Entry ("CONE") estimated in the Installed Capacity Demand Curve Reset Process for comparison.[389] Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-16 shows our estimates of net revenues and run hours for all the locations and gas unit types in 2018. Table A-17 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2018.

Figure A-104: Net Revenue & Cost for Fossil Units in West Zone
2016-2020



389 The CONE for the CC 2x1 units are based on publicly available cost information for the latest of the proposed large-scale CC projects in Long Island (Caithness II) and LHV (Cricket Valley Energy Center). For the CC2x1 unit in NYC, we show the cost of the CC 1x1 unit from the latest Demand Curve Reset study. We limit the capacity factor of the unit to 75 percent and assume that the unit will secure a property tax exemption. The CC 2x1 CONE shown for upstate zones is based on the CONE assumed for LHV. The GFCs for older generators are based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

Figure A-105: Net Revenue & Cost for Fossil Units in Central Zone
2016-2020

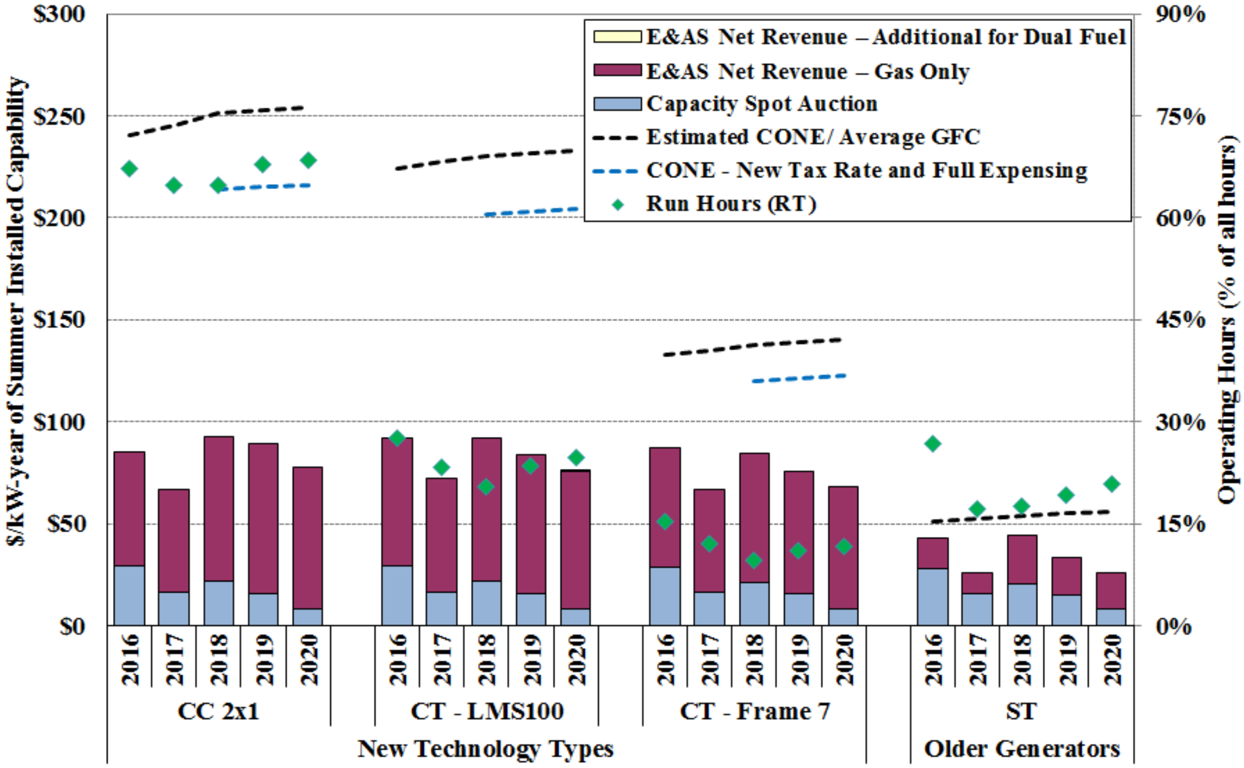


Figure A-106: Net Revenue & Cost for Fossil Units in Capital Zone
2016-2020

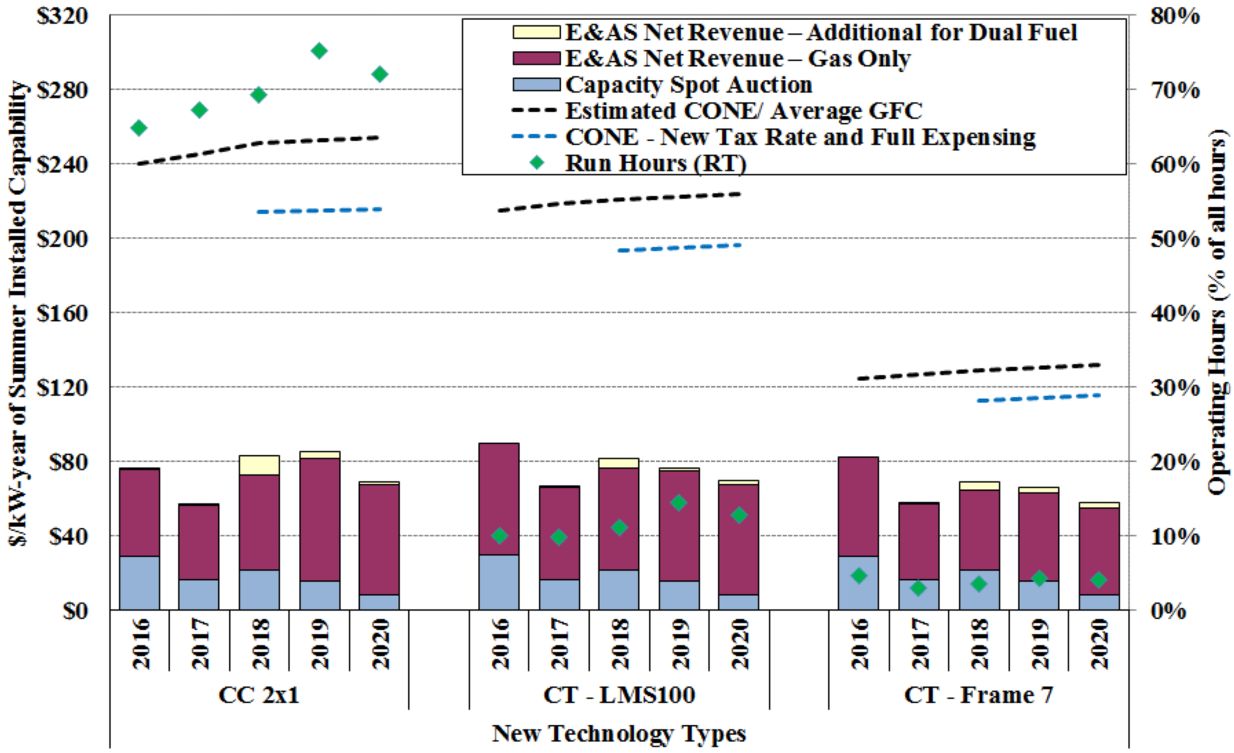


Figure A-107: Net Revenue & Cost for Fossil Units in Hudson Valley
2016-2020

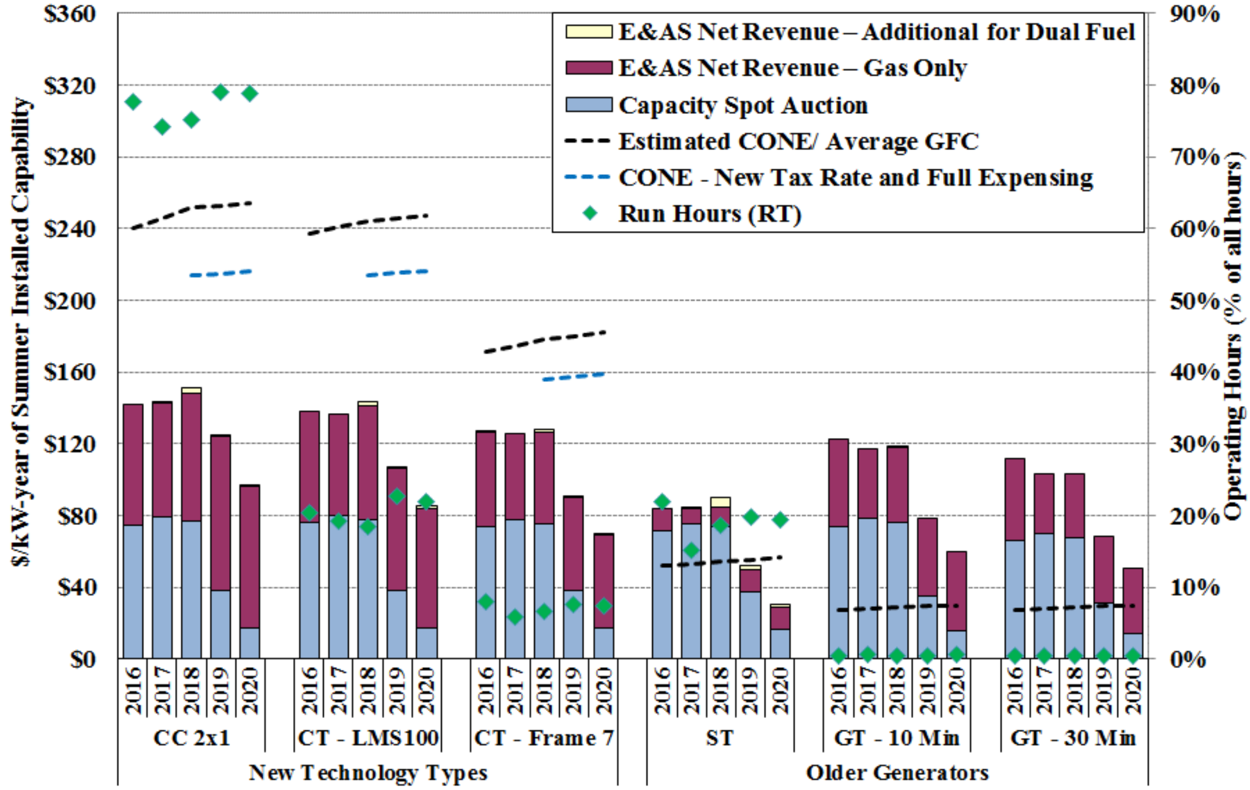


Figure A-108: Net Revenue & Cost for Fossil Units in New York City
2016-2020

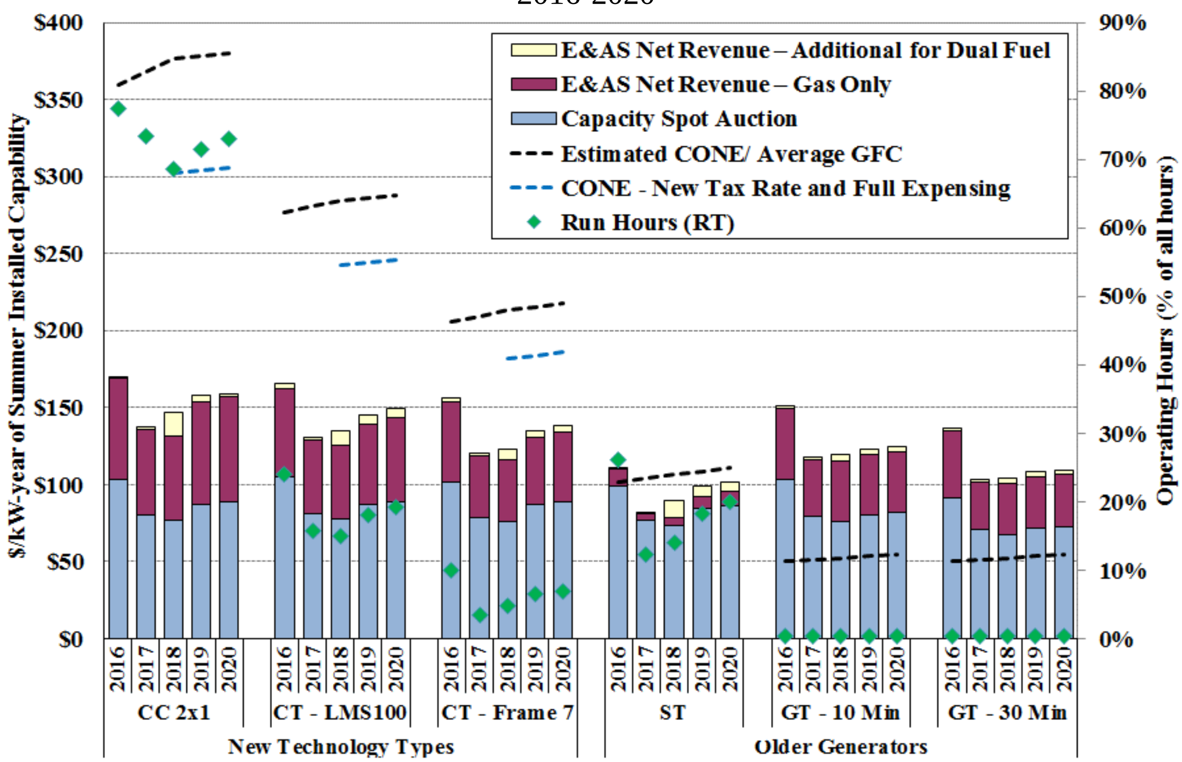


Figure A-109: Net Revenue & Cost for Fossil Units in Long Island
2016-2020

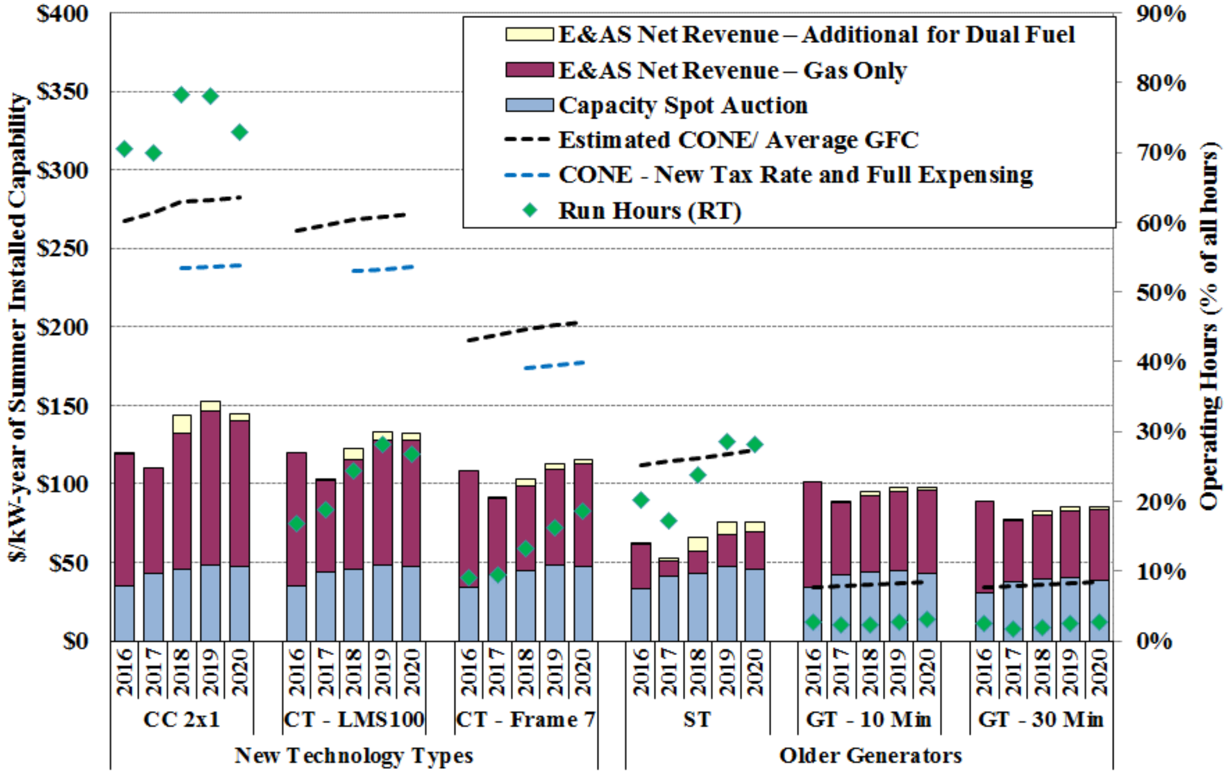


Table A-16: Net Revenue for Gas-Fired & Dual Fuel Units
2018

Location	Unit Type	Capacity	2018 Net Revenue ($/kW-yr)			Real Time Run Hours			
			Gas Only	Dual Fuel Additional	Dual Fuel Total	Gas Only Unit	DF Unit on Gas	DF Unit on Oil	DF Unit Total
Capital Zone	CC 2x1	$22	$51	$11	$83	5951	5879	187	6066
	CT - Frame 7	$21	$43	$4	$69	230	234	82	316
	CT - LMS100	$22	$55	$5	$82	856	848	131	979
