NEW YORK INDEPENDENT SYSTEM OPERATOR
10 Krey Boulevard ♦ Rensselaer, NY 12144

March 23, 2016

By Electronic Filing

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Price Formation in Energy and Ancillary Service Markets Operated by Regional Transmission Organizations and Independent System Operators*; Docket No. AD14-14-000; Submission of Corrected Report**

Dear Ms. Bose:

In accordance with the Federal Energy Regulatory Commission's ("Commission's") November 20, 2015 Order Directing Reports ("Order") and consistent with the Commission's January 27, 2016 Notice of Extension of Time, on March 4, 2016 the New York Independent System Operator, Inc. ("NYISO") timely filed a Report in the above Docket. The NYISO has identified errors in the uplift and transparency sections of the Report it submitted on March 4 that are corrected in the Corrected Report that the NYISO has filed in conjunction with this letter.

The errors the NYISO identified and corrected are:

1. The table that appeared on page 45 of the Report indicated that Day-Ahead Margin Assurance Payments ("DAMAP") comprised approximately 2.5% of total uplift payments over the October 2014 to September 2015 period. However, that figure only addressed DAMAP that was specifically attributed to a NYISO or a Transmission Owner reliability request. DAMAP is also paid when circumstances change from Day-Ahead[1] to real-time and the NYISO's economic commitment process determines that the least-cost real-time market solution requires a Generator to buy-out of a portion of its Day-Ahead schedule, at a time when real-time prices are higher than Day-Ahead prices for the relevant product (Energy, Regulation or Operating Reserves). When this occurs, the NYISO pays a DAMAP to ensure the Generator is made whole and receives proper economic incentives to follow the NYISO's real-time dispatch instructions. When *all* causes of DAMAP are included, total DAMAP payments increase to approximately $9 million and DAMAP comprises approximately 10% of total NYISO uplift payments. This change also requires corresponding corrections to numbers and percentages that appear on pages 44, 45 (table), 47, 48 and 50 of the Report.[2]

[1] Capitalized terms that are not defined in this letter have the meaning assigned to them in the NYISO's Tariffs.
[2] Page numbering varies slightly between the original Report and the Corrected Report.

2. On page 46 of the Report the NYISO included an inaccurate statement that uplift resulting from actions taken in the Day-Ahead Market is borne by Day-Ahead load and transactions, and uplift arising in the Real-Time Market is borne by real-time load and transactions. A corrected statement appears on page 46 of the Corrected Report. It explains that actual, real-time Energy withdrawals (loads) are generally allocated uplift costs. There is a very small subset of uplift costs that are recovered from both virtual supply transactions and physical load. This uplift comes from additional commitments in the Day-Ahead Market to meet the NYISO's forecast load.

3. Finally, in the Transparency section of the Report the NYISO corrects the Out-of-Merit Generation ("OOM") entry that appears in the table on page 62 to explain that the NYISO publicly posts all Transmission Owner requested OOM reliability commitments and all NYISO OOM reliability commitments of generators that are not combustion turbines.

Please contact the undersigned with any questions regarding this letter or the accompanying Corrected Report.

Respectfully submitted,

/s/ *Alex M. Schnell*
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated at Rensselaer, NY this 23rd day of January 2016.

By: *\/s\/ John C. Cutting*

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators	))))	**Docket No. AD14-14-000**

CORRECTED REPORT OF
THE NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

In accordance with the Federal Energy Regulatory Commission's ("Commission's") November 20, 2015 Order Directing Reports ("Order") the New York Independent System Operator, Inc. ("NYISO") hereby submits this Corrected Report ("Report") responding to the Commission's questions. The NYISO shares the Commission's vision for proper price formation in the wholesale energy and ancillary services markets it administers. The NYISO continually reviews its markets to identify opportunities to improve long-term market efficiency by ensuring that market prices reflect, to the greatest extent practicable, the cost or value of each product.

I. COMMUNICATIONS AND CORRESPONDENCE

All communications and correspondence concerning this Report should be served as follows:

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II. REPORT IN RESPONSE TO COMMISSION QUESTIONS

The NYISO provides the following responses to the topics the Commission instructed it to address in this Report:

A. Pricing of Fast Start Resources

Commission Questions

1. Generally, the fast-start pricing logic consists of a dispatch run and a pricing run that relaxes the minimum operating limit of block-loaded fast-start resources such that these resources can set the LMP.

    a. Please explain during what period fast-start pricing logic is applied to block-loaded fast-start resources. For example, does fast-start pricing logic apply during a resource's initial commitment period or during its actual run time?
    b. Please explain the order in which the various fast-start pricing logic processes are executed. Specifically, are the dispatch run and pricing run executed separately or integrated into one process?
    c. Some RTOs/ISOs relax the minimum operating limit of a resource only in the pricing run, but some RTOs/ISOs currently also relax the minimum operating limit in the dispatch run. Does the fast-start pricing logic relax the minimum operating limit of a resource in the dispatch run, the pricing run, or both? Please explain why the RTO/ISO chose the specific approach.
    d. When a fast-start resource sets the LMP under the RTO's/ISO's fast-start pricing logic, how does the RTO/ISO ensure that the minimum operating limits of block-loaded fast-start resources are satisfied in dispatch?

NYISO Response

Block-loaded fast-start resources provide 10-minute and 30-minute non-synchronous reserves. These resources must either be (1) off, or (2) on and running at their upper operating limit (UOL) in order to provide energy. In other words, when a block-loaded resource is on, the minimum generation for the resource is equal to its UOL.

Day-Ahead commitments and hourly schedules are determined by the Security Constrained Unit Commitment (SCUC) to meet bid and forecasted load. Real-Time Commitment (RTC) software makes the commitment decision for resources in real-time every 15 minutes to meet forecasted load. Real-Time Dispatch (RTD) runs every 5-minutes and dispatches resources to meet actual and forecasted load, and sets prices.

Offline GT pricing and hybrid GT pricing are two methods used in RTD to set appropriate prices. These two approaches allow RTD to develop prices using actual generator costs to address constraints that only require a portion of a block-loaded unit's capability to solve.

Hybrid Pricing

In RTD, RTC and SCUC the cost of the next MW (while co-optimizing Energy, Operating Reserves, and Frequency Regulation) is used to establish the LBMP. The first ideal pass and second ideal pass are used to determine prices, while the physical pass, which follows the two ideal passes, is used to determine schedules in RTD. The physical pass does not utilize data output from the first and second ideal passes. The two ideal passes are required to accommodate the NYISO's hybrid GT pricing logic, while offline GT pricing is applied in all three passes. Final prices are established in the second ideal pass.

When block-loaded GTs are committed, dispatching these units to their maximum output, as their operational characteristics require, may displace more economic dispatchable units. The hybrid GT pricing logic allows online block-loaded units to be modeled as dispatchable to determine prices when their operation is needed to meet load, when the commitment displaces higher cost units, or to satisfy reserve requirements.

The physical pass determines the dispatch signal that is sent to all resources while respecting "physical" parameters, such as minimum generation MW, submitted to the ISO by Market Participants via their offers. For all committed GTs that are physically block-loaded, output is fixed at their upper operating limit within the physical pass. GTs only receive schedules from the physical pass, and do not receive any schedule produced by the first or second ideal passes.

The first ideal pass of hybrid GT pricing logic determines how each online block-loaded GT will be modeled in the second ideal pass of the hybrid GT pricing logic. Block loaded GTs that have been previously committed can be modeled as fully dispatchable from zero MW to the GT's UOL, or as block loaded at the GT's UOL.

Committed block-loaded GTs that are within their minimum run time are modeled as dispatchable from zero to their UOL in the first ideal pass. These GTs are eligible to set price in the second ideal pass if they are economic and dispatched to produce energy within the first ideal pass. Conversely, any committed block loaded GT that is within its minimum run time and is not economic during the first ideal pass is not eligible to set price in the second ideal pass. Committed block-loaded GTs that are outside of their minimum run time are always eligible to set price within the second ideal pass. This approach is reasonable because RTC will turn off such resources if they are not economic.

The second ideal pass is used to establish prices. Depending on the outcome of the first ideal pass, GTs will either be modeled as blocked loaded at the GT's UOL, or fully dispatchable from zero to the GT's UOL. If the GT is economically dispatched in the first ideal pass then the GT will be modeled as dispatchable in the second ideal pass from zero to the unit's UOL. Conversely, if such a GT is dispatched to zero during the first ideal pass, then the GT is blocked loaded at its UOL and is seen by the dispatch as a must-take resource which can never be marginal or set price.

Large differences between the physical dispatch schedules and ideal dispatch prices may introduce lost opportunities for more dispatchable resources when prices indicate that the dispatchable resource should be scheduled at a different output than results from the physical dispatch. This misalignment between prices and schedules can create unintended incentives for some dispatchable resources to stop following ISO dispatch instructions. The hybrid GT pricing logic avoids large differences between the schedules and prices produced from the physical pass and prices resulting from the second ideal pass by modeling some block loaded GTs as flexible, with prices from the second ideal pass being used for settlements. Modeling some block loaded GTs as flexible in the second ideal pass alleviates “lumpiness” in the resource supply curve by modeling select block loaded units as dispatchable when establishing prices. The NYISO’s hybrid approach arrives at a price signal more accurately representing the cost to meet load while reducing the lost opportunity of dispatchable resources.

Additionally, allowing block-loaded resources to be fully dispatchable to zero allows those resources to set the price whenever they were required to meet load. That is, anytime at least one megawatt of the resources output was necessary to meet load, the resource would be eligible to set the price. Limiting the range of dispatchability would tend to prevent these resources from setting price when only a small portion of their output was necessary to meet load. Because New York has load pockets where only block-loaded resources are available to meet the reliability needs, it is important to allow these resources to be eligible to set price anytime they are needed to meet load.

Offline GT Pricing

The NYISO utilizes the bids of offline 10-minute block-loaded GTs in RTD to set price on some occasions. Offline 10-minute block loaded GTs are modeled in both the physical pass and second ideal pass, but do not receive schedules for settlement from RTD. Start-up costs are considered for offline 10-minute GTs that are qualified to set price. The start-up cost of the uncommitted GT is divided by the GT's UOL and added to the energy offer of the GT to arrive at an adjusted energy offer. Offline block-loaded 10-minute reserve eligible resources are treated as dispatchable from zero to their Upper Operating Limit within each pass, with a zero MW/minute ramp down rate to reflect their minimum run time constraint within dispatch.[1] The zero MW/minute ramp down rate was developed because minimum run time constraints are only enforceable for online resources within the dispatch algorithm and it was important to have the dispatch of offline GTs represent, to the extent practicable, the GT's operating characteristics.

The NYISO first introduced the concept of allowing offline 10-minute GTs to set price as a way to establish more efficient pricing in constrained load pockets. The NYISO has found that allowing these GTs to set price provides both the market and the NYISO operators an indication that an offline GT would efficiently solve the reliability need and, therefore, its start-up is warranted. The offline GT pricing capability is especially useful for adding price transparency to unanticipated changes between the time that RTC has completed its commitment evaluation and the 5-minute RTD dispatch evalution when offline 10-minute GTs are the only option for solving a reliability need. Because offline 10-minute GTs are capable of starting within 10 minutes, prior to a subsequent RTC execution, they are eligible to set price in RTD.

[1] Such units are excluded from commitment when they are within their minimum down time.

Offline GTs that are not eligible to provide 10-minute non-synchronous reserve are not eligible to set price in RTD. Instead, the NYISO relies on RTC, with its look-ahead capability, to commit offline GTs with start-up times that are longer than 10 minutes. Once committed, these resources are subjected to the hybrid GT pricing logic within RTD.