Central Zone	CC 2x1	$22	$71	$0	$93	5676	5676	0	5676
	CT - Frame 7	$21	$63	$0	$84	840	840	0	840
	CT - LMS100	$22	$70	$0	$92	1783	1783	0	1783
	ST	$21	$24	$0	$44	1545	1545	0	1545
West Zone	CC 2x1	$22	$84	$0	$106	5501	5501	0	5501
	CT - Frame 7	$21	$77	$0	$98	1225	1225	0	1225
	CT - LMS100	$22	$86	$0	$108	1825	1825	0	1825
	ST	$21	$34	$0	$55	1970	1970	0	1970
Hudson Valley (Iroquois-Zn2 Gas)	CC 2x1	$77	$44	$9	$131	5231	5173	191	5364
	CT - Frame 7	$76	$42	$3	$121	219	219	47	266
	GT - 10 Min	$76	$42	$0	$118	21	21	2	23
	GT - 30 Min	$68	$34	$1	$103	22	22	1	22
	CT - LMS100	$78	$51	$4	$134	761	756	88	844
	ST	$74	$2	$8	$84	509	491	182	674
Hudson Valley	CC 2x1	$77	$71	$3	$151	6547	6468	111	6580
	CT - Frame 7	$76	$50	$2	$128	551	530	46	576
	GT - 10 Min	$76	$42	$0	$118	36	35	2	37
	GT - 30 Min	$68	$36	$0	$103	34	34	0	34
	CT - LMS100	$78	$64	$2	$144	1582	1550	69	1619
	ST	$74	$11	$6	$90	1558	1495	148	1643
Hudson Valley (Millenium E Gas)	CC 2x1	$77	$114	$0	$191	7341	7341	0	7341
	CT - Frame 7	$76	$87	$0	$163	1281	1281	0	1281
	GT - 10 Min	$76	$70	$0	$146	390	390	0	390
	GT - 30 Min	$68	$60	$0	$128	351	351	0	351
	CT - LMS100	$78	$100	$0	$178	2831	2831	0	2831
	ST	$74	$47	$0	$121	2777	2777	0	2777
Long Island	CC 2x1	$45	$87	$12	$143	6673	6673	190	6863
	CT - Frame 7	$45	$54	$4	$103	1103	1103	54	1156
	GT - 10 Min	$44	$48	$3	$95	203	203	2	204
	GT - 30 Min	$39	$41	$2	$83	167	167	1	168
	CT - LMS100	$46	$70	$7	$122	2045	2045	95	2140
	ST	$43	$14	$9	$66	1882	1856	227	2083
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$45	$170	$13	$228	7076	6979	197	7176
	CT - Frame 7	$45	$112	$8	$164	2423	2400	101	2501
	GT - 10 Min	$44	$87	$4	$135	557	557	47	604
	GT - 30 Min	$39	$75	$2	$117	438	438	15	453
	CT - LMS100	$46	$136	$10	$192	3115	3089	127	3217
	ST	$43	$69	$16	$128	4175	4076	255	4331
NYC	CC 2x1	$77	$54	$16	$147	5759	5736	276	6012
	CT - Frame 7	$76	$40	$7	$123	370	370	56	426
	GT - 10 Min	$76	$39	$4	$119	23	23	7	31
	GT - 30 Min	$68	$33	$3	$104	26	26	1	26
	CT - LMS100	$78	$47	$10	$135	1217	1217	103	1320
	ST	$74	$5	$11	$89	976	973	260	1233