Commission Question

1. Generally, the fast-start pricing logic consists of a dispatch run and a pricing run that relaxes the minimum operating limit of block-loaded fast-start resources such that these resources can set the LMP.

    e. CAISO, ISO-NE, NYISO, and MISO currently relax the minimum operating limit of eligible block-loaded fast-start resources to zero, while PJM relaxes the minimum operating limit by 10 percent. Please explain the reasons for the specific approach used to relax minimum operating limits. For SPP, please explain whether minimum operating limits are relaxed to zero or not, and the reasons for the chosen approach.

NYISO Response

The NYISO relaxes the minimum operating limit of block-loaded resources to zero when applying its hybrid GT pricing logic. This is done so that the algorithm can distinguish between units that are constrained by the block loading treatment and those that are not. In New York, there are constrained load pockets where GTs are the only resource that can set the price. It is important to allow maximum dispatch flexibility for the pricing algorithm to set efficient prices in these areas.

Commission Question

2. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, related to fast-start pricing logic and why those changes are being pursued. What tradeoffs, in terms of costs and benefits, are the RTO/ISO and/or stakeholders considering during this process? Please provide a qualitative discussion of whether and how enhancements to existing fast-start pricing logic could potentially reduce overall uplift.

NYISO Response

In 2016 the NYISO will be working with its stakeholders on the "Hybrid GT Pricing Improvements" project. This project is based on recommendation 10 in the Market Monitoring Unit's (MMU's) 2014 State of the Market Report.[2] The MMU observed that in 7 to 12 percent of intervals there are block-loaded units that are economic but are not qualified to set price. This outcome has been attributed to the Hybrid GT methodology where multiple block loaded GTs have been committed and not all are found to be eligible to set price. Some GTs are eligible to set price, while others are not, due to system changes between when RTC evaluated the fleet and when RTD is dispatching the fleet. The 2016 project will evaluate the proposal to allow all block-loaded units that are economically committed by RTC to be qualified to set price in the final pricing pass. The project will also evaluate amortizing GT start up costs into their offer over the initial phase of the GT's commitment and allowing these costs to be reflected in prices. The proposed modification is intended to increase the accuracy of price signals, avoid intervals where the LBMP is lower than the bid cost of the GT, and to reduce uplift.

[2] The MMU also raised this concern in earlier State of the Market Reports.

Commission Question

3. Please explain the following regarding the RTO's/ISO's fast-start pricing logic eligibility:

    a. What type of resource (e.g., combustion turbine) may be considered a fast-start resource and what are the eligibility requirements (e.g., start-up time and/or notification time)? Are resources other than block-loaded fast-start resources eligible to set the LMP under the fast-start pricing logic? Can a fast-start resource choose not to be included in the fast-start pricing logic?

NYISO Response

What type of resource (e.g., combustion turbine) may be considered a fast-start resource and what are the eligibility requirements (e.g., start-up time and/or notification time)?

All committed block-loaded resources qualified to provide 10-minute nonsynchronous reserves are considered in the NYISO's hybrid GT pricing logic. Certain Out of Merit Generation (OOM) types disqualify resources from setting price. These include OOMs due to Transmission Owner (TO) reliability, generator requests, ISO security, ISO voltage support, TO voltage support and for testing.

All 10-minute non-synchronous block loaded resource that are offline are included in the NYISO's offline pricing logic.

Are resources other than block-loaded fast-start resources eligible to set the LMP under the fast-start pricing logic?

Committed dispatchable resources are considered in the supply curve when establishing prices and schedules; the bids of such resources can set prices. These resources are not directly considered by the hybrid GT pricing logic or offline GT pricing.

Can a fast-start resource choose not to be included in the fast-start pricing logic?

All block-loaded resources eligible to provide 10-minute non-synchronous and 30-minute reserves are included in the NYISO's hybrid GT pricing logic. All 10-minute non-synchronous reserve eligible resources are considered in the NYISO's offline GT pricing. Fast-start resources cannot choose to be included or excluded from the pricing logic.

Commission Question

3. Please explain the following regarding the RTO's/ISO's fast-start pricing logic eligibility:

    b. Can commitment-related start-up and/or no-load costs be accounted for in the LMP? If so, please explain how and provide numerical examples to illustrate how these costs are included in LMP.

NYISO Response

Start-up and no-load commitment costs are not accounted for in the LBMP unless offline GTs are used to set the price. This is because dispatched units' start-up and/or no-load costs have already been evaluated in the commitment passes, the commitment was determined to minimize production cost, and as a result LBMPs are largely high enough to cover these commitment costs. Start-up costs are considered for offline 10-minute GTs that are qualified to set price and these costs are amortized over the GT's UOL and added to the GT's energy offer as further explained in the NYISO's response to Pricing of Fast Start Resources question 3(c).

Commission Question

3. Please explain the following regarding the RTO's/ISO's fast-start pricing logic eligibility:

    c. Can offline block-loaded fast-start resources set the LMP? If so, please explain how and provide numerical examples to illustrate how such resources set the LMP.

NYISO Response

Offline 10-minute eligible resources are qualified to set price in the pricing pass. The minimum output levels of such resources are relaxed to zero. In other words, they are considered dispatchable and are allowed to set the price if they are economic. The start-up costs of each such resource, divided by the generator's upper operating limit, is added to the energy offer costs. Combining start-up costs with energy offer costs when allowing offline GTs to set price ensures that the stated LBMPs cover the GT's approximate commitment costs. Unlike GTs that have been committed and have an enforced minimum run time over which commitment costs can be recovered, offline GTs do not have an enforced minimum run time. Therefore the LBMP must immediately account for the commitment costs.

Numerical Example:

Consider the following units and a 475 MW load:

Status	Resource	Energy Offer Price ($/MWh)	Min Gen	UOL	Start Up Cost ($)
NOT COMMITTED	GT	75	50	50	1000
COMMITTED	Flexible Unit1	60	25	300	n/a (already online)
COMMITTED	Flexible Unit2	30	25	100	n/a (already online)
COMMITTED	Flexible Unit3	25	5	50	n/a (already online)

Physical Pass:

The physical and pricing passes each take place within RTD. Offline GTs are modeled as dispatchable within the physical pass *i.e.*, their minimum generation level is set to zero. Offline GTs are not provided a schedule unless committed by the operator. This treatment allows RTD to price the need for GTs due to changing conditions that were not seen in RTC, while allowing NYISO Operations to confirm that the condition is expected to continue and is not due to a transient issue before committing the generator. As explained above, the start-up cost of the uncommitted GT is divided by the unit's UOL and added to the energy offer of the unit to arrive at an adjusted energy offer. The NYISO utilizes Regulation Service to compensate for any under generation.

Status	Resource	Adjusted Energy Offer ($/MWh)	Min Gen	UOL	Physical Dispatch (MW)
NOT COMMITTED	GT	95	0	50	25
COMMITTED	Flexible Unit1	60	25	300	300
COMMITTED	Flexible Unit2	30	25	100	100
COMMITTED	Flexible Unit3	25	5	50	50

Pricing Pass:

The adjusted energy offer of the uncommitted resource is also considered in the pricing pass. The uncommitted 10-minute non-synchronous eligible GT is modeled as dispatchable within the pricing pass. Again, the GT is not provided a schedule unless it is committed by the operator.

Status	Resource	Adjusted Energy Offer ($/MWh)	Min Gen	UOL	Start Up Cost ($)	Pricing Dispatch Solution (MW)
NOT COMMITTED	GT	95	0	50	1000	25
COMMITTED	Flexible Unit1	60	25	300	n/a (already online)	300
COMMITTED	Flexible Unit2	30	25	100	n/a (already online)	100
COMMITTED	Flexible Unit3	25	5	50	n/a (already online)	50

Because the uncommitted GT in the above example is dispatched to serve the 475 MW load, the GT would set the Energy component of the LBMP at $75/MWh + ($1000/50MW) = $95/MWh in the pricing pass.

Commission Question

4. Based on the definition in the RTO/ISO tariff, how much block-loaded fast-start capacity (in MWs) is available? How much fast-start capacity is not block-loaded? Please provide as seasonal capability (i.e., summer capability) and include only capacity that is currently in service and can participate in the market.

NYISO Response

Section 1.6 of the NYISO OATT defines a Fixed Block Unit (*i.e.* a block-loaded unit) as "[a] unit that, due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level."

The combined upper operating limits of all block-loaded, fast-start, 10-minute eligible units currently in service and participating in the NYISO markets as of February 26, 2016 is approximately 2,000 MW. The summed upper operating limits of dispatchable, 10-minute eligible, fast-start capacity units currently in service and participating in the NYISO markets as of February 26, 2016 is between 1500 MW and 2000 MW.[3] The summed upper operating limits of block-loaded, 30-minute eligible, fast-start unit currently in service and participating in the NYISO markets as of February 26, 2016 is approximately 3,000 MW. The aforementioned figures do not vary significantly when considering summer vs. winter capability.

Commission Question

5. As previously discussed, fast-start pricing logic can result in over-generation or in resources not following dispatch instructions.

    a. Please discuss the extent to which fast-start pricing logic has resulted in over-generation or resources otherwise not following dispatch instructions.
    b. Please describe the current approach, if any, used to address over-generation or the incentive to not follow dispatch instructions, and discuss the benefits to this approach versus other potential approaches to address this problem. For example, approaches include paying resources their opportunity costs, or penalizing them for deviating from dispatch instructions.

NYISO Response

The NYISO's generation fleet responds well to NYISO-issued base points and instructions. The NYISO has not identified its fast-start pricing logic as causing systemic over-generation, or providing incentives for resources to not follow NYISO dispatch instructions.

The NYISO believes that a combination of well-designed market rules incent resources to follow dispatch instruction and prevent unscheduled overproduction. First, resources changing their bid type from ISO-committed in the Day-Ahead Market to self-committed in the Real-Time Market give up their eligibility to receive Bid Production Cost Guarantee (BPCG) payments in the Real-Time Market. Dispatchable resources are unlikely to risk losing guarantee payments

[3] The NYISO uses a range to ensure that its public response does not reveal any Confidential Information.

(that are paid over the dispatch day) to garner additional profits over the relatively brief and unpredictable period when their production is displaced by a block-loaded resource. Second, a generator producing above its basepoint is only compensated for overproduction that exceeds the basepoint by 3% of the generator's UOL, or less.

<u>Commission Question</u>

6. For those RTOs/ISOs that apply fast-start pricing logic only to the real-time market, please explain why this methodology is not applied to the day-ahead market.

<u>NYISO Response</u>

The NYISO's hybrid GT pricing logic is not applied by SCUC or by RTC because all GTs are modeled as dispatchable in the pricing passes of both SCUC and RTC. SCUC and RTC can fully evaluate when the units are marginal and thus qualified to set prices, while also determining the least cost set of resources to serve load. RTD does not commit resources, and is unable to determine marginality of offline block-loaded units without the hybrid GT pricing logic.

<u>Commission Question</u>

7. Certain RTOs/ISOs argue that expanding the fast-start pricing logic to resources other than block-loaded fast-start resources is not needed. However, this limits the amount of fast-start resources that are able to set LMP. Please explain the advantages or disadvantages of allowing fast-start resources that are not block-loaded but that have a limited operating range to set the LMP, and please explain whether it is appropriate to allow the commitment-related start-up and no-load costs of such resources to affect prices.