Table A-17: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units
2018

Location	Unit Type	Gas-Only Units								Dual Fuel Units			
		E&AS Revenue ($/kW-yr)				Real Time Run Hours				E&AS Revenue ($/kW-yr)		Real Time Run Hours	
		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 4	Qtr 1	Qtr 4
Capital Zone	CC 2x1	$16	$10	$16	$9	1627	1305	1687	1332	$27	$9	1742	1332
	CT - Frame 7	$12	$11	$12	$9	23	35	168	3	$16	$9	106	3
	CT - LMS100	$16	$13	$13	$12	194	172	412	78	$22	$12	317	78
Central Zone	CC 2x1	$33	$10	$20	$8	1586	1206	1852	1032	$33	$8	1586	1032
	CT - Frame 7	$28	$11	$14	$10	317	169	323	31	$28	$10	317	31
	CT - LMS100	$0	$0	$0	$0	0	0	0	0	$0	$0	0	0
	ST	$17	$1	$4	$1	405	249	692	198	$17	$1	405	198
West Zone	CC 2x1	$31	$18	$27	$9	1500	1180	1820	1001	$31	$9	1500	1001
	CT - Frame 7	$27	$18	$20	$11	333	285	475	132	$27	$11	333	132
	CT - LMS100	$30	$22	$21	$14	468	394	648	315	$30	$14	468	315
	ST	$16	$7	$9	$1	385	498	828	259	$16	$1	385	259
Hudson Valley (Iroquois-Zone2 Gas)	CC 2x1	$11	$9	$17	$7	1395	1160	1673	1003	$21	$7	1528	1003
	CT - Frame 7	$11	$10	$12	$9	1	45	170	3	$14	$9	48	3
	GT - 10 Min	$13	$10	$9	$10	0	5	15	0	$13	$10	2	0
	GT - 30 Min	$10	$8	$8	$9	0	5	14	2	$11	$9	1	2
	CT - LMS100	$14	$12	$14	$11	104	188	416	54	$18	$11	187	54
	ST	$0	$0	$2	$0	46	97	367	0	$8	$0	210	0
Hudson Valley	CC 2x1	$27	$13	$21	$9	1843	1448	2003	1254	$30	$9	1875	1254
	CT - Frame 7	$15	$12	$13	$11	172	113	258	8	$17	$11	198	8
	GT - 10 Min	$13	$10	$9	$10	5	14	17	0	$13	$10	5	0
	GT - 30 Min	$11	$9	$8	$9	1	13	18	3	$11	$9	1	3
	CT - LMS100	$22	$14	$15	$13	406	398	628	150	$24	$13	443	150
	ST	$5	$2	$4	$1	283	415	739	121	$11	$1	368	121
Hudson Valley (Millenium E Gas)	CC 2x1	$56	$18	$26	$14	2034	1645	2110	1552	$56	$14	2034	1552
	CT - Frame 7	$44	$15	$16	$12	436	373	442	29	$44	$12	436	29
	GT - 10 Min	$40	$11	$9	$10	322	44	23	0	$40	$10	322	0
	GT - 30 Min	$33	$10	$8	$9	274	50	24	3	$33	$9	274	3
	CT - LMS100	$49	$17	$17	$16	772	774	912	374	$49	$16	772	374
	ST	$33	$5	$6	$2	628	805	1056	287	$33	$2	628	287
Long Island	CC 2x1	$23	$15	$26	$23	1754	1408	1942	1569	$34	$23	1944	1569
	CT - Frame 7	$11	$13	$18	$12	236	240	398	229	$15	$12	290	229
	GT - 10 Min	$11	$12	$14	$11	25	41	97	39	$14	$11	27	39
	GT - 30 Min	$9	$10	$13	$9	19	37	82	29	$11	$9	20	29
	CT - LMS100	$16	$17	$20	$16	463	461	627	494	$23	$16	558	494
	ST	$2	$2	$7	$3	332	384	694	471	$11	$3	533	471
Long Island (VS/ Barrett Load Pocket)	CC 2x1	$50	$21	$55	$44	1921	1465	2068	1623	$63	$44	2020	1623
	CT - Frame 7	$28	$16	$39	$29	541	385	900	597	$36	$29	618	597
	GT - 10 Min	$20	$13	$35	$19	79	76	298	104	$24	$19	126	104
	GT - 30 Min	$15	$12	$33	$15	55	65	240	78	$17	$15	70	78
	CT - LMS100	$35	$22	$42	$37	788	590	992	745	$46	$37	889	745
	ST	$16	$6	$27	$19	930	714	1460	1071	$32	$19	1086	1071
NYC	CC 2x1	$14	$11	$20	$9	1463	1226	1820	1250	$29	$9	1715	1250
	CT - Frame 7	$8	$10	$12	$10	15	116	225	14	$15	$10	70	14
	GT - 10 Min	$10	$10	$9	$10	0	5	18	1	$14	$10	7	1
	GT - 30 Min	$8	$8	$8	$9	0	6	17	3	$11	$9	1	3
	CT - LMS100	$11	$12	$14	$11	192	303	504	218	$21	$11	294	218
	ST	$0	$1	$3	$1	76	260	483	157	$11	$1	333	157

Key Observations: Net Revenues of Gas-fired and Dual Fuel Units

- *Year-Over-Year Changes* – The results indicate that the 2018 net revenues for gas-fired units were higher than the 2017 net revenues for all technology types and locations.
  - As discussed in section I of the Appendix, 2018 witnessed extreme cold weather in January, higher gas prices, and higher summer load levels, all of which contributed to higher energy prices. Consequently, the energy margins in 2018 were higher relative to 2017 in all the locations that we studied. In particular, the cold snap in January 2018 accounted for a majority of the year-over-year increase in net revenues.[390]
  - The decrease in capacity prices in Lower Hudson Valley and New York City zones (see subsection VII.E of the appendix) partially offset the increase in E&AS revenues of units located in these zones.[391] The capacity revenues in all other locations increased in 2018.
- *Estimated Future Net Revenues* - Given the current pricing of forward contracts, the net E&AS revenues of most units in the 2019 to 2020 timeframe appear to be similar or slightly higher than 2018. Ultimately, these estimates are uncertain because they depend on volatile power and gas forward prices. Forward price expectations are affected by expected retirements, new generator entry, transmission additions, clean energy mandates, and new gas pipeline development.
- *Incentives for New Units* - The 2018 net revenues for all the new technologies were well below the respective CONE estimates in all the locations we studied. There continues to be a significant amount of surplus installed capacity which, in conjunction with low demand, has led to net revenues being lower than the annualized CONE for all new hypothetical units in 2018. We discuss incentives for repowering existing units in subsection D.
- *Estimated Net Revenues for Existing Units* – Over the last three years, the estimated average net revenues of older existing gas-fired units were higher than their estimated going-forward costs ("GFCs") for most location-technology combinations, except for steam turbines in several zones.
  - Among older technologies, the estimated net revenues were highest for a GT-10 unit. In addition to capacity revenues, reserve revenues play a pivotal role in the continued operation of older GTs. This is particularly true for units whose EFORds are high or units which require higher capital expenditures than normal.[392] Therefore, adjusting

[390] For instance, the hypothetical combined cycle unit that we studied in Capital zone earned almost 80% of its increased revenues in January.

[391] The increase in capacity market revenues was sufficient to fully offset the smaller energy margin for the combined cycle unit located in Lower Hudson Valley.

[392] In 2018, some older GTs' were found to have EFORds that were well above the 10 to 20 percent level that we assumed for our generic older GTs. Figure A-95 shows that some of the GTs have EFORds that are

reserve revenues for the performance of operating reserve providers (as discussed in our recommendation 2016-2) could have a significant impact on: (a) the financial viability of these units and/or (b) the willingness of asset owners to incur the costs necessary to ensure their assets perform reliably.

- Steam turbine net E&AS revenues, unlike older GTs' revenues, are driven primarily by energy prices. Consequently, the net revenues of steam turbines in 2018 are slightly higher than in 2017. Simulation results for 2019-2020 suggest continued pressure for steam turbines to retire in all zones. However, retirement decisions are also impacted by other factors including individual unit GFCs, the owner's market expectations, existence of self-supply or bilateral contracts, etc.

- New environmental regulations may require GTs and STs in New York City to incur significant additional capital expenditures to remain in operation. First, the recently proposed rule by the New York DEC would require older GTs to install back-end controls (e.g., selective catalytic reduction) for limiting NOx and other pollutants by May 2023.[393] Second, the City of New York passed an ordinance preventing steam turbine generators from burning residual oil beginning in 2022, so steam turbines will have to install facilities for burning diesel oil in order to remain dual-fueled.[394]

- *Potential Reserve Market Revenues for Gas Turbines in 2018* – The 2018 results for gas turbines include substantial revenues from the sale of reserves. For instance, 10-minute reserve sales in New York City would have provided a typical GT-10 (average age of 45 years and 31 run hours in 2018) with over 90 percent of its total E&AS revenues of $43/kW-year. However, most of the 10-minute and 30-minute capable supply was scheduled far less frequently for reserves than the net revenue analysis would predict. Consequently, the actual reserve revenues of most peaking units were substantially lower than the simulated net revenues reported in this section.

- *Potential Implications of 2017 Tax Cuts and Jobs Act ("TCJA")* – A number of provisions of the TCJA legislation could affect the CONE estimates of new units. The results indicate that lowering the federal tax rate to 21 percent and allowing full expensing of equipment cost could lower the CONE by 15 to 18 percent. Such a reduction by itself would not be sufficient to render new entry economic based on 2018-2020 net revenues.[395]

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well in excess of 50 percent. Reserve revenues could be pivotal for a New York City unit with an EFORd of 40 percent.

393 See DEC's proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*, available at: http://www.dec.ny.gov/regulations/116131.html

394 See bill INT 1465-A, *Phasing out the use of residual fuel oil and fuel oil grade no.4 in boilers in in-city power plants*.

395 Several other provisions of tax bill (such as limits on interest deductions on debt and usage of net operating loss to reduce income) and capital market changes could limit the extent to which new projects can benefit from the new legislation.

- *Incentive for Dual Fuel Units* - Our results indicate that the additional returns from dual fuel capability were substantially higher in 2018 as compared to 2017, across several zones because of the significantly higher gas prices during the cold snap in January 2018. The average additional revenues for CC and ST units in recent years have generally been sufficient to incent dual fuel capability.[396] Dual-fuel capability provides a hedge against gas curtailment under tight supply conditions and reduces potential for fuel-related outages. Thus, most unit owners will continue to have incentives for installing and maintaining dual fuel capability (even in areas that do not mandate dual-fuel capability as a condition for gas interconnection).

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). For future years, bus prices are estimated by assuming the same basis differential as the historical year.

Figure A-110: Net Revenues for Nuclear Plants

Figure A-110 shows the net revenues and the US-average operating costs for the nuclear units from 2016 to 2021. 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.[397]

- 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 2015 through 2018.[398]

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396 See Analysis Group’s 2016 report on “Study to Establish New York Electricity Market ICAP Demand Curve Parameters”.

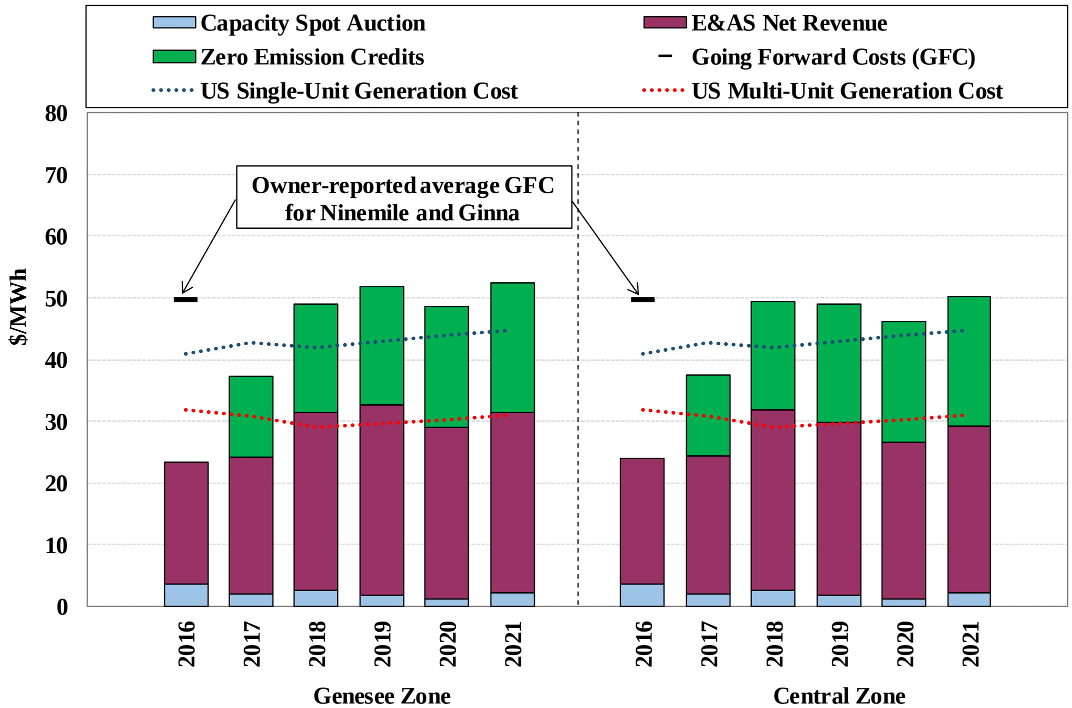
397 The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year to enable a year over year comparison of net revenues.

398 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See https://www.nei.org/CorporateSite/media/filefolder/resources/fact-sheets/nuclear-by-the-numbers.pdf. The weighted average GFC for Nine mile and Ginna was reported by the plant owners as part of the petition of Constellation energy nuclear group to initiate a proceeding to establish the facility costs for Ginna and Nine Mile Point nuclear power plants. See page 140 of the Clean Energy Standard Order issued on August 1, 2016 at https://www.nyserda.ny.gov/Clean-Energy-Standard.

- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[399] The ZEC price for compliance year 2017 (April 2017 to March 2018) is $17.54/MWh. For, compliance year 2018, the ZEC price is $17.48/MWh and for the subsequent tranche (April 2019 to March 2021), the DPS-estimated ZEC price is $19.59/MWh.

Figure A-110: Net Revenue of Existing Nuclear Units

2016-2021



Key Observations: Net Revenues of Existing Nuclear Units

- *Year-Over-Year Changes* – The estimated total net revenues for nuclear units in the upstate zones increased substantially from 2017 to 2018. In addition to increase in energy revenues, the net revenue increase was also driven by higher ZEC revenues.[400] The energy and capacity futures prices suggest that the net revenue of nuclear plants from the NYISO-administered markets over the next three years on average are expected to remain marginally lower than the 2018 levels.

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399 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 prices above a threshold of $39/MWh.

400 The upstate nuclear units received ZEC revenues only for nine month in 2017 (April through December).

- *Incentives for Existing Nuclear Plants* – The estimated 2018-2021 total net revenues of single-unit nuclear plants are above the US average of nuclear generation costs for upstate zones, due in large part to the ZEC revenues. ZEC revenues accounted for approximately 36 percent of the total revenues earned in 2018. The contribution of ZEC revenues is likely to increase in the future years as the DPS-estimated ZEC price is projected to increase for the 2019-2021 tranche.
  - Nuclear operating and decommissioning costs are highly plant-specific, and the retirement GFCs of the nuclear plants in New York may differ significantly from the US average operating costs. Therefore, the difference between the net revenues and GFCs may be smaller than the value implied in Figure A-110. In particular, nuclear units located in New York may be subject to higher labor costs and property taxes. Publicly available estimates for property taxes range from $2 to $3 per MWh. These factors in conjunction with the volatility of futures prices may render the nuclear plants in upstate New York (particularly single-unit) to be only marginally economic.

C. Renewable Units Net Revenues

We estimate the net revenues the markets would have provided to utility-scale solar PV and onshore wind plants in the Central, and Long Island zones, and to offshore wind plants interconnecting in the Long Island zone and Gowanus 345 kV bus in New York City.[401] For onshore wind units in Central and North zones, we calculated the net E&AS revenues using the capacity-weighted average of LBMPs at major wind installations in the zones.[402] For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-18: Cost and Performance Parameters of Renewable Units

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and onshore wind units is based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- Energy production is estimated using technology and location-specific hourly capacity factors for each month. The capacity factors are based on location-specific resource availability and technology performance data.[403]
- The capacity revenues for solar PV, onshore wind, and offshore wind units are calculated using prices from the spot capacity market. The capacity values of renewable resources

401 Nearly 2.9 GW of offshore wind projects in the interconnection queue is proposing to interconnect at the Gowanus 345kV substation.

402 We considered only the wind units whose nameplate capacity is larger than 100 MW.

403 The assumed capacity factors for solar PV, Onshore and Offshore wind units are sourced from NREL Annual Technology Baseline, 2018 available at : https://atb.nrel.gov/electricity/2018/index.html

are based on the factors (30, 2, and 38 percent for Winter Capability Periods and 10, 46, and 38 percent for Summer Capability Periods for onshore wind, solar PV, and offshore wind, respectively) specified in the March 2019 NYISO Installed Capacity Manual.[404]

- We estimated the value of Renewable Energy Credits ("RECs") produced by utility-scale solar PV, onshore wind, and offshore wind units using the weighted-average prices of RECs from the NYSERDA's Main Tier program procurements for 2016 and NYSERDA's Renewable Energy Standard ("RES") Tier 1 REC procurement program for 2017 through 2019. Future REC prices are derived by inflating the 2019 Tier 1 REC sale price.[405]

- Solar PV, offshore wind, and onshore 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 fraction of a unit's eligible investment costs depending on the resource type, and is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.[406] We

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404 The capacity value for renewable resources are available in Section 4.5.b of the ICAP Manual in the tables labeled "Unforced Capacity Percentage – Wind" and "Unforced Capacity Percentage – Solar." See https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

405 For more information on the recent RES Tier 1 REC procurements, see https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/REC-and-ZEC-Purchasers/2018-Compliance-Year. The 2019 REC price of $22.43/MWh for the 2019 compliance year, for the sale of the RECs between NYSERDA and the LSEs.

406 For solar PV, the ITC is 30 percent of the total eligible investment costs for projects that commence construction by end of 2019. It will step down to 26 percent for projects starting construction in 2020 and 22 percent for projects starting construction in 2021. However, as per the recently released IRS guidelines, the solar PV developers can safe harbor their investments for a maximum of four calendar years and receive ITC. For example, a project that commences construction in 2019 and comes online in 2023, will be considered to satisfy the continuity Safe Harbor, and thus will receive the full 30 percent ITC, see https://www.irs.gov/pub/irs-drop/n-18-59.pdf. Consequently, we assumed 30 percent ITC for solar PV in our analysis.

For offshore wind, the ITC is 30 percent of the total eligible investment costs for projects that commence construction by end of 2016. Thereafter it will reduce to 24 percent for projects starting construction in 2017, 18 percent for projects starting construction in 2018, and 12 percent for projects starting construction in 2019, post which the ITC will reduce to zero. Consequently, we assumed 30 percent ITC for unit coming online between 2016 and 2019, 24 percent for unit coming online in 2020, and 18 percent for unit coming online in 2021.