NYISO Response

The NYISO only applies hybrid GT pricing logic and offline GT pricing logic to block-loaded fast-start resources. There has been no discussion of allowing dispatchable units to set price because dispatchable fast-start resources are able to set price within their dispatchable range when they are committed. Dispatchable fast-start resources are not common in New York and the few that exist are not situated in constrained load pockets. The expected benefit of implementing hybrid pricing for these resources is minimal.

B. Commitments to Manage Multiple Contingencies

The NYISO's SCUC, RTC and RTD secure the transmission system to address single contingency events. A subset of these single contingency events involve the simultaneous outage of multiple transmission elements. For example, failure of a circuit breaker due to a fault-to-ground may be cleared from the system by the operation of multiple circuit breakers, resulting in the outage of multiple transmission system elements.[4] The NYISO does not ordinarily perform its market evaluations in a manner that would identify the incremental resource commitments for single contingencies that involve multiple transmission elements.

New York State Reliability Council (NYSRC) reliability rules stipulate that Con Edison "…operate certain areas of the New York State (NYS) Bulk Power System to meet more stringent local reliability requirements than the rest of the NYS Bulk Power System."[5] The NYISO accommodates the Con Edison requirements in performing market analysis for resource

[4] Paragraph 30 and footnote 61 of the Order describe this example as an N-2 event.

[5] Link to NYSRC Reliability Rules:
http://www.nysrc.org/pdf/Reliability%20Rules%20Manuals/RRC%20Manual%20V35%20Final%208-14-15.pdf

commitment and scheduling for both Day-Ahead and Real-Time markets. For example, in performing its Day-Ahead Market evaluations the NYISO includes a set of constraints, including multiple contingency events, that may be satisfied by combinations of various New York City (NYC) zone J generator commitments which satisfy the NYC Local Reliability Requirements (LRR). The Power Supplier uplift associated with the incremental resources committed to satisfy the LRR is calculated and the costs are allocated to Load Serving Entities in the NYC zone.

In performing its Real-Time Market evaluations while a Con Edison Storm Watch is in effect, the NYISO includes a set of N-1-1 contingencies involving Con Edison transmission equipment in zones outside of NYC. The NYISO employs a calculation, described in Appendix M of its Accounting and Billing Manual,[6] which identifies the incremental costs associated with securing the transmission system for the Con Edison Storm Watch condition. The NYISO allocates these Storm Watch costs to NYC zone Load Serving Entities.

Commission Question

1. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, to incorporate the costs of multiple contingencies into clearing prices for energy and ancillary services. This description should include estimated costs and a timeline for implementation.

[6] Link to Accounting and Billing Manual: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Administrative/acctbillmnl.pdf

NYISO Response

As described above, the NYISO currently solves single contingency events that may include the simultaneous outage of multiple transmission elements. The clearing prices for energy and ancillary services incorporate the costs of securing the system for these events.

The costs of solving certain multiple contingency events are addressed through the markets in three primary ways. First, the multiple contingency Con Edison Storm Watch criteria is secured for explicitly in the Real-Time Market and reflected in clearing prices.

Second, as it relates to the Con Edison LRR criteria that are solved for in the Day-Ahead Market, the solution will include the commitments needed to satisfy the LRR criteria. The resources required to meet the LRR criteria are eligible to set price. The Con Edison LRR criteria are not otherwise explicitly reflected in the Day-Ahead Market clearing prices. However, if the Con Edison LRR criteria were considered after the Day-Ahead Market posted, subsequent resource commitments would sometimes be required, and would result in an over commitment of resources transitioning into real-time. The NYISO's approach develops efficient commitments and schedules.

Third, as further explained in response to the next question, certain reserve products are used to prepare for multiple contingencies across the New York Control Area (NYCA). Given that the NYISO's market solution is a co-optimization between energy, operating reserves and regulation with the objective of minimizing total production cost, the cost of solving for multiple contingencies through reserves is already included in the clearing prices. The calculation of clearing prices for each of these products incorporates resource lost opportunity cost, fairly compensating resources for each product in the majority of intervals.

No projects that are currently being considered propose to incorporate the costs of additional multiple contingency constraints into the market solution. The NYISO and its stakeholders are, however, considering a project called "Modeling 100+kV Transmission Constraints," which is based on a recommendation in the 2014 State of the Market report produced by the NYISO's Market Monitoring Unit. The proposed project would assess the value and impacts of modeling 115/138kV transmission constraints in the Day-Ahead and Real-Time Markets.

Modeling constraints on facilities above 100 kV that are not modeled today would be expected to reduce out-of-market commitments to resolve Western transmission constraints. Market incentives for investment in resources on the 115kV system in upstate New York may be improved by reflecting these facilities in the NYISO's energy and ancillary services markets.

Commission Question

2. Please explain whether constraints or reserve products are used to address multiple contingencies in the day-ahead and real-time energy and ancillary services markets and, if so, how such constraints or reserve products are incorporated in market models. Specifically, describe (1) the criteria for determining what constraints or reserve products are included in the day-ahead or real-time market model to address multiple contingencies, and (2) provide a detailed description of how constraints or reserve products to address multiple contingencies are included in both the day-ahead and real-time market model.

NYISO Response

Operating reserve constraints are modeled in the Day-Ahead and Real-Time Markets. Operating reserve constraints are addressed by imposing locational and physical resource qualifications for providing each type of reserve. The amount of a particular operating reserve product the NYISO secures its system to depends on rules established by the North America

Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC). The NERC, NPCC and NYSRC rules are used to establish the locational MW requirements for operating reserve procured by the NYISO in the Day-Ahead and Real-Time Markets.[7] Not all locational reserve requirements are in place to secure against multiple contingencies.

Three locational operating reserve product constraints modeled are specific to multiple contingencies. These include the Southeastern New York (SENY) 30-minute reserve requirement, the East of Central East (EAST) 10-minute non-synchronous reserve requirement, and the New York Control Area (NYCA) 30-minute total reserve requirement. Specifically, 1300 MW of 30-minute total reserve is procured in the SENY reserve region in order to re-prepare the system to withstand the next worst contingency following the occurrence of the worst contingency for the UPNY-SENY interface. Twelve hundred MW of 10-minute non-synchronous reserve is procured in the EAST reserve region to restore flows on the Central East internal interface to within limits following the worst contingency, in order to prepare the system to suffer the next worst contingency. The NYCA 2620 MW 30-minute total reserve requirement, tied to an NYSRC rule, is intended to prepare the system to suffer the worst two supply contingencies before load shedding is required. NYSRC rules also include single contingencies that involve multiple elements, which are included as constraints within the NYISO's Day Ahead and Real-Time Markets.

A Day-Ahead Reliability Unit (DARU) may be committed at the request of a Transmission Owner (TO), or by the NYISO to address local or statewide reliability needs.

[7] NYISO posting of locational requirements: http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

DARU commitments are included with the Day-Ahead Market run, providing for a more efficient commitment relative to if the unit were committed after the establishment of Day-Ahead schedules. All requests by TOs to commit generators via the DARU process, as well as NYISO-initiated DARUs, are posted to the OASIS at or before the time of the Day-Ahead Market close. DARU requests may or may not be to address multiple contingencies. Typically, the TO will provide the ARR that triggers the DARU commitment.

Local Reliability Rules (LRR) defined by the NYSRC are included in the Day-Ahead and Real-Time Markets. Five LRRs are included in the NYISO's markets. They address locational reserves, unit commitment, potential loss of generator gas supply, and Storm Watch in New York City (NYC), as well as potential loss of generator gas supply on Long Island.

The NYISO includes in its Day-Ahead Market evaluation the NYC zone generator commitment combinations which Con Edison identifies as necessary to satisfy NYSRC requirements. The NYC LRR contingencies are evaluated and may affect resource commitments in each Day-Ahead Market evaluation.

Each NYC LRR requirement is presented as minimum generation requirement to be satisfied by a subset of the NYC generation resources. There are multiple requirements for various localities within the NYC zone to secure for thermal, voltage, loss of natural gas and emissions conditions. Some required minimum generation production values may vary as a function of demand. NYC generation resources may contribute to satisfying multiple LRR requirements.

The NYISO includes in its Real-Time Market evaluation the N-1-1 contingencies Con Edison identifies as satisfying NYSRC real-time operational requirements. Storm Watch contingencies occur in real-time and require RTC and RTD to secure one or a number of multiple contingencies cases as outlined in the table A.5 of the NYISO Emergency Operations Manual.[8] Storm Watch contingencies are included in Real-Time Market evaluations for the period over which Con Edison invokes the procedure. These periods may be non-contiguous within a day and may span multiple days.

Commission Question

3. If resources are manually committed (i.e., committed outside of security constrained unit commitment processes) to address multiple contingencies, please describe the criteria used to determine whether a manual commitment will be made and how the RTO/ISO determines what resources are committed. If resources are manually committed to address only some subset of multiple contingencies, please describe what criteria the RTO/ISO uses to determine whether a manual commitment will be made.

NYISO Response

The NYISO's SCUC and RTC can commit resources to address multiple contingencies, as described in the NYISO's response to Commitments to Manage Multiple Contingencies question 2. The NYISO and Transmission Owners can also manually identify resources that must be committed to meet reliability criteria in advance of the Day-Ahead Market by issuing a DARU designation. Should the need arise to commit additional resources outside of the market process in order to resolve reliability requirements, the NYISO determines which resources are available within the needed timeframe to solve the necessary constraints and commits the most economic resource or resources from the options available to it.

Resources may be manually committed using a Supplemental Resource Evaluation (SRE) when a need arises. An additional type of manual commitment is Out-of-Merit Generation

[8] Link to Emergency Operations Manual: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/em_op_mnl.pdf

(OOM). An OOM commitment or dispatch can be implemented to secure the bulk power system, during communication failures, or when the Real-Time Commitment does not successfully run. Transmission Owners can request that a generator be committed or dispatched OOM for local reliability. Generators that are experiencing operating difficulties can request an OOM through their local Transmission Owner.

Commission Question

4. For each month during the twelve month period between October 1, 2014 and September 30, 2015, please provide: (1) an estimate of the number of resource commitments made in real-time or day-ahead to address multiple contingencies. This estimate should be broken down by geographic area (e.g., reserve zone or load zone), if possible; and (2) an estimate of the dollar amount of uplift paid to resources committed to address multiple contingencies.

NYISO Response

The NYISO performs a co-optimized dispatch of resources to provide energy, regulation, and reserves to address all system needs incorporating all of the criteria described in response to the prior questions. As such, it is not possible to tie specific resource commitments to a specific set of multiple contingency constraints that are secured in the market software. The cost of a resource committed to resolve one requirement in the model (*e.g*. a locational operating reserve requirement), may have resulted from the unavailability of another resource that was scheduled to provide a product of greater value (*e.g*. energy). The multiple contingency commitments that are capable of being distinguished are set forth in the table below.

Transmission Owners are required to provide a reason, including any applicable ARR codes, for DARUs and the NYISO posts the ARR codes that are provided with its Operational

Announcement website posting.[9] The NYISO also reports commitments with ARR designations as part of its Operations Performance Metrics Monthly Report.[10]

The table set forth below identifies the resource commitments and Power Supplier uplift paid for the securing the New York City Local Reliability Rules. It also identifies the number of hours for which Con Edison implemented its Storm Watch Procedure and the storm watch costs allocated to the NYC zone Load Serving Entities.[11] For more information on LRR commitments, please see the NYISO's response to question 2 under the topic heading "Commitments to Manage Multiple Contingencies."

Month	NYC LLR commitment unit-hrs	Unique NYC LRR Units	NYC LLR DAM BPCG $	Storm Watch Procedure Hours	Storm Watch Procedure BMCR $
10/2014	253	4	$165,244.20	0	$0.00
11/2014	144	3	$226,885.40	0	$0.00
12/2014	28	4	$57,975.68	0	$0.00
01/2015	164	6	$849,959.29	0	$0.00
02/2015	96	2	$412,982.43	0	$0.00
03/2015	239	2	$281,228.70	10	$0.00
04/2015	648	2	$636,567.96	0	$0.00
05/2015	1326	3	$1,754,951.63	21	$723,021.91
06/2015	1197	6	$1,649,918.76	27	$2,334,798.49
07/2015	743	5	$594,603.90	19	$374,013.76
08/2015	842	6	$1,033,885.10	7	$354,525.34
09/2015	521	2	$448,454.94	1	$60,637.43
			$8,112,657.99		$3,846,996.93

[9] The NYISO's operational announcements can be found on its website: http://www.nyiso.com/public/markets_operations/market_data/reports_info/index.jsp The user must select the Operational Announcements checkbox to see the reports.

[10] The Operations Performance Metrics Monthly Report is located in the Monthly Reports folder at the following link: http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp

[11] Though BMCR is not a form of uplift, it is included in the table for completeness.

Commission Question

5. Describe whether and how incorporating additional multiple contingency constraints or using reserve products in day-ahead or real-time market models would improve price formation. If taking additional steps to incorporate multiple contingency constraints or using reserve zones in day-ahead or real-time market models is unnecessary, impracticable, or would negatively affect price formation, please explain why.

NYISO Response

The NYISO finds it effective to solve for single contingency events resulting in the outage of multiple transmission elements through the market.

The NYISO has found locational reserve regions to be an effective means of managing multiple contingencies. When managing multiple contingencies there is often a limited period of time for the NYISO's operators to restore the system to normal operating conditions following the occurrence of the "first" contingency. This time element can best be modeled in current market platforms using a locational reserve requirement.

Alternatively, the multiple contingencies can be modeled directly as the simultaneous loss of several transmission or generation elements. This modeling method has costly side effects. The modeling must immediately account for reduction in transmission capability which results in inefficient use of the transmission system and result in higher total production costs due to the dispatch of less efficient generation. This effectively requires the ISO or RTO to maintain costly transmission level "reserves" by holding back usable transmission and generation ramp capability in order to be able to immediately react to the multiple contingency event, should it occur.

By securing for multiple contingencies in its market evaluations the NYISO provides power suppliers with commitment and dispatch instructions relating to these conditions in the same manner as securing for the single event contingencies; there is no out-of-the-ordinary communication required.

The effect of securing the N-1-1 contingencies is transparent in that the NYC LLR commitment type for each commitment is posted, and the cost allocation to the NYC zone Load Servicing Entities separately identifies costs that are attributable to the NYC LRR, and costs that are attributable to the Con Edison Storm Watch procedures. The costs of, and other information concerning the NYC LRR commitments and Storm Watch are included in various reports that the NYISO regularly publishes.[12]

Power suppliers are able to recover their costs through the combination of LBMP revenue, Bid Production Cost Guarantee (BPCG) payments and Day-Ahead Margin Assurance Payments (DAMAP). Constraints involving the NYC LRR may affect resource commitment, but these constraints are not priced and so will not directly affect LBMPs. Storm Watch contingencies are priced and affect the real-time LBMP. The constraints that are activated to address a Con Edison Storm Watch are included in Real-Time Market evaluations when Storm Watch conditions exist in the monitored geography. Con Edison operations invokes Storm Watch and provides advance notice to the NYISO when possible so that the NYISO may include these contingencies in its look-ahead Real-Time Market evaluation.

The practices the NYISO employs to secure multiple contingency constraints supports the Commission's price formation goals. They provide correct incentives for Market Participants to follow dispatch signals, provide price transparency, and provide the opportunity for suppliers to recover their costs. As explained above, the NYISO secures for several different

[12] See the NYISO's response to Transparency questions 1 and 2 for information on the reports the NYISO publishes.

types of multiple contingency constraints within its market evaluations, minimizing the need for out-of-market resource commitments.

C. Look-Ahead Modeling

Commission Question

1. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, related to look-ahead modeling. For any look-ahead modeling enhancements that the RTO/ISO and/or its stakeholders are currently considering, please discuss any evaluation of the costs and/or complexities of look-ahead modeling relative to its potential benefits, and the estimated time frame for implementation of any look-ahead modeling enhancements.

NYISO Response

The NYISO incorporated look-ahead modeling into its Day Ahead Market at its inception in 1999 and incorporated look-ahead modeling into its Real Time Market in 2005. Post 2005 the NYISO has implemented various look-ahead modeling enhancements.

The NYISO regularly assesses if additional refinements are needed and has included a "RTC-RTD Forward Horizon Coordination Improvements" market design project for 2016. Slight modeling inconsistencies between RTC and RTD look-ahead evaluations can arise as the programs evaluate external transactions and the start-up/shut-down of gas turbines. The inconsistencies the NYISO is working to address can result in unforeseen ramp constraints, undermine the accuracy of prices forecasted by RTC, and could contribute to transient shortage conditions and unnecessary price volatility. The 2016 project will investigate possible revisions and adjustment to the look-ahead RTC and RTD evaluations.

After the possible revisions and adjustments are identified, costs to change the NYISO's market software, as well as impacts to the solution time and RTC/RTD scheduling and pricing must all be considered when deciding if the NYISO will implement the potential improvements that it identifies. Though the project has not been discussed at length, should the project find possible improvements, the total implementation time from initial discussion with stakeholders to market implementation is estimated to be considerable, given the NYISO's EMS/BMS System Upgrade project.[13]

Commission Question

2. Please list all of the unit commitment and dispatch processes that execute after the close of the day-ahead energy market, up to and including all unit commitment and dispatch processes used in the real-time market. Please indicate whether each process uses look-ahead modeling. With respect to each process that uses look-ahead modeling, please address each of the topics listed below and include examples where possible.

NYISO Response

The NYISO Security Constrained Unit Commitment (SCUC) reliability commitment process is embedded in its Day-Ahead Market (DAM) process. After DAM closes, if there is a significant change to the system (*e.g.* the loss of a generator or a transmission element) additional generators may be committed through the Supplemental Resource Evaluation (SRE) process. Units may be SRE'd by the NYISO operators, or at the request of a Transmission Owner. Generators committed via SRE are eligible to set price in real-time.[14] SREs

[13] The EMS/BMS Upgrade project is currently underway and scheduled for completion in 2019. This effort will limit the NYISO's ability to make additional energy market modifications.

[14] SRE commitments are at a unit's Minimum Generation level. Additional, economic Incremental Energy dispatch from an SRE-committed unit is eligible to set price.

commitments do not use look-ahead modeling, but RTC and RTD will include SREs within their respective look-ahead optimization horizons.

The SRE process is described in the NYISO's Transmission and Dispatching Operations Manual, Section 5.7.6, Supplemental Commitment Process:

> The NYISO may use the SRE process to commit additional resources outside of the SCUC and RTC processes to meet NYISO reliability or local reliability requirements. Transmission Owners (TOs) may request the commitment of additional generators to ensure local reliability in accordance with the local reliability rules. The NYISO will use SREs to fill these requests by TOs. In addition, Generator Owners may request the operation of a specific steam unit if certain combustion turbines have an energy or a non-synchronous reserve schedule that necessitates operation of the steam unit due to 24-hour NO_X Averaging Period requirements.
>
> When the NYISO requests that generators submit bids in response to an SRE, ICAP suppliers must offer their available capacity unless an offer is pending in the Real Time market when the SRE request is made or the unit is unable to run due to an outage, operational issues or temperature derates. Special Case Resources are not required to respond to SRE requests by section 5.12.1 of the Market Services Tariff. However, the NYISO may request SCR and EDRP resources to respond to SRE requests on a voluntary basis.
>
> Since SREs are only performed to address reliability concerns, it is intended that units committed by the SRE process fulfill their obligation by physically operating.
>
> ***NYISO Requests for SREs***
>
> The NYISO may perform SREs in response to the following [two] conditions:
>
> 1. When Day-Ahead reliability criteria violations are forecast after SCUC has begun or completed its Day-Ahead evaluation (*i.e.*: too late for additional day-ahead commitments).
>
> 2. When In-Day reliability criteria violations are anticipated more than 75 minutes ahead (*i.e.*: too early for RTC commit additional resources).

Additional commitment procedures that occur after SCUC and ordinarily after SREs include the Real Time Commitment (RTC) and Real Time Dispatch (RTD). RTC executes every quarter hour and includes a two-and-a-half hour look-ahead with advisory commitments over the look-ahead period. RTD follows RTC, and both optimizations utilize look-ahead capability. The NYISO's RTD executes every five minutes and includes a 55 to 65 minute look-ahead, depending on the interval. The RTC and RTD look-ahead commitment processes are described in greater detail in the NYISO's response to Look Ahead Modeling question 2(a), below.

From time to time, NYISO operations may implement the Real Time Dispatch – Corrective Action Mode (RTD-CAM) when the need arises to respond to system conditions that were not anticipated by RTC or the regular RTD. RTD-CAM is used to deal with immediate system issues quickly and was constructed to minimize execution time, thus RTD-CAM intervals do not utilize look-ahead modeling. RTC, RTD, and RTD-CAM are further described in the NYISO's response to Look Ahead Modeling question 2(a) below.

Manual commitments may also occur after SCUC runs. Such commitments are described in the NYISO's answer to question 3 in the "Commitments to Manage Multiple Contingencies" section of this Report.

Commission Question

2. Please list all of the unit commitment and dispatch processes that execute after the close of the day-ahead energy market, up to and including all unit commitment and dispatch processes used in the real-time market. Please indicate whether each process uses look-ahead modeling. With respect to each process that uses look-ahead modeling, please address each of the topics listed below and include examples where possible.

    a. Please indicate whether the process uses look-ahead modeling solely as an advisory tool for operators or, alternatively, whether the process uses look-ahead modeling to make actual commitment, dispatch, and pricing decisions. What is the time horizon considered by the look-ahead model? What are the commitment/dispatch intervals considered by the look-ahead model? How frequently does the model execute throughout the operating day (e.g., every 15 minutes, every 30 minutes)?

NYISO Response

The NYISO look-ahead modeling process instructs actual commitment and dispatch decisions, while also providing resources with advisory prices and schedules. The Real Time Commitment (RTC) program makes binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run. RTC provides advisory commitment information for the remainder of the two and a half hour optimization period, and produces binding schedules for External Transactions to begin at the start of each quarter hour. RTC co-optimizes to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements and to minimize the total as-bid production costs over its optimization timeframe. RTC considers SCUC's Resource commitment for the day, load forecasts from the load forecasting program and loss forecasts that RTC itself produces each quarter hour, binding transmission constraints, and all real-time Bids and Bid parameters. Advisory prices, as well as some of the binding external proxy generator prices, are produced by RTC.

The NYISO's Real-Time Dispatch (RTD) program does not make commitment decisions and will generally not consider start-up costs in any of its dispatching or pricing decisions.[15] Each RTD run co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon. In addition to producing binding schedules and the majority of binding prices for the next five minutes, each RTD run will produce advisory schedules and prices for the remaining

[15] As explained in the NYISO's response to Pricing of Fast Start Resources question 3(c), RTD considers the start-up costs of non-committed 10-minute eligible resources that are qualified to set price.

four time steps of its bid-optimization horizon. RTD uses the most recent system information and the same set of Bids and constraints that are considered by RTC.