The Production Tax Credit is also scheduled to step down by 20 percent each year starting 2017 i.e., wind facilities commencing construction in 2017 will receive 80 percent PTC, commencing construction in 2018 will receive 60 percent PTC, and commencing construction in 2019 will receive 40 percent PTC. However, like solar PV, developers of onshore wind can safe harbor their investments for a maximum of four calendar years and receive PTC. Thus, we assume 80 percent PTC for a unit coming online in 2021, and 100 percent PTC for units coming online before 2021. 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.

incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[407]

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-18 shows cost estimates for solar PV, onshore wind and offshore wind units we used for a unit that commence operations in 2018. The data shown are largely based on NREL's 2018 Annual Technology Baseline.[408] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units. The CONE for renewable units was calculated using the financing parameters and tax rates specified in the most recent ICAP demand curve reset study.

407 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. We assumed that these units will be subject to the property tax treatment that is specified in the most recent ICAP demand curve reset study.

408 See NREL, 2018, *Annual Technology Baseline and Standard Scenarios*, https://atb.nrel.gov/electricity/2018/index.html

The assumed investment costs and fixed O&M costs for solar PV and onshore wind are based on the 2018 NREL ATB (Mid) values. The DC investment cost for solar PV was converted to AC basis based on the assumed PV system characteristics as outlined in the CES Cost Study (see page 166 of the CES Cost Study). For onshore wind units, we used capex values corresponding to TRG-5 in Central and LI zones. For offshore wind, these costs are based on 2018 Offshore Wind Policy Options Paper. See https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan/Studies-and-Surveys.

For onshore wind, US average investment costs were adjusted to New York conditions using technology-specific regional cost regional multipliers used in the EIA's AEO and the CES Cost Study. See "Capital Cost Estimates for Utility Scale Electricity Generating Plants", available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Regional multiplier for solar PV was utilized from ReEDS input data used for the 2018 NREL ATB analysis.

A labor cost adjustment factor of 1.1, intended to represent regional labor cost differences (based on the CES Cost Study), was applied to the Fixed O&M costs.

The assumed investment cost trajectory over the years for onshore wind and solar PV units was assumed to follow the technology-specific CapEx trajectory specified in the 2018 NREL ATB.

The assumed investment cost estimates also include interconnection costs. Interconnections costs for wind and solar PV units can vary significantly from project to project. For upstate solar PV and onshore wind the interconnection cost of $19/kW and $22/kW respectively were sourced from NREL ATB 2018. For offshore wind unit in LI zone, interconnection cost of $1176/kW was obtained from the 2018 Offshore Wind Policy Options Paper (see page 83 of the paper available at https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan/Studies-and-Surveys). We assume construction lead time (i.e. time taken by a unit from commencement of its construction to commercial operation) of 1 year for solar PV plant and 3 years for onshore and offshore wind plants.

Table A-18: Cost and Performance Parameters of Renewable Units

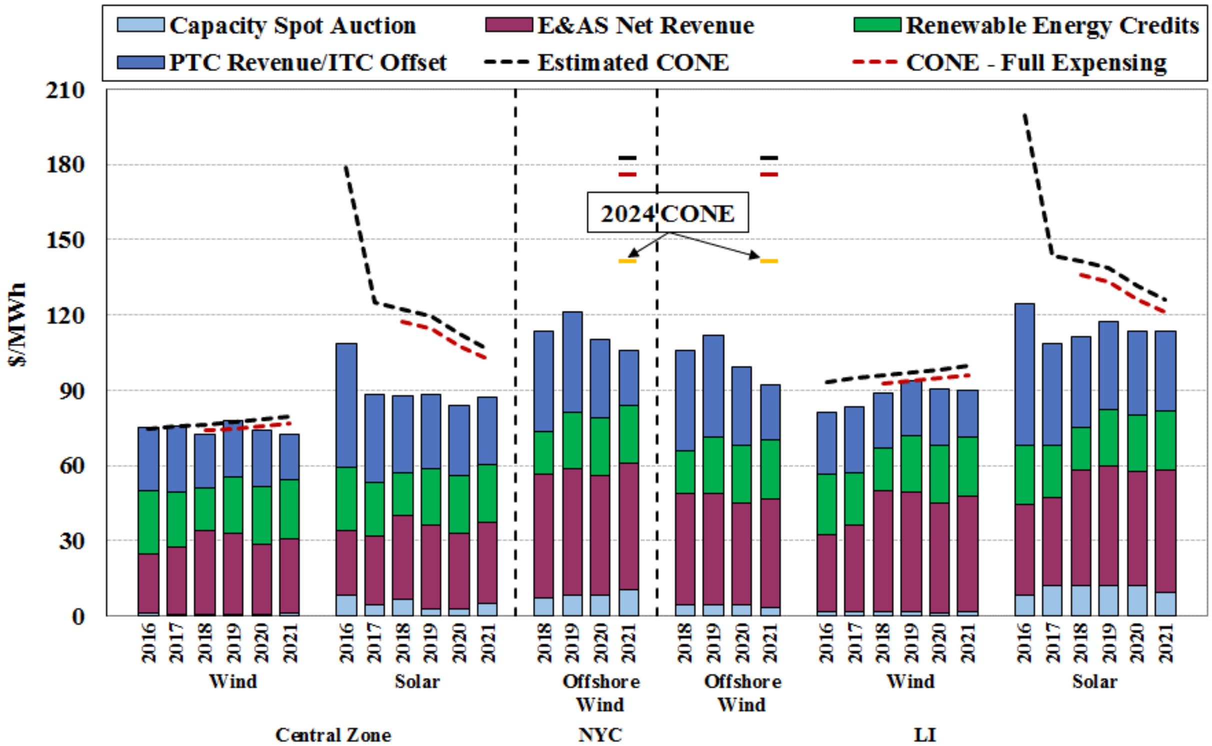
Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2018$/kW AC basis)	*Upstate NY*: $1550 *Long Island*: $1998	*Upstate NY*: $1750 *Long Island*: $2650	*NYC/Long Island* : $5660
Fixed O&M (2018$/kW-yr)	$13	$58	$139
Federal Incentives	ITC (30%)	PTC ($24/MWh)	ITC (30%)
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	Upstate NY: 16.4% LI: 17.9%	Upstate NY: 36.0% LI: 39.9%	NYC/LI: 45.9%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 10% Winter: 30%	Summer: 38% Winter: 38%
Renewable Energy Credits (Nominal $/MWh)	***2019 -*** $22.43 ***2018 -*** $17.01 ***2017 -*** $21.16 ***2016*** - $24.24		

Figure A-111: Net Revenues of Solar, Onshore Wind and Offshore Wind Units

Assuming the operating and cost parameters shown in the table above, Figure A-111 shows the net revenues and the estimated CONE for each of the units during years 2016-2021.

Figure A-111: Net Revenues of Solar, Onshore Wind and Offshore Wind Units[409]

2016-2021



Key Observations: Net Revenues of New Utility-Scale Solar PV, Onshore Wind, and Offshore Wind Plants

- *Net Revenues from NYISO Markets* – Given the relatively low capacity value of renewable resources, energy market revenues constitute a large majority of the revenues these units receive from the NYISO markets. Consequently, the estimated net revenues from the NYISO markets for all renewable units increased from 2017 to 2018 in all the locations we studied. Given the future power prices and the estimated capacity prices, the 2019-2021 revenues from the NYISO markets of all renewable units are likely to decrease or remain flat relative to their 2018 levels.

- *Role of State and Federal Incentives* – Renewable energy projects in New York receive a significant portion of their net revenues from state and federal programs in addition to revenues from the markets administered by the NYISO. The results indicate that the contributions of state and federal programs to the 2018 net revenues range from 48 percent to 60 percent for a new solar PV project and 44 percent to 60 percent for a new onshore wind project.

  - As with the new gas-fired units, the TCJA could also benefit renewable energy projects by lowering their CONE. However, as shown in the Figure A-111, the

409 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.

reduction in CONE is smaller than that of gas-fired units, largely because of the eligibility of renewables to accelerated depreciation benefits under current rules.

- *Incentives for Onshore Wind Units* – The estimated net revenues of the generic onshore wind units were likely to be marginally sufficient to cover their CONE in 2018 through 2021.[410] The returns from individual projects would depend on several additional factors such as REC prices and procurement targets, resource potential at the project sites, curtailment risk, and future cost declines.[411]

- *Incentives for Utility-scale Solar PV Units* – The results indicate that the net revenues of a solar PV unit would be insufficient to meet the estimated CONE of a project coming online in 2018 in all the locations studied. The investment costs for solar PV units have dropped significantly in the past few years, and are expected to drop further in the near future.[412] As a result, the shortfall of net revenues (relative to the CONE) of solar PV is likely to reduce considerably in the near future.

- *Incentives for Offshore Wind Units* – Offshore wind plants have relatively high capacity factors and capacity value. Consequently, the net revenues of these units are the highest on a $/kW-year basis among all the renewable units we studied. Based on the revenue streams considered, the estimated net revenues of the generic offshore wind units are considerably lower than the CONE in Long Island and New York City. However, the costs of developing offshore wind projects is projected to decline rapidly in the near future, and hence, the shortfall in net revenues is likely to be smaller than the estimated shortfall for 2021. Moreover, the economics of any individual project would depend on several additional factors that include procurement design, individual site characteristics, REC prices/ policy targets, ownership of project and associated transmission lines, and economies of scale.[413]

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410 Over 1,050 MW of wind projects in West and Central zones were awarded REC contracts as part of NYSERDA's 2017 and 2018 Renewable Energy Standard Solicitation. See https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts

411 The contracts for RECs are fixed and could be up to 20 years long. In addition, the benefits to renewable units from federal incentives are less volatile than the NYISO-market revenues. Therefore, the overall risk profile of the revenues of a renewable units in New York could be considerably different from that of a merchant generator. In the CES Cost Study, the DPS Staff assumed that longer term fixed REC contracts would result in a WACC of 6.99 percent. This could lower the CONE of a generic onshore wind, offshore wind, and solar PV units by roughly 10, 13, and 11 percent, respectively.