When the NYISO needs to respond to system conditions that were not anticipated by RTC or the regular RTD, such as the unexpected loss of a major generator or transmission line, NYISO operators will activate the specialized RTD-Corrective Action Mode (RTD-CAM) program. RTD-CAM runs are nominally either five or ten minutes long and, by design, do not include look-ahead capability in order to minimize execution time. Operators manually execute each RTD-CAM. Unlike RTD, RTD-CAMs can commit 10-minute start resources. When RTD-CAM is activated, the NYISO has the ability to implement various measures to restore normal operating conditions. Section 6.2 of the NYISO's Transmission and Dispatching Operations Manual provides additional details on RTD-CAMs.[16]

[16] Link to Transmission and Dispatch Operations Manual: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/trans_disp.pdf

Commission Question

2. Please list all of the unit commitment and dispatch processes that execute after the close of the day-ahead energy market, up to and including all unit commitment and dispatch processes used in the real-time market. Please indicate whether each process uses look-ahead modeling. With respect to each process that uses look-ahead modeling, please address each of the topics listed below and include examples where possible.

    b. Please discuss whether and how look-ahead modeling affects real-time price formation and/or operational efficiencies (especially with respect to the commitment and pre-positioning of fast-start and flexible resources).

NYISO Response

i. **Please explain whether and how the RTO's/ISO's look-ahead model pre-positions the dispatch of resources in anticipation of system needs, especially with respect to expected near-term needs for ramping capability. Please explain whether and how the RTO's/ISO's look-ahead model optimizes the commitment of resources in anticipation of system needs.**

Look-ahead features are part of both RTC and RTD, each of which are based on the minimization of production costs to meet power system needs through commitment of resources and ramping of resources. Achieving a least production cost commitment and dispatch requires recognition of inter-temporal constraints (*e.g*. ramp and minimum run time constraints). The RTC horizon is nominally two and a half hours and the RTD optimization horizon is 55 to 65 minutes, depending on the interval. RTC and RTD commit and dispatch to resolve anticipated inter-temporal constraints in the look-ahead intervals. RTC and RTD minimize costs over all look-ahead intervals, but only the first interval is binding. All other look-ahead intervals are advisory.

RTC may elect to commit or schedule otherwise uneconomic resources, including generation and/or interchange, in order to ensure sufficient ramp capability is available to meet anticipated changes in resource commitments/de-commitments, changes in load or transmission outages, with the goal of minimizing production costs over the entire look-ahead interval. Likewise, RTD may elect to ramp otherwise uneconomic resources early in the hour-long optimization horizon in order to ensure sufficient ramp capability is available to meet anticipated changes due to resource commitments/de-commitments, load, interchange ramps or transmission outages.

ii. If the RTO/ISO uses look-ahead modeling to make unit commitment decisions, how far in advance of real-time does the operator issue commitment instructions? Does this time period for issuing commitment instructions differ by resource characteristics, such as start-up time?

There are two mechanisms to get commitment decisions prior to the start of the Real-Time Market. The first is the DAM which posts results by 11:00 on the day before the real-time operating day. The second is the SRE process, which can be engaged if unexpected conditions occur after the close of the DAM. If the SRE process is implemented, results are posted as soon as the decision is made by the operators.

RTC software makes commitment decisions in real-time. RTC makes binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run. RTC provides advisory commitment information for the remainder of the two and a half hour optimization period, and produces binding schedules for External Transactions to begin at the start of each quarter hour.

SCUC and RTC each take into account a generator's start-up time. RTC can start-up generators with 30-mintue and 10-minute start-up times.

iii. Please explain whether and how look-ahead modeling affects real-time prices. In this regard, please explain whether and how the look-ahead model calculates actual real-time prices, and whether and how constraints in future periods affect price formation.

The real-time price (LBMP) is calculated in RTD recognizing the inter-temporal constraints, such as ramp constraints, expected future system topology changes (such as the scheduled outage of a transmission line), future resource availability changes (such as the forced outage of a generator that received a Day-Ahead schedule), load changes, etc. Thus, future constraints can affect the binding period real-time price.

Whenever there is an intertemporal constraint such that a change in future dispatch costs will occur due to a dispatch decision made in the initial time step, all of the incremental costs must be included in the price of the initial time step in order to properly evaluate whether the least-cost dispatch decision is made.

Consider a scenario with four generators that must be scheduled to minimize production cost while respecting physical parameters including the Upper Operating Limit (UOL), minimum generation limit and ramp rate of each generator. The look-ahead example in Table 1 (below) is contrasted with examples that do not include look-ahead capability in Tables 2a and 2b. The initial condition at 9:30 in Table 1 shows an incremental cost of $5.00, which is exactly the same as the 9:30 interval in the set of conditions in Table 2a. The 9:45 interval in Table 1 has incremental cost of $10.00 because Generator A has been dispatched upward to serve load; the optimization horizon in the look-ahead case recognizes that Generator C must shut-down at 10:00 and Generator A is dispatched up in anticipation of Generator C's shut-down.

Conversely, the case in Table 2a does not include Generator C turning off at 10:00 in its optimization horizon and thus does not move Generator A; the incremental cost calculated in Table 2a for 9:45 remains at $5.00 (slightly lower than Table 1). However, in Table 2b the 10:00 interval reflects a $25.00 incremental cost to commit Generator D in order to accommodate the shut-down of Generator C. The incremental cost in Table 2b is significantly higher than the incremental cost in Table 1 for the 10:00 interval.

In the example, look-ahead modeling avoids the need to commit the quick start unit (Generator D) to serve load, as well as the price spike associated with that commitment.

"With Look-Ahead" Table 1

	Minimum Generation (MW)	Upper Operating Limit (MW)	Ramp Rate (MW/minute)	Incremental Cost ($/MWh)		Initial Conditions (at 9:30)	9:45	10:00	10:15	10:30	10:45
Load						100	100	100	100	100	100
Gen A	5 MW	75 MW	2	$ 10.00		5 MW	20 MW	50 MW	35 MW	25 MW	25 MW
Gen B	5 MW	75 MW	1	$ 5.00		20 MW	35 MW	50 MW	65 MW	75 MW	75 MW
Gen C	5 MW	75 MW	2	$ 1.00		75 MW	45 MW	OFF	OFF	OFF	OFF
Gen D	30 MW	30 MW	2	$ 25.00		OFF	OFF	OFF	OFF	OFF	OFF
LBMP						$ 5.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00

"Without Look-Ahead" Table 2a

	Minimum Generation (MW)	Upper Operating Limit (MW)	Ramp Rate (MW/minute)	Incremental Cost ($/MWh)		Initial Conditions (at 9:30)	9:45
Load						100	100
Gen A	5 MW	75 MW	2	$ 10.00		5 MW	5 MW
Gen B	5 MW	75 MW	1	$ 5.00		20 MW	20 MW
Gen C	5 MW	75 MW	2	$ 1.00		75 MW	75 MW
Gen D	30 MW	30 MW	2	$ 25.00		OFF	OFF
LBMP						$ 5.00	$ 5.00

"Without Look-Ahead" Table 2b

	Minimum Generation (MW)	Upper Operating Limit (MW)	Ramp Rate (MW/minute)	Incremental Cost ($/MWh)		Initial Conditions (at 9:45)	10:00
Load						100	100
Gen A	5 MW	75 MW	2	$ 10.00		5 MW	35 MW
Gen B	5 MW	75 MW	1	$ 5.00		20 MW	35 MW
Gen C	5 MW	75 MW	2	$ 1.00		75 MW	OFF
Gen D	30 MW	30 MW	2	$ 25.00		OFF	30 MW
LBMP						$ 5.00	$ 25.00

iv. Please discuss whether and how look-ahead modeling can reduce out-of-market commitments by operators.

Prepositioning the system to address anticipated future constraints can increase the number of solutions available and thus reduce the need for out-of-market commitments. If the NYISO did not have look-ahead modeling in RTC and RTD that incorporates ramp rates, minimum run time, minimum down time, and other generator commitment parameters, the

NYISO's operators would be required to intervene more frequently in the NYISO's commitment and dispatch process.

v. Please explain whether and how look-ahead modeling provides greater benefits when used to make actual market decisions rather than solely as an advisory tool for operators.

RTC and RTD minimize production cost over their respective evaluation horizons. Each program makes market decisions. The look-ahead modeling sends the right signal to the marketplace to preposition resources in anticipation of expected future events. Having RTC and RTD utilize look-ahead modeling to make decisions allows the commitment and dispatch process to build upon previous decisions. The market software with its look-ahead capability is able to commit and dispatch more quickly, consider more variables and, generally, to realize a lower total production cost relative to what an operator could achieve if the software was used only as an advisory tool.

Incorporating look-ahead modeling into the market solution minimizes the manual processes and operator decisions that would be required if look-ahead modeling is only used as an advisory tool for operators. During dynamic system conditions and events it can be challenging for operators to identify the appropriate commitments as quickly as an automated market solution.

vi. **Please discuss any other potential or actual benefits from look-ahead modeling.**

As explained above, look ahead modeling provides a more accurate representation of system conditions and allows for the anticipation of ramp constraints, resulting in more accurate instructions to resources and more efficient scheduling with neighboring control areas.

Commission Question

3. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, related to look-ahead modeling. For any look-ahead modeling enhancements that the RTO/ISO and/or its stakeholders are currently considering, please discuss any evaluation of the costs and/or complexities of look-ahead modeling relative to its potential benefits, and the estimated time frame for implementation of any look-ahead modeling enhancements.

    a. Are there any features of existing look-ahead models that could adversely affect price formation (for instance, are there any instances in which existing look-ahead model designs could lead to inaccurate price signals)? If so, please describe these features in detail and discuss whether any improvements are warranted.
    b. Please describe any other challenges, complexities, or practical limitations associated with look-ahead modeling. Where possible, please provide quantitative examples.

NYISO Response

As discussed in the NYISO's response to Look-Ahead Modeling question 1, the "RTC-RTD Forward Horizon Coordination Improvements" market design project slated for 2016 will be considering the slight modeling inconsistencies between the RTC and RTD look-ahead evaluations that arise as the two programs evaluate external transactions and the start-up/shut-down of gas turbines, and will investigate possible revision and adjustment of the look-ahead RTC and RTD evaluations to address the identified inconsistencies.

D. Uplift Allocation

Commission Questions

1. Please provide a high-level overview of the RTO's/ISO's existing framework for allocating uplift charges (e.g., briefly explain the principles that guide the RTO's/ISO's allocation of uplift charges and summarize at a high level how these principles are applied in the day-ahead and real-time energy and ancillary services markets).

NYISO Response

The NYISO's cost allocation rules are designed to differentiate and categorize uplift costs based on the underlying cause of such costs.[17] In doing so, the NYISO identifies whether uplift costs are attributable to actions taken to ensure statewide reliability or actions taken to address local reliability.

The NYISO allocates uplift costs consistent with "beneficiaries pay" principles (*i.e.*, those receiving the benefits of a given action ultimately bear its costs). Uplift payments to ensure statewide reliability are allocated to all loads in the New York Control Area (NYCA), while uplift costs associated with local reliability issues are allocated only to the load within the transmission district for which the local reliability actions were taken.[18] Real-time uplift costs are allocated to the applicable loads on a Load Ratio Share basis, based on the actual real-time metered load during the hours in which such uplift costs were incurred.

[17] As further described in its response to Transparency question 1, the NYISO provides regular reporting to its Market Participants and to the public detailing the categorization and assignment of various uplift costs.

[18] The NYISO's existing uplift allocation procedures are consistent with the recommendations of Potomac Economics in that the NYISO categorizes uplift costs based on the underlying cause and then allocates costs based on cost causation principles. *See* Potomac Economics Price Formation Comments at 16-18.

Commission Questions

2. Please identify any specific areas where the RTO/ISO believes that its existing uplift allocation methodology needs improvement. Please discuss these areas, along with any RTO/ISO and/or stakeholder initiatives or plans aimed at improving uplift allocation.

   a. Please identify any specific transaction types, resource types, schedule deviations, or other uplift drivers that cause uplift on a regular basis, but do not receive an allocation of uplift charges under current market rules.
   b. Please discuss the complexity of re-designing existing market rules and settlement systems to better align uplift allocation with cost-causation principles. Please provide a qualitative assessment of whether and how the potential benefits of improved uplift allocation outweigh the cost and complexity of implementation and application.
   c. Commission staff's 2014 paper on uplift noted that a small number of resources receive the majority of uplift payments in every RTO/ISO. Additionally, PJM asserts that existing uplift allocation rules likely mute investment signals due to lack of clarity regarding where uplift payments are being received, and asks the Commission to provide guidance on principles for uplift allocation. Please identify any specific areas where the RTO's/ISO's current uplift allocation methodology could potentially mute investment signals.

NYISO Response

The NYISO's method is designed to allocate the cost of uplift to the customers that are benefitting from the action that caused the uplift. The allocation of uplift to external transactions could be improved. The NYISO supports the reciprocal elimination of uplift and other fees allocated to external transactions. The allocation of uplift and other fees reduces trade between regions and adversely impacts total production costs.

To ensure that its revenues cover the expected uplift costs and other transaction fees, a Market Participant will submit an external transaction request when the expected price difference between regions exceeds the expected total fees. In financial terms, the participant will incorporate a margin into its offer to cover the expected fees. This rational behavior prevents price convergence between regions. System costs will be higher than necessary because the interties will tend to be under-utilized, relative to external transaction volumes if there were no per-megawatt transaction fees. In economic terms, transaction fees on external transactions act like a ‘hurdle’ that deters trade and distorts production costs upward.

Allocating uplift and other transaction fees to external transactions impedes price convergence between regions and raises system production costs. The magnitude of the benefits to loads from eliminating an uplift allocation to external transactions, in the form of lower LMPs due to greater inter-regional competition, could exceed the cost of uplift and transaction fees that must be recovered from other sources.

Other than addressing the allocation of uplift to external transactions, the NYISO has not identified any areas for improvement where its allocation of uplift mutes appropriate price or investment signals. The NYISO has not identified any areas where the benefits of changing its uplift allocation methods would outweigh the costs associated with doing so. The NYISO already identifies individual sources of uplift, down to specific operator actions or market participant requests, to ensure that uplift is properly allocated, and continually seeks ways to improve the transparency of the amount of uplift payments. Please see the NYISO’s response to Transparency question 2 for more details about how it reports on and assigns the costs associated with actions taken to protect system or local reliability.

The NYISO has a settlements simulator that allows it to understand expected settlement impacts before the NYISO proposes changes to its market rules. This settlement simulator has become an invaluable tool when the NYISO evaluates its hypothesis and rationale for changing market and/or settlement rules.

Commission Questions

3. Please explain the methodology by which the RTO/ISO allocates day-ahead and real-time energy and ancillary services market uplift, including an explanation of whether and how the allocation rules follow cost-causation principles. [fn. Please include in this response a discussion of virtual transactions.] In this regard, please explain the following (referencing specific charge codes to the extent that it is practical):

    a. Explain whether and how day-ahead and real-time energy and ancillary services market uplift is allocated to transactions that cause the commitment of resources that receive uplift payments;
    b. Explain whether and how the RTO/ISO allocates real-time energy and ancillary services market uplift to market participants' deviations from day-ahead schedules, and whether and how deviations that increase the need for actions that cause uplift (harming deviations) are netted against deviations that reduce the need for actions that cause uplift (helping deviations);
        i. explain whether and how uplift related to real-time resource commitments for transmission constraint management is allocated to schedule deviations;
        ii. explain whether and how uplift related to real-time resource commitments for system reliability is allocated to schedule deviations;
    c. Explain the locational granularity with which this uplift is allocated (e.g., RTO-wide, zonally);
        i. explain whether and how uplift related to real-time resource commitments for voltage and local reliability is allocated to local transmission areas or zones;
    d. Explain whether day-ahead and real-time energy and ancillary services market uplift is allocated on an hourly, daily average, or another basis;
    e. Discuss and explain whether there are certain components of day-ahead and real-time energy and ancillary services market uplift that cannot be allocated consistent with cost-causation principles, and if so explain how these are allocated;
    f. Explain the conditions under which the RTO/ISO exempts from the allocation of each charge any market participants, transactions, or schedule deviations that would otherwise receive an allocation, and explain the rationale for such exemptions.
    g. Finally, list and explain the categories of transactions, or schedule deviations to which the RTO/ISO allocates day-ahead and real-time energy and ancillary services market uplift charges. For the period spanning October 1, 2014 through September 30, 2015, report the share of day-ahead energy and ancillary services market uplift (in percentage terms) allocated to each category. Similarly, report the share of real-time energy and ancillary services market uplift allocated to each category over the same time period. Do not identify any specific market participants.

NYISO Response

The NYISO has three major categories of uplift:

1) Bid Production Cost Guarantees (BPCG) - both Day-Ahead and real-time: A make-whole payment paid primarily to generators when a unit's cost to run has exceeded its LBMP + ancillary service revenue for the time period committed by the NYISO. Generators must bid such that the NYISO commits the unit in order to be eligible to receive a BPCG. Self-Committed generators are not ordinarily eligible for BPCG payments.[19]

2) Day Ahead Margin Assurance Payments (DAMAP) – The NYISO will make a generator "whole" to its Day-Ahead margin if the unit is committed in real-time and actions required of the unit in real-time cause the Day-Ahead margin to be reduced. Reductions in Day-Ahead margins due to real-time dispatch instructions can result from a NYISO or Transmission Owner (TO) directive to deviate from the Day-Ahead schedule in real-time or from a change in the transmission system.

3) Supplemental Event Credits – Events such as large event reserve pickups and maximum generation pickups that require generators to ramp to their maximum capability for a short window of time as required by NYISO Operations.

For the period of October 2014 through September 2015, the total uplift that was allocated to NYISO markets is approximately $87 million, which is roughly 1.7% of the total cost of the NYISO's $5.2 billion energy market during the same time period. All cost values/percentages in this discussion are based on this time period. The corrected table below summarizes the categories and significant causes of NYISO uplift payments.

[19] Generators that self-commit in real-time in order to start-up to meet a Day-Ahead schedule and generators that self-commit in response to an SRE request may remain eligible to receive BPCG.

NYISO Uplift Payments October 2014 - September 2015	
	% of Total Uplift
DA BPCG	58%
- DARU	32%
- Economic Commitment	26%
RT BPCG	31%
- SRE	10%
- ISO Reliability Commitment	3%
- TO Relibility Commitment	7%
- Other	2%
- Economic Commitment	9%
Supplemental Event BPCG	<1%
DAMAP	10%
- ISO/ Other Reliabilty reasons	9.5%
- TO Reliability	<1%
NYISO Uplift Total = $87M	
NYISO Energy Market Total = $5.2B	

The NYISO's uplift cost allocation method is primarily based on a "beneficiary pays" model. All uplift allocations are based on Load Ratios Shares (at different levels of granularity that are discussed below) based on real-time physical Load. Allocations are based on either New York Control Area (NYCA)-wide shares (including export and wheel-through transactions as applicable) or subzonal Load Ratio Shares. The NYISO is made up of 11 zones and 23 subzones. The subzones are areas of load broken up by the service districts of the local Transmission Owners (TOs) operating in the particular zone. Costs are allocated NYCA-wide if the cause of the uplift was a NYISO directive to address state-wide reliability, or to local subzone if the local TO directed the action. In either case, the cost allocation is based on a *pro-rata* allocation of the responsible LSEs' Load Ratio Shares in the relevant area (all NYCA or local). This means that Day-Ahead and Real-Time energy and ancillary services Market uplift is not allocated to the transactions that cause the commitment of resources, but rather is allocated to the Load that benefits from the commitment of the resources.

While the NYISO allocates all components of energy and ancillary service market uplift using the "Beneficiary Pays" model, external transactions scheduled as part of Coordinated Transaction Scheduling (CTS) with ISO-NE are exempt from such allocations. That initiative reciprocally eliminated all NYISO and ISO New England fees on CTS transactions between the two control areas. As discussed in the NYISO's answer to Uplift question 2, the NYISO supports the reciprocal elimination of uplift and other transaction fees on exports because these fees reduces trade between regions and adversely impact total production costs.

The assignment of uplift based on deviations from schedules is a key subject in the Commission's question 3(a) and 3(b)(i) and (ii). The NYISO's approach recognizes that real-time physical load generally benefits from the actions that cause uplift, whether the uplift arises in the Day-Ahead or the Real-Time Market.

The NYISO's market structure has only one payment that links Day-Ahead schedules to real-time output, which is the DAMAP. Otherwise, settlements for the Day-Ahead and Real-Time Markets are not coupled. Thus, actual energy withdrawals are generally allocated uplift costs. There is a very small subset of uplift costs that are recovered from both virtual supply transactions and physical load. This uplift comes from additional commitments in the Day-Ahead Market to meet the NYISO's forecast load.

The NYISO manages schedule deviations in several ways. For deviations where a generator exceeds its real-time schedule, the generator will only be paid for energy produced in excess of its schedule up to 3% of its Upper Operating Limit (UOL). Generators that consistently produce less energy than they are scheduled to produce in real-time may be assessed an under generation penalty.[20] In addition, generators that do not produce the MWs they were scheduled to provide Day-Ahead in real-time are subject to a balancing obligation.

<u>BPCG Discussion</u>

Bid Production Cost Guarantees (BPCGs) are uplift payments made when a generator's revenues from Energy and Ancillary Services (Regulation, Reserves, and Voltage Support) do not at least equal its bid cost of providing those products for a given commitment day. There are different reasons why BPCG payments may be necessary, but the payments often result when a generator is committed to address a reliability need via one of the following commitment methods, Local Reliability Rules (LRR), Day-Ahead Reliability Unit (DARU), Supplemental Resource Evaluation (SRE), or Out-of-Merit Generation (OOM). It is not unusual for a unit to be committed economically for start-up and for a portion of the day, but to still receive a BPCG settlement for the day as a result of changing conditions over the course of the day, or as a result of minimum run time and/or minimum down time requirements that require a Generator to run at times when its operating costs exceed the LBMP. Since BPCG is determined over the course of the day and not a smaller time period, it is quite possible for a generator to receive a BPCG payment and still be part of the "least cost" commitment solution.

Day Ahead BPCG may be paid to generators that were committed economically in the Day-Ahead Market, but where the LBMP and ancillary service revenues produced for the entire commitment period are not sufficient to cover the generator's full cost of operation. Day-Ahead BPCG represents approximately 58% of the NYISO's total market uplift. The uplift cost associated with economic commitments is approximately 26% of NYISO's total market uplift

[20] *See* Services Tariff Sections 15.3.5.3, 15.3.5.5.1, 15.3.5.5.2 and 15.3A.1.

(and 45% of total Day-Ahead BPCG payments). Day-Ahead BPCG is also paid to generators that are committed through the DARU process. The DARU process identifies generators that are needed for reliability, and commits them *if* they are not committed economically in the Day-Ahead Market.[21] DARU units are eligible to receive a Day-Ahead BPCG if their bid costs exceed their LBMP and ancillary service revenues for the commitment day. The cost of DARU commitments (which are frequently requested to address local reliability) are allocated based on subzonal Load Ratio Shares. DARU uplift costs represent 55% of Day-Ahead BPCG and 32% of the total NYISO market uplift.