412 NREL reports a 28 percent decrease in capex for the utility-scale PV projects that were built in Q1 of 2017 over Q1 of 2016. See https://www.nrel.gov/docs/fy17osti/68925.pdf

413 For instance, the price for recently executed offshore wind contracts has varied widely – a) $160/MWh for the 90-MW South Fork Project in Long Island, b) $132/MWh for the 120-MW Skipjack and 248 MW projects in MA, and c) $74/MWh for the 400 MW Vineyard wind project in MA

D. Energy & Ancillary Services Pricing Enhancements Impacts on Investment Signals

Section XI of the report discusses several recommendations that are aimed at enhancing the pricing and performance incentives in the real-time markets. Implementing these recommendations would improve the efficiency of energy and reserve market prices, and help direct investment to the most valuable set of resources. In this subsection, we illustrate the impacts of implementing a subset of our real-time market recommendations on the long-term investment signals of various resource types in several Zone J locations.

We modeled the net revenue impact of five different enhancements to real-time pricing. We estimated their impact by adjusting the 2018 energy and reserve prices and/or individual unit net revenues in accordance with the following assumptions:

- Compensate operating reserve units that provide congestion relief ("2016-1") – We estimated the increase in 10-minute reserve prices at locations where 10-minute reserve providers can help relieve N-1 transmission congestion.[414]
- Discount reserve revenues to reflect performance ("2016-2") – Based on the recent historic performance of GTs in responding to the NYISO's start-up instructions, we discounted the reserve revenues that an average GT-30 unit would receive by 30 percent, and discounted the poor performers, that are at a higher risk of leaving the market, by 70 percent.
- Model local reserve requirements in New York City load pockets ("2017-1") – We estimated the impact of this recommendation by increasing the DA energy and reserve prices by an amount equal to the BPCG per MW-day of the UOL for DARU and LRR-committed units.[415, 416]
- Consider modifying operating reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP ("Pay For Performance") capacity market rules ("2017-2") – The net revenue impact is estimated assuming five hours of reserve shortage affecting southeast New York with an average clearing price increase of $2,000 per MWh.
- Model incentive payments to the units having the capability of instantaneously switching over from gas to oil fuel supply – We model this benefit by estimating the impact on LBMPs that would be paid to generators that would remain online and available one minute after a sudden loss of gas supply if such a product was cleared considering the incremental marginal cost of steam units burning a blend of oil and gas for reliability.

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414 See Section XI.B of the report.

415 See Section V.J of the Appendix.

416 The estimated price adders are applied proportionally to hours with reliability needs.

Table A-19 to Table A-20: Assumptions for Operating Characteristics of Repowered Combined Cycle and Grid-scale Storage Units

The technologies we considered for this analysis and their assumed operating characteristics are as follows:[417]

- Frame-7, GT-30, and ST Units – The operating characteristics and CONE/ GFCs for these units are identical to the assumptions we made in Subsections A and C.

- Repowered Fast-Start Combined Cycle Unit – We studied a 1x1 fast-start CC that could be built by repowering an existing or retired generation facility in New York City. The operating characteristics of this unit are summarized in Table A-19. The modeled 1x1 fast-start CC unit has a slightly higher heat rate than the 2x1 CC modeled in Subsection A. But, unlike the 2x1 CC unit, it is capable of providing 10-min non-spin reserves when offline.

Table A-19: Operating Parameters and CONE of Repowered Fast-start CC[418]

Characteristics	CC 1x1
Summer Capacity (MW)	240
10-min Non-spin Summer Capability (MW)	126
Average Summer Heat Rate (Btu/kWh)	8040
Min Run Time (hrs)	4
CONE (2018$/kW-yr)	$268

- Grid-scale Storage – We studied a grid-scale storage unit with a power rating of one MW and four hours of energy storage capacity. The unit is assumed to operate under the NYISO-managed mode, i.e. the injections and withdrawals are optimized over 24 hour period in the day ahead market.[419] Additionally, the unit is considered to settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule. The costs and operating characteristics of this unit are summarized in Table A-20.

417 The CONE/ GFCs estimates for new technologies correspond to units that would be able to commence operations in 2018.

418 The Gross CONE for repowered CC-FAST unit is estimated by discounting the Gross CONE of the CC 1x1 unit from the latest Demand Curve Reset study by roughly 25 percent. This adjustment is based on review of recent project cost information in New York and New England. The operating parameters are based on NRG Energy's filing with DEC on Astoria Repowering Project. The DEC filing can be found here: https://www.dec.ny.gov/docs/permits_ej_operations_pdf/pp1.pdf

419 The storage unit is assumed to be scheduled for a maximum of three hours in the day ahead market. This ensures that the unit is available to fulfill its day-ahead reserve commitment in real-time.

Table A-20: Operating Parameters and CONE of Storage Unit[420]

Characteristics	Storage
Gross CONE (2018$/kW-yr)	$301
Technology	Li-ion Battery
Service Life (Years)	20
Withdrawal (4 Hrs)	Lowest priced hours between 12am and 12pm
Injection (4 Hrs)	Highest priced hours between 1pm and 11pm
Reserve Selling Capability	10-min spin
Roundtrip Efficiency + EFORd	80%
Capacity Value	90%

Figure A-112: Impacts of Real Time Pricing Enhancements on Net Revenues of NYC Demand Curve unit under Long-term Equilibrium Conditions

In addition to improving the efficiency of energy and reserve prices, implementing real time market enhancements could also shift payments from capacity to energy markets. Under long-term equilibrium conditions, an increase in the E&AS revenues of the demand curve unit would translate into reduced capacity prices for all resources operating in the market.

To determine the impact on Annual ICAP Reference Value, we estimated Net CONE of the Frame unit under two scenarios with the system at the tariff-prescribed excess level conditions modeled in the ICAP demand curve reset.[421] Figure A-112 shows the incremental impact of each recommendation on the change in net revenues of the Frame unit under the long-term equilibrium conditions. The figure also shows the total increase in the Frame unit's net revenues, which would result in an equivalent decrease in the Net CONE that is used for determining the ICAP Demand Curve.

420 See EPRI's report "Energy Storage Cost Summary for Utility Planning". The overnight cost considered in the report does not include costs for project development, warranty extension, Insurance and contingency. These excluded costs were supplemented from Lazard's report on "Levelized Cost of Storage 2017".

421 We estimated the energy prices under the long-term equilibrium conditions by applying to LBMPs the Level of Excess-Adjustment Factors that are used in the annual updates to ICAP demand curve parameters. See Analysis Group's 2016 report on "Study to Establish New York Electricity Market ICAP Demand Curve Parameters".

Figure A-112: Impact of Pricing Enhancements on Net Revenues of NYC Demand Curve Unit

At Level of Excess Conditions

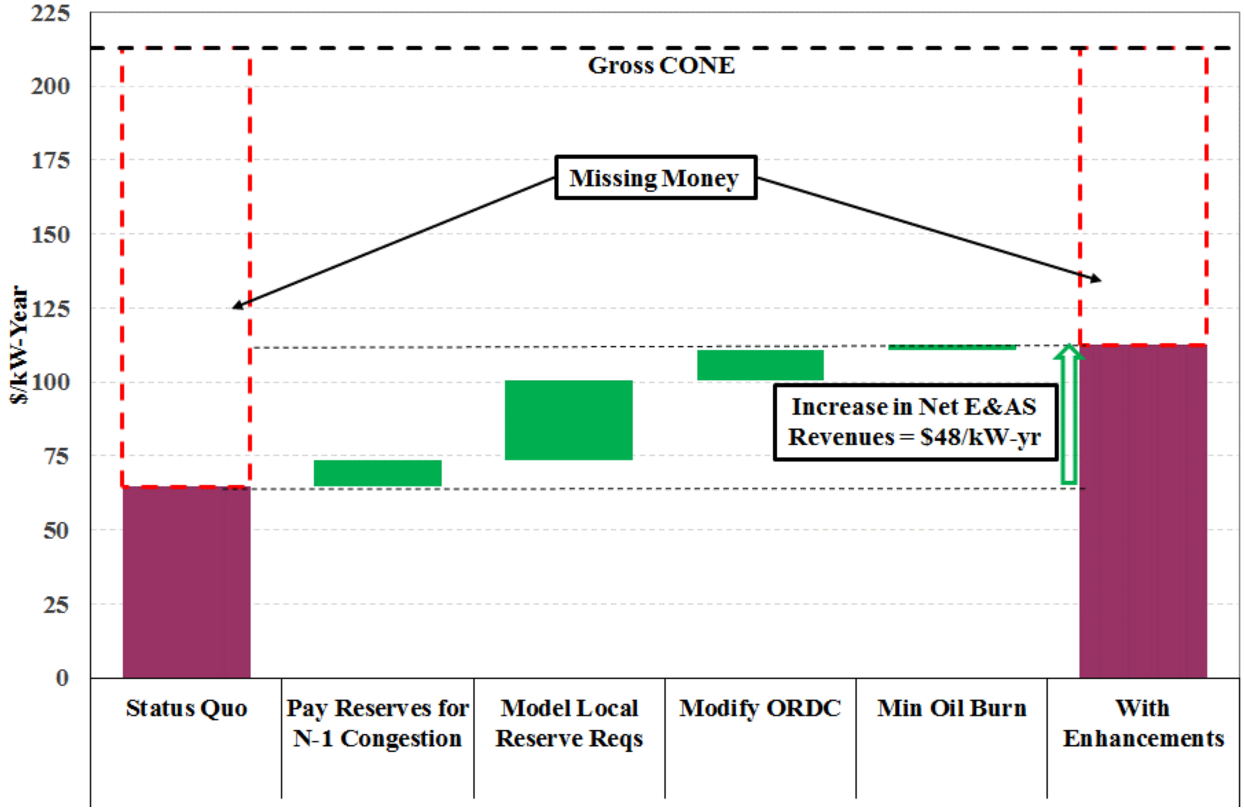


Figure A-113 to Figure A-116: Impacts of Real Time Pricing Enhancements on Net Revenues under As Found Conditions

Figure A-113 through Figure A-116 show the energy and capacity revenues for each resource type before (“Base”) and after the implementation of real time pricing enhancements (“wRecs”), in the following locations in New York City: a node that is representative of New York City prices, a node representative of the 345 kV system, and nodes in two load pockets. The figures also shows the shortfall in net revenues relative to the CONE/ GFC for each technology.

Figure A-113: Net Revenue Impact from Pricing Enhancements in New York City
2018

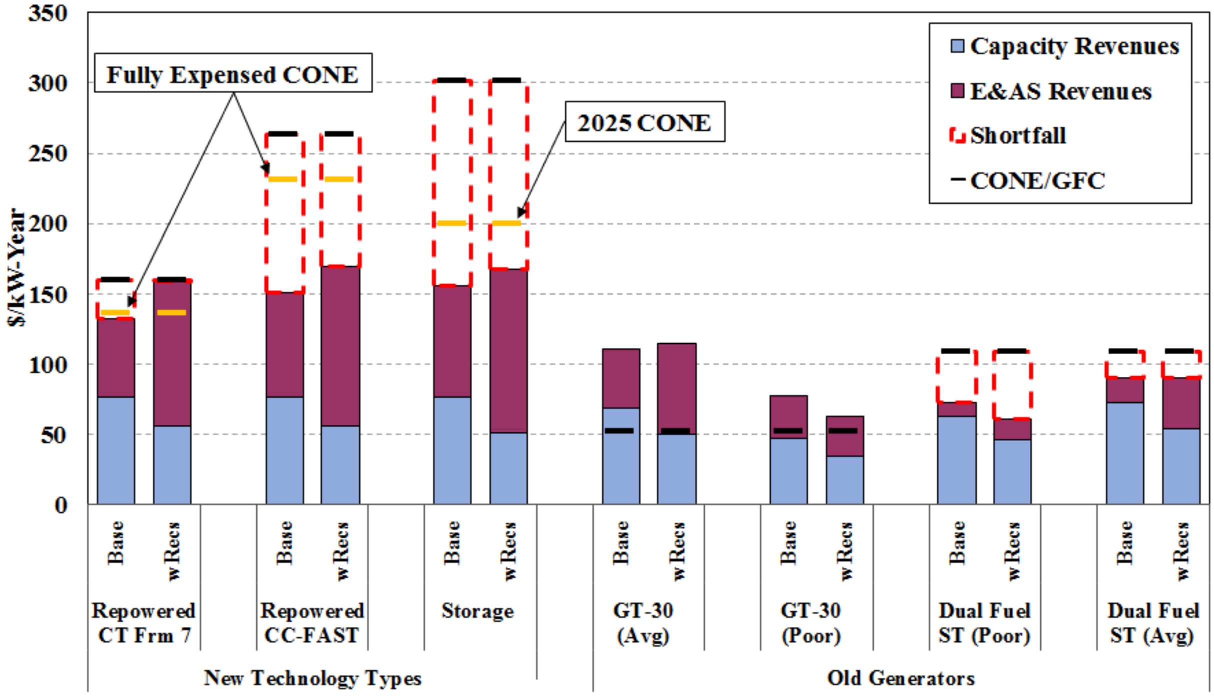


Figure A-114: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #1
2018

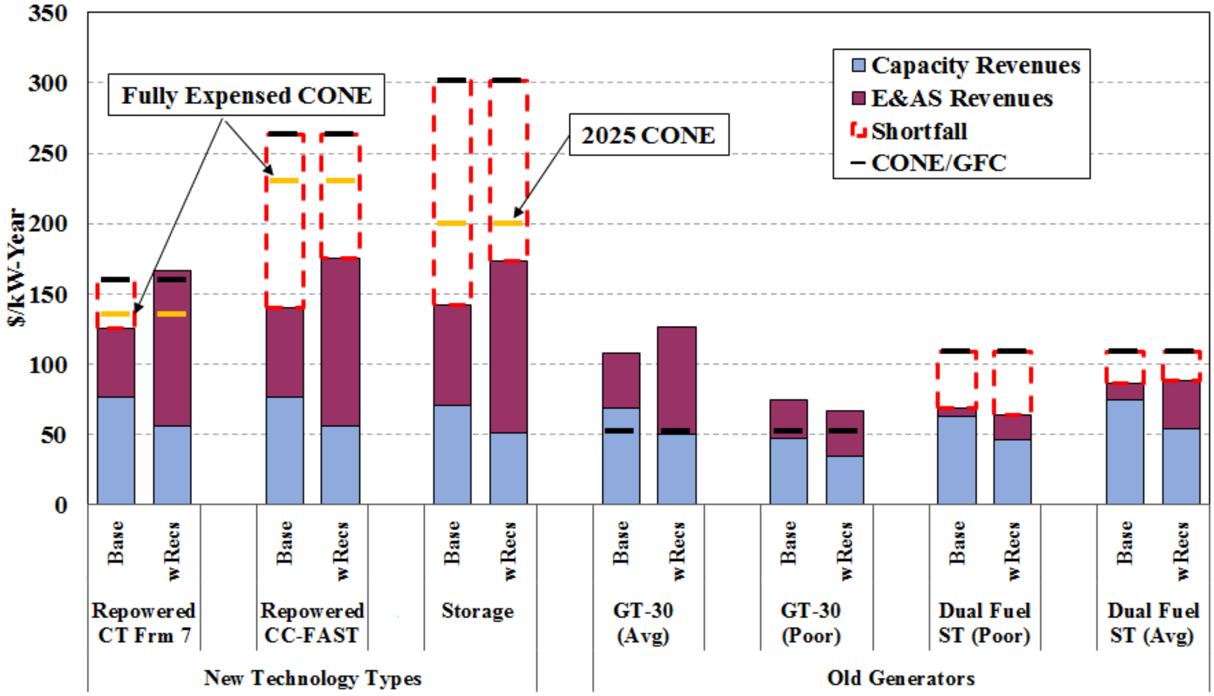


Figure A-115: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #2
2018

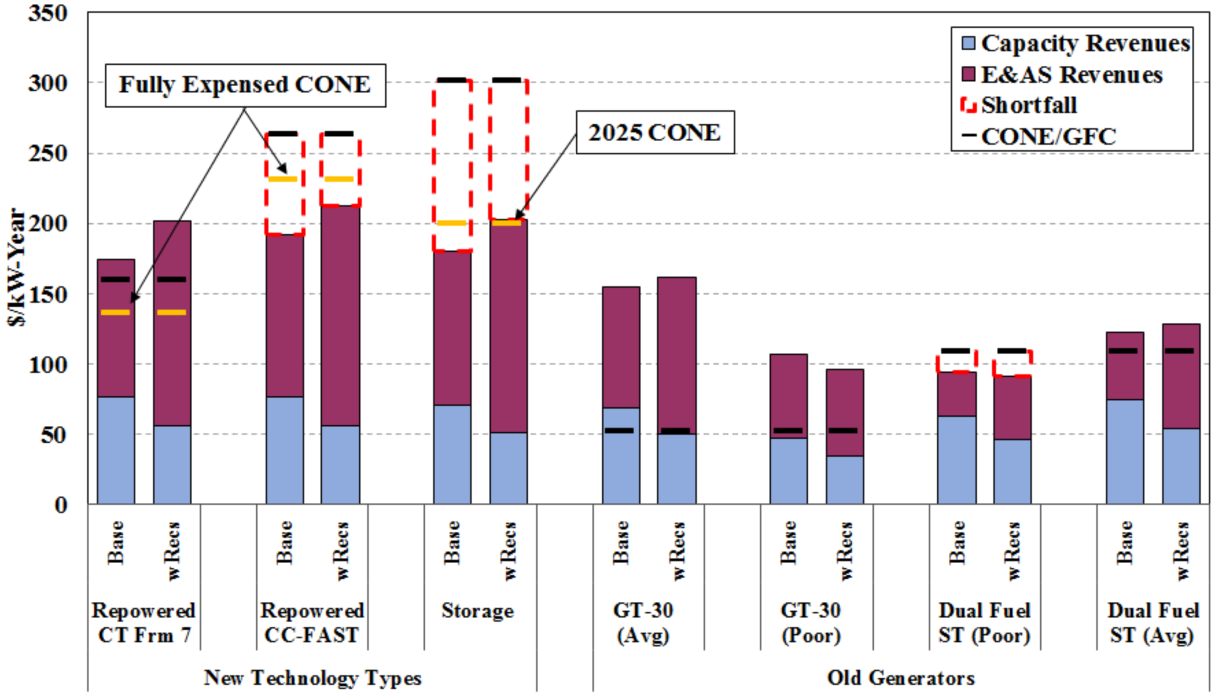
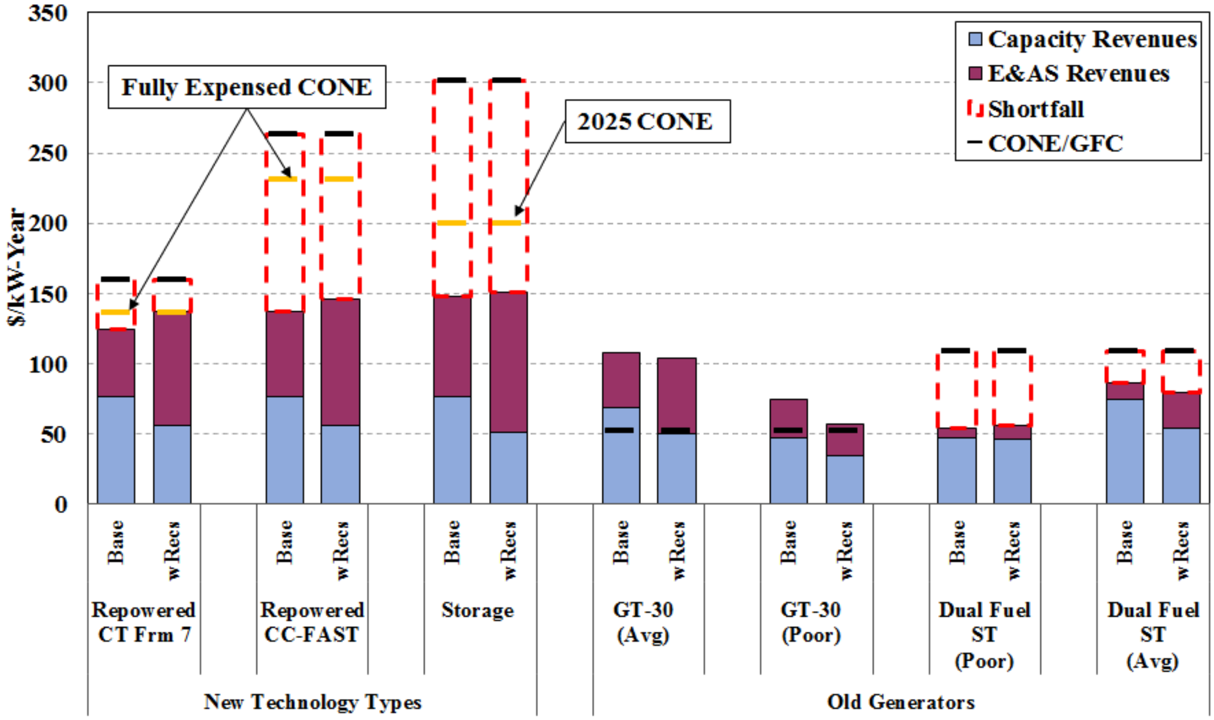