As with Day-Ahead BPCG, real-time BPCG compensates generators for costs to run that are not recovered through LBMP or ancillary service revenues. Unlike Day-Ahead BPCG, costs for real-time BPCG are allocated based on the source of the commitment that required the unit to run. For example, when a generator that is committed at the request of a Transmission Owner to address a reliability need, either via an SRE[22] or OOM,[23] any resulting BPCG costs are allocated to the subzone that the generator is located in. When the NYISO commits a generator in real-time to address a statewide reliability need, the uplift costs associated with that commitment are allocated NYCA-wide, irrespective of the location of the unit being committed.

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[21] Section 1.4 of the NYISO OATT defines a DARU as "A Day-Ahead committed Resource which would not have been committed but for the commitment request … in order to meet the reliability needs of the …system which request was made known to the ISO prior to the close of the Day-Ahead Market."

[22] Section 1.19 of the NYISO OATT defines an SRE as "a determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day." Uplift resulting from an SRE commitment may be allocated statewide or to a local transmission zone, depending on the reliability need that required the commitment.

[23] Section 1.15 of the NYISO OATT defines OOM as "[r]esources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch."

OOM commitment and redispatch occur more frequently than SRE commitments and OOM status can be used to address a more diverse set of reliability concerns. However, OOM is not as significant a cause of uplift as SRE or DARU. Some of the common OOM types that are used to commit, de-commit or redispatch generators include:

Committed for ISO Reliability

Committed for TO Reliability

Generator Request (various reasons)[24]

Operator Intervention (various reasons)[25]

Start Up/ Shut Down

For the purposes of this discussion, the NYISO addresses the two reliability based OOM categories because those are the two categories that commonly generate uplift. Real-time BPCG resulting from OOM reliability commitments OOM dispatch limitations reflects approximately 10% of uplift for the time period discussed. Approximately 3% of real-time uplift is related to ISO reliability commitments, while the remaining 7% is attributable to Transmission Owner reliability commitments.

Day-Ahead Margin Assurance Payments

In certain instances, if a generator with a Day-Ahead energy, regulation, or operating reserves schedule is required to buy out of those schedules in real-time, a Day-Ahead Margin

[24] Generator requested OOM operation often occurs to address generator that is not able to operate within its normal operating limits. The NYISO has specific tariff rules in place to limit the potential for generator-requested changes to operating parameters to cause uplift. *See* the NYISO's August 22, 2008 filing in FERC Docket No. ER08-1438, which was accepted in a Letter Order issued on September 18, 2008.

[25] NYISO operators may use OOM to address generators that are not responding to dispatch instructions. *See* the NYISO's August 22, 2008 filing in FERC Docket No. ER08-1438, which was accepted in a Letter Order issued on September 18, 2008.

Assurance Payment (DAMAP) is available to protect the generator's Day-Ahead margin. Section 25.1 of the Services Tariff states:

> The purpose of [DAMAP] is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (I) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

An example of a circumstance which may result in an obligation to pay DAMAP is when real-time operations diverge from what was expected Day-Ahead. For example, Gas Turbines (GTs) generally have minimum down times. If the NYISO economically commits a GT to run in real-time, after the GT is turned off it may no longer be able to return to satisfy its Day-Ahead schedule (for energy or non-synchronous reserves) and must "buy out" of its Day-Ahead schedule at real-time prices (it has a balancing obligation). In this circumstance, the NYISO will make the generator "whole" to its Day-Ahead margin by paying a DAMAP for the affected hours.

DAMAP is allocated based on the reason the generator diverged from its Day-Ahead schedule. If a Transmission Owner took an action that prevented a generator from operating to achieve its Day-Ahead schedule, the associated de-rate is allocated via subzonal Load Ratio Shares. Other causes of DAMAP are allocated NYCA-wide based on Load Ratio Shares.

DAMAP payments comprise only 10% of total market uplift for the period in question. Of that, roughly 5%of the DAMAP uplift is associated with local reliability requests, with 95% of DAMAP payments (~9.5% of total uplift) being the result economic commitments or NYISO reliability calls. The remaining DAMAP costs resulted from unusual OOM commitments or dispatches. Examples of these types of unusual commitments or dispatches include generator request to modify their Upper Operating Limit due to real-time conditions, generators that are set

OOM for testing, or generators that are set OOM to permit the NYISO to conduct an audit of the generator's capabilities.

Supplemental Event Credit

For intervals in which the ISO has called a large event reserve pick-up or a maximum generation pickup, any Supplier who meets certain eligibility requirements[26] is eligible to receive a special interval-level BPCG. Large event reserve pick-ups are not uncommon, but are usually limited to short durations.[27] The real-time BPCG costs associated with supplemental events represent less than 0.5% of all uplift payments. All supplemental events are allocated NYISO-wide, as only the NYISO operators can initiate a large event reserve pick-up or a maximum generation pickup.

Commission Questions

4. Some commenters suggest that MISO's uplift allocation methodology matches cost-causation principles and represents an industry best practice.

    a. Please discuss the advantages and disadvantages of MISO's approach, and discuss whether it represents an industry best practice.
    b. Please discuss whether other RTOs/ISOs should create allocation categories that relate to the underlying causes of uplift, and how these categories should be defined. Discuss the types of uplift costs that can be assigned to cost-causation categories. What types of uplift costs, if any, cannot be readily assigned such categories? Why are such uplift costs difficult to categorize in accordance with cost-causation?

[26] *See* Services Tariff Section 18.5.1.

[27] During the period discussed in this response (October 2014 through September 2015) there were 121 cases of reserve pick-ups and no maximum generation pick-ups. The reserve pickups normally impacted individual 5 minute intervals, resulting in minimal uplift payments.

NYISO Response

The NYISO is not familiar enough with the MISO uplift allocation methodology to discuss the MISO uplift allocation methodology in detail. The NYISO allocates uplift costs consistent with "beneficiaries pay" principles (*i.e.*, those receiving the benefits of a given action ultimately bear its costs), which is consistent with the recommendations of Potomac Economics.[28] Similar to the MISO, the NYISO categorizes uplift costs based on the underlying cause and then allocates costs based on cost causation principles. Uplift payments to ensure statewide reliability are allocated to all loads in the New York Control Area, while uplift costs associated with local reliability issues are allocated only to the load within the transmission district for which the local reliability actions were taken.

Commission Question

5. Please discuss other potential approaches to allocating uplift charges based on cost-causation, and explain the potential advantages and disadvantages of such approaches.

NYISO Response

The NYISO is not familiar enough with uplift allocation approaches that differ from the approaches that the NYISO employs to discuss the potential advantages and disadvantages of such alternative approaches.

[28] *See* Potomac Economics Price Formation Comments at 16-18.

Commission Questions

6. Some commenters argue that allocating uplift charges to virtual transactions reduces the volume of such transactions, thereby impeding the convergence of day-ahead and real-time energy prices, while other commenters argue that RTOs/ISOs should allocate a portion of uplift charges to virtual transactions.

    a. Please discuss whether and how the RTO's/ISO's uplift allocation methodology nets virtual transactions or other deviations from day-ahead schedules for purposes of allocating uplift charges. Please discuss the advantages and disadvantages of such practices in the context of cost causation and the convergence of day-ahead and real-time prices.
    b. Please discuss the advantages and disadvantages of allocating to virtual transactions a portion of the uplift charges associated with the day-ahead market alone (and not allocating to virtual transactions any uplift charges associated with the real-time market), and whether such an approach is consistent with cost-causation principles.

NYISO Response

Virtual bidding should improve price convergence by correctly incentivizing Virtual Loads to only purchase when Day-Ahead prices are expected to be lower than real-time prices – thereby by helping Day-Ahead Market and Real-Time Market prices converge. A Virtual Supply transaction will make money if it is sold in an hour and at a location where the Day-Ahead price is higher than real-time price, thereby also aiding the convergence of the Day-Ahead and Real-Time Markets.

Uplift is generally not allocated to Virtual Load because it is not the beneficiary of the action that generated the uplift and because in well structured markets Virtual Loads do not have incentive to impact uplift. Excessive scheduling of Virtual Load could drive the commitment of more Day-Ahead generation than is necessary to meet the real-time Load. In this case, the Virtual Load should be purchasing energy at a higher Day-Ahead price than the real-time price it is selling back its energy at. Allocating additional uplift to this transaction could increase the cost of this 'bad deal,' but that allocation would also increase the cost for Virtual Load transactions that improve convergence between Day-Ahead and real-time prices, and therefore improve the NYISO's Day-Ahead commitment.

Excessive scheduling of Virtual Supply could cause insufficient generation to be committed in the Day-Ahead Market. The NYISO protects against this possibility by including an integrated forecast load commitment pass in its Day-Ahead Market that commits sufficient generation to meet the next day's load forecast. Because it is possible that Virtual Supply would impact the need for reliability commitments, Virtual Supply is allocated a portion of the uplift that is caused by Day-Ahead forecast load commitments.

However, the majority of uplift results from physical dispatch. Therefore, from a cost-causation standpoint there is no real benefit to allocating uplift costs to Virtual Load or Virtual Supply transactions.[29] It would not be appropriate to allocate physical uplift to Virtual Load, even though the commitment of Virtual Load has an impact on Day-Ahead to real-time price convergence.

E. Transparency

<u>Commission Question(s)</u>

1. Please provide an up-to-date description of the RTO's/ISO's efforts or plans, if any, to address any RTO/ISO-specific transparency shortcomings. Are there any RTO/ISO and/or stakeholder initiatives to improve the transparency of data released publicly about uplift, operator actions, and other changes to the market parameters that can affect market clearing prices? If so, please describe any plans and related timelines.

[29] There is minimal uplift (forecast BPCG) allocated to Virtual Load, but it is insignificant compared to total uplift. The total uplift costs related to forecast deviations is approximately $53 thousand during the period in this document. This is not a significant amount as compared to the $80 million in total uplift for the reported period.

NYISO Response

Over time, the NYISO has revised and enhanced its data reporting and the format in which such information is presented based on feedback from stakeholders and based on its own internal review. Such enhancements are aimed at improving clarity and making data and information more readily accessible and easily comprehensible. For example, the NYISO's Market Operations Report[30] and Operations Performance Metrics Monthly Report[31] report provide a monthly rundown on the causes and amount of uplift. Other reports are covered in the NYISO's responses to Transparency question 2, below.

The NYISO continually seeks opportunities to enhance its information reporting to improve transparency and enhance understanding of market outcomes by all interested parties, while maintaining the confidentiality of commercially sensitive information. The push towards increased transparency is both for publicly available data and for individual stakeholder data.

For example, the NYISO's 2015 projects included the ICAP Reference System Phase 2 project that streamlined the data collection process and provided increased transparency to stakeholders of the Capacity Market references. The NYISO also completed a Public Website Renewables Page project that developed a new page on the NYISO public website where renewable energy data is displayed, showing current activity and trends of renewable energy production and provides historical data.

[30] The Market Operations Report is presented at each monthly Business Issues Committee meeting. The January 2016 report can be found at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2016-01-13/Market%20Operations%20Report_%20BIC_01%2013%2016.pdf

[31] The Operations Performance Metrics Monthly Report is presented at each monthly Management Committee meeting. The January 2016 report can be found at: http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2016-01-27/Agenda%2003_Operations_Report.pdf

The NYISO has additional efforts planned in 2016 to increase transparency. The Settlement Sub Accounts project is intended to provide more transparency in the settlement data visible to Financially Responsible Parties. This project will provide additional reporting by allowing accounts to be split into multiple sub accounts, down to a bus level of granularity.

The NYISO is currently soliciting market participant feedback to better understand areas of opportunity for further improving data transparency. If opportunities are identified, it is expected that this effort will be prioritized to be worked on in 2017 by the NYISO's Market Participants.

Commission Question(s)

2. Please describe how and the degree to which the RTO/ISO reports the specific reasons for uplift and operator actions. Please also respond to the following:

    a. Are there particular uplift or operator action categories that could be refined or disaggregated to improve transparency about the underlying reasons for uplift? If so, please describe.
    b. Please also describe the tradeoffs involved in refining uplift categories.
    c. Calpine recommends that RTOs/ISOs report the hourly MW and the duration of the uneconomic dispatch each time a resource is committed out-of-market. Please report on whether sharing each element (hourly MW and duration of uneconomic dispatch, to the extent known) is feasible shortly after uneconomic unit commitments are made; and if it is not feasible, please explain the existing barriers.

NYISO Response

The NYISO reports on the specific reasons for uplift and operation actions in multiple ways with different levels granularity and analysis. The NYISO posts operational announcements including operator initiated out-of-market actions as well as other operating modes (ex. large event reserve pickups). Each items is time stamped and, for out-of-market actions (including DARU, SRE and OOM actions) includes the unit(s) involved, the level of individual unit commitment, and the reason for the commitment. The posting also includes a reference to the relevant Application of NYSRC Reliability Rule ("ARR") number, if applicable.[32]

The Operations Performance Metrics Monthly Report that is presented at the NYISO's Management Committee meetings contain the following information:

- monthly total statewide uplift costs and the monthly rate (stated in $ per MWh) associated therewith;
- the categorization of statewide uplift costs as balancing congestion residual costs, which result from differences between the Day-Ahead and Real-Time Markets, or make-whole payments to supply resources;
- detailed breakdowns of the balancing congestion residual component to provide categorization of such costs on a monthly and daily basis, including a root cause analysis to identify the underlying reason for the congestion residuals. Causes that are identified in the monthly report include unscheduled transmission outages, derates to the transfer limits of internal or external interfaces and increases to unscheduled clockwise loopflow around Lake Erie; and
- additional detail and categorization of monthly and daily make-whole payments to supply resources identifying the statewide and local allocation of such costs, as well as detailed regional information regarding the Generators committed out-of-market pursuant to the NYISO's Day-Ahead Reliability Unit ("DARU") and Supplemental Resource Evaluation ("SRE") commitment processes and the total hours each month during which such units were committed pursuant to DARU and SRE procedures.

In addition to the announcements and reports described above, the "Value of Markets" page on the NYISO's web site provides information on uplift as a percentage of total monthly energy costs.[33]

[32] List of ARRs posted on NYISO's web site: http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/TO_Application_of_Reliability_Rules.pdf

[33] Link to Value of Markets page on NYISO web site: https://home.nyiso.com/value-of-markets/

Commission Question(s)

3. PJM notes that certain information that is currently considered commercially-sensitive by market participants may not actually be commercially sensitive. Under section 18.17 of its Operating Agreement, PJM can only post non-aggregated commercially-sensitive offer data approximately four months after bid and offer data were submitted and at a locational level no more granular than zonal. Are there any RTO/ISO tariff provisions that restrict the release of uplift category information (location, speed, frequency, or driver) beyond what is needed to protect confidential information?

NYISO Response

The NYISO is not aware of any tariff provisions that restrict its release of uplift category information (location, speed, frequency, or driver) beyond what is needed to protect Confidential Information and Protected Information. The NYISO reports on local reliability commitment hours and montly local reliability commitment costs by load zone. However, the NYISO does not publically provide unit specific uplift costs.

Similar to PJM, Section 12.4 of the NYISO OATT treats as confidential "any commercially sensitive information including, without limitation, trade secrets, equipment specific information (e.g., Generator specific data such as heat rates, etc.), and business strategies, affirmatively designated as Confidential Information by its supplier or owner."

The NYISO does not treat any of the information it posts in operational announcements as confidential. The NYISO's operational announcements[34] ordinarily include the reason for each commitment and the level of individual unit commitments.

[34] The NYISO's operational announcements can be found on its website: http://www.nyiso.com/public/markets_operations/market_data/reports_info/index.jsp The user must select the Operational Announcements checkbox to see the reports.

Commission Question(s)

4. How frequently should categories of incurred uplift charges be shared with market participants? How promptly should categories of incurred uplift be shared with market participants?

    a. Is it feasible to disclose uplift or operator actions (including MWs and expected duration), as soon as or shortly after the commitment is made (whether in real-time, if the commitment of uneconomic units is made in real-time, or shortly after the close of the day-ahead market, if the commitment is made day-ahead), while disclosing the reason for that uplift or operator action at a later time once the RTO/ISO has been able to determine the cause? Is releasing this information feasible while protecting confidential information? What protections are required?
    b. If it is feasible to release this information as soon as it is known in real-time, is it also feasible to release the information at a zonal level in real- time? Does reporting real-time zonal information address concerns about protecting confidential information? More specifically, please respond to the following questions:
        i. Is zonal reporting of individual uplift categories feasible and is zonal reporting the appropriate geographic level for uplift reporting? If not, what is the appropriate geographic granularity for reporting uplift categories?
        ii. Can zonal reporting of each uplift category be accomplished without revealing proprietary information?
        iii. Are there any uplift categories for which zonal reporting would not send a sufficiently granular signal? (For example, is zonal reporting sufficiently granular for uplift related to local voltage support?)

NYISO Response

The NYISO currently releases the costs and categories of incurred uplift charges monthly in the NYISO's operations performance metrics reports. As covered in the NYISO's response to Transparency question 2(a)-(c) above, the NYISO also posts information on operator actions shortly after out-of-market actions are taken. The aggregated dollar costs of uplift are available to stakeholders on a daily basis though the daily reconciliation reports. Disclosing the costs of uplift more frequently than daily might risk releasing generator-specific confidential information because in some hours only one generator is the subject of an out-of-market action that generates uplift.

Uplift, generated from the payment of Bid Production Cost Guarantees (BPCGs), is a daily payment. BPCGs are calculated over the course of 24 hours. Hours in which profits are made offset hours in which the unit incurs a loss. It is not possible to accurately report on BPCG uplift on a more frequent basis than daily.

Zonal reporting is feasible in some limited instances but not in others because some local reliability commitment impact so few generators that disclosing the information would release confidential data. The NYISO has not identified any areas where information is insufficiently granular.

Commission Question(s)

4. How frequently should categories of incurred uplift charges be shared with market participants? How promptly should categories of incurred uplift be shared with market participants?

    c. PSEG Companies recommend that RTOs/ISOs never provide unit-specific information about bidding levels, but instead provide uplift cost information categories that are both narrow enough to be useful and broad enough that individual unit profiles cannot be discerned.[35] To what degree is that principle (adjusting the dissemination of uplift information, as needed, to protect confidential information), one which can be applied in real-time or immediately after the close of a market in order to adjust regular reporting requirements?

NYISO Response

The releasing of uplift cost information in real time does not obviate the concerns about the release of Confidential Information because out-of-market commitments can be infrequent enough that the uplift payment could be tied to a specific generator and reveal its costs. With the MW commitment (provided by the operational announcements) there would be enough

[35] PSEG Companies Comments at 10; *see also* Western Power Trading Forum Comments at 8.

information to calculate marginal costs in certain circumstances, which are commercially sensitive and considered Confidential Information under the NYISO's tariffs.[36]

Commission Question(s)

5. PSEG Companies suggest that NYISO's specific uplift reporting practice may represent a "best practice." This reporting includes: (1) all operator-initiated out-of-market actions in the daily operational announcements that are released as the actions are taken; (2) which units are involved; (3) the level of the individual unit commitment; and (4) the time of the actions. Are the speed, level of unit-specific detail (excluding payment information), and geographic granularity of this uplift reporting simultaneously feasible in other RTOs/ISOs? If not, to what degree could the RTO/ISO improve the speed and granularity of its out-of-market commitment and operator action reporting to approach NYISO's level of transparency in reporting real-time uplift?

NYISO Response

The NYISO appreciates the PSEG Companies identifying the NYISO uplift reporting practice as a "best practice."

Commission Question(s)

6. Direct Energy contends that unexpected operator actions, when needed, should be made pursuant to predictable protocols that are known to market participants. Calpine argues that models or algorithms used to determine operator actions, as well as any non-market changes to model inputs or results, should be transparent and publicly disclosed.

    a. Please explain the RTO's/ISO's process for releasing changes to market models (such as revising assumptions about constraints or adding new closed-loop interfaces). What factors does the RTO/ISO consider when determining whether or not to release information about changes to market model inputs?
    b. Does the RTO/ISO release this information to all market participants?
    c. What limits are necessary prior to disseminating changes to the RTO/ISO market model?

[36] The LBMP at the generator's location plus the uplift paid would give a good indication of the generator's operating costs at a given level of dispatch.

NYISO Response

The NYISO works with its Market Participants via its stakeholder meetings when it plans to make significant changes to its market models. During these meetings the NYISO identifies the drivers for the change, the expected market impacts and the timeframe for implementing the change.

The NYISO has found this process beneficial. Stakeholders have helped improve upon the NYISO's proposed market model assumptions. For example, when the NYISO rolled out how it intended to implement the Lake Erie Circulation adjustment Market Participant feedback helped ensure that the adjustments NYISO implemented are transparent to the marketplace.

The corrected table below captures operators actions or algorithms to model factors that could affect the scheduling of resources.

Operator Action	**a) Process to Release Change**	**b) Released to all MPs**	**c) Necessary Limits**
DARUs	Posted to operational announcements, see Day Ahead Scheduling manual[37]	Yes	Some DARU information is posted earlier
SREs	Posted to operational announcements	Yes	None
OOMs	The NYISO posts all Transmission Owner requested OOM reliability commitments and all NYISO OOM reliability	No: confidential generator information	None

[37] Day-Ahead Scheduling Manual section 4.2.6 Day-Ahead Reliability Unit (DARU) Commitment, Transmission owner requests for DARUs: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/dayahd_schd_mnl.pdf

	commitments of generators that are not GTs.		
TSAs	Posted to NYISO Main page	Yes	None
PAR optimization	Posted to PAR Schedules and PAR Flows	Yes	None
TLRs	Manual override of transactions	No: only MP submitting the transaction can see the change	None
Circulation – Unscheduled Power Flow	Posted to Power Grid Data Interface Pricing[38]	Yes	Typically done weekly with ability to update as needed
Central East Capacitors for DAM	Posted with DAM Scheduled outages	Yes	None
Maintenance contingencies	Posted as part of active constraints if binding	Yes	None
Transaction cuts	Manual override of transactions	No: only MP submitting the transaction can see the change	None
Reserve pick ups	Posted to operational announcements	Yes	None
System State changes	Posted to operational announcements	Yes	None
SCR activation	Posted to operational announcements	Yes	None

[38] Link to Interface Pricing Expected Unscheduled Power Flows: http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/DAM_UPF_Web_Posting.pdf

III. CONCLUSION

The NYISO supports the Commission's vision for proper price formation and increased transparency in wholesale energy and ancillary services markets. The NYISO has designed it markets in a manner that is consistent with this vision and continually reviews its markets to identify opportunities for enhancements to improve market efficiency and transparency of market outcomes. NYISO respectfully requests that the Commission consider the responses it provided in this corrected Report in determining what, if any, actions it should take in this proceeding.

Respectfully submitted,

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