Figure A-116: Impact of Pricing Enhancements on Net Revenues – NYC 345 kV
2018



Key Observations: Impacts of Real Time Pricing Enhancements on Net Revenues

- *Impact on Capacity Prices* – The results indicate that the E&AS revenues of the Frame unit under long-term equilibrium conditions would increase by $48/kW-year as a result of implementing the pricing recommendations. This would reduce the Annual Reference Value (i.e. net CONE for the demand curve unit) by an equivalent amount, and would result in reduced capacity payments to all resources. For instance, at the level of surplus observed in 2018, the capacity prices would have been up to 35 percent lower because of the reduced capacity demand curve.
  - Of the recommendations that we considered for this analysis, modeling local reserve requirements in New York City load pockets (i.e. 2017-1) had the largest impact and accounted for 57 percent increase in the E&AS revenues for the demand curve unit.
- *Incentives for Resources at Representative New York City Node* – At the level of ICAP surplus observed in 2018, our simulations for resources at the representative New York City node indicate that energy market enhancements are likely to improve the net revenues of newer, more flexible units (Figure A-113). In contrast, the economics of older existing units are likely to become less attractive.
  - Under status quo conditions, the repowered Frame unit is unlikely to earn sufficient revenues to cover its Gross CONE. However, the results suggest that implementing the recommended changes is likely to increase the net revenues to a level that could result in profitable repowering of some existing units (particularly steam turbines).
  - A fast-start CC, given its low heat rate and ability to provide 10-minute non-spinning reserves, would benefit significantly (an increase of $40 per kW-year in its net E&AS revenues) due to pricing enhancements.
  - Increase in net revenues for storage is comparable to that of fast-start CC units. With their ability to derive significant revenues from energy and reserves as well as capacity markets, they are likely to see a large increase in net revenues. As a result, the increase in energy and reserve revenues of these units is greater than the drop in their capacity revenues.
  - As noted above, the economics of both of the older existing resources that we studied (GT-30 and ST) would be adversely impacted by the recommended enhancements to the real-time markets. Both types of older unit would receive lower capacity revenues, and lower total net revenues.[422]
    - For older GT-30 units, reserve revenues would drop if units were compensated in accordance with their performance as proposed in Recommendation 2016-2. GTs that perform worse than average would see a decrease in their total net revenues by an estimated $16 per kW-year.

[422] For poor performing GT-30 and ST units, we assumed an EFORd of 40 and 20 percent, respectively. For average performing GT-30 and ST units, we assumed an EFORd of 13 and 5 percent, respectively.

  - The net impact on ST units would be smaller than the impact on GTs because: a) these units benefit more than GTs from the Recommendation 2017-1, and b) there would be no performance-related reduction in E&AS revenues. As such, the net revenues of steam unit are unlikely to be sufficient to cover its GFCs under either scenario.

- *Incentives for Investment by Location* – The effects of the pricing enhancements on the energy and reserve prices vary significantly by location. Accordingly, as shown in Figure A-114 through Figure A-116, there is substantial variation in the changes in net revenues of each resource by location.
  - The results for Load Pocket #1 and #2 are heavily influenced by the large additional net energy and reserve revenues from implementing 2017-1. As a result, several resource types see a net increase (or in case of poor performers, less decrease) in their revenues when compared to other locations. In particular, the increase in net revenues of the Frame unit in Load Pocket #1 is likely to be sufficient to incent repowering in the scenario where the recommendations are implemented.
  - The nodes on the 345 kV system do not see a significant increase in energy or reserve prices from all the recommendations we considered. Hence, the increases in net revenues of all resources at this location are well below the increases in other locations. However, the results suggest that performance-based discounting of reserve revenues is likely to result in a below-average GT to be only marginally economic to continue its operations.

- The increased diversity in revenue mix by location is beneficial for the system. Energy and reserve markets model the electric system at a more granular level when compared to capacity markets, and hence more accurately value the benefits/ costs of placing resources in certain locations. As such, it is generally more efficient to compensate resources through the energy and reserve markets than through capacity markets.

XII. DEMAND RESPONSE PROGRAM

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 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.[423]
- 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.[424]
- 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.

Two additional programs 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. [425] 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.

423 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

424 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.

425 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, developing programs to facilitate participation by loads in the real-time market could be beneficial, although it is important that such a program provide efficient incentives to demand response resources.

This section evaluates: (a) reliability demand response programs, (b) economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions.

A. Reliability Demand Response Programs

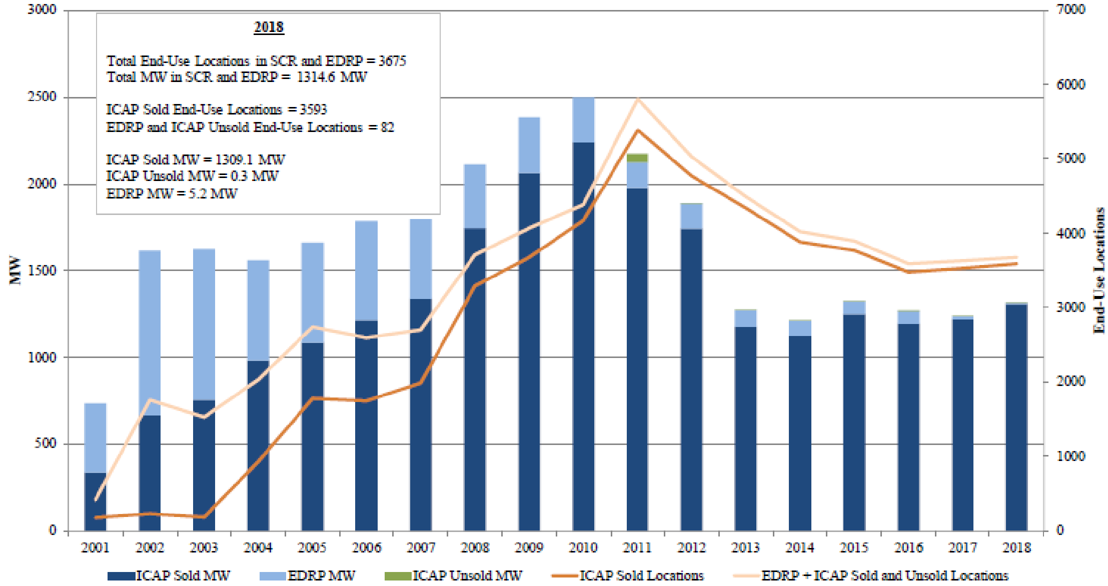
The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when the NYISO and/or a TO forecast a reliability issue.

Figure A-117: Registration in NYISO Demand Response Reliability Programs

Figure A-117 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2018 as reported in the NYISO's annual demand response report to FERC. The stacked bar chart plots enrolled 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.

Figure A-117: Registration in NYISO Demand Response Reliability Programs [426]

2001 – 2018



B. Economic Demand Response Programs

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 a bid floor price. 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.

The DSASP program was established in June 2008 to enable 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.

426 This figure is excerpted from the compliance filing report to FERC: *NYISO 2018 Annual Report on Demand Response Programs*, January 15, 2019.

The Mandatory Hourly Pricing ("MHP") 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. The MHP program is administered at the retail load level, so it is regulated under the New York Public Service Commission. 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.

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 actually lower prices. Prices can be well below $500/MWh after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time. NYISO currently has two market rules that improve the efficiency of real-time prices when demand response resources are deployed.

First, to minimize the price-effects of "out-of-merit" demand response resources, NYISO implemented the TDRP in 2007. This program is currently available in New York City, which enables the local Transmission Owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. Prior to July 2007, local Transmission Owners called all of the EDRP and SCR resources in a particular zone to address local issues on the distribution system. As a result, substantial quantities of demand response were deployed that provided no reliability benefit, depressed real-time prices, and increased 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 new 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.

Key Observations: Demand Response Programs

- In 2018, total registration in the EDRP and SCR programs included 3,675 end-use locations enrolled, providing a total of 1,315 MW of demand response capability.
  - SCR resources accounted for 99 percent the total enrolled MWs in the reliability-based program in 2018. This share has been increasing over time, reflecting that

many resources have switched from the EDRP program to the SCR program in order to earn revenue from the capacity market.

- In the Summer 2018 Capability Period, market-cleared SCRs contributed to resource adequacy by satisfying:
  - 5.6 percent of the UCAP requirement for New York City;
  - 4.2 percent of the UCAP requirement for the G-J Locality;
  - 1.9 percent of the UCAP requirement for Long Island; and
  - 3.9 percent of the UCAP requirement for NYCA.

- No resources have participated in the DADRP program 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.
- Three DSASP resources in Upstate New York actively participated in the market in 2018 as providers of operating reserves.
  - On average, the three resources collectively provided more than 100 MW of 10-minute spinning reserves in 2018, satisfying nearly 15 percent of the NYCA 10-minute spinning reserve requirement.
- In 2018, the NYISO activated reliability demand response resources on three days (i.e., July 2, August 28 and 29) in Zone J only, all for New York City reserve needs.
  - Various amounts of demand response were called additionally by local utility on the three days as well.
  - The performance of these DR calls is evaluated in greater detail in Section V.G of the Appendix.