UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

REPORT OF ISO NEW ENGLAND INC.

As directed by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in its November 20, 2015 Order Directing Reports,[1] ISO New England Inc. ("ISO-NE" or the "ISO") provides its responses to the Commission's specific questions regarding various price formation issues. For context, the Commission's questions are also included below (in italics, with footnotes omitted).

In sum, ISO-NE fully supports sound improvements to energy pricing, and agrees with the broad market design principle that the costs of operating an efficient, reliable power system should be reflected in transparently-priced products and services. Indeed, ISO-NE and its stakeholders have made significant strides in improving price formation in the New England markets, through a new methodology for the dispatch and pricing of fast-start resources, enhanced modeling of constraints, priced locational reserve products, and the adoption of look-ahead modeling tools. Together, the steady progression of these and other market design improvements results in total uplift that amounts to only one to two percent of the total energy market value in New England.

The uplift that remains today is, in large part, attributable to generators' technological characteristics – most notably, the inherent "lumpiness" and inflexibilities of current generation

[1] 153 FERC ¶ 61,221.

technologies – that limit certain generators' ability to promptly shut down when their energy is no longer needed, or require them to start up and produce energy before it is actually needed. As explained in this report, although such units may receive uplift from time to time, their operation and dispatch is still the least-cost, most economically efficient way to satisfy energy demand while respecting the system's transmission security constraints.

In fact, the level of uplift that remains is, to a large degree, intrinsic to the operation of an efficient, least-cost power system in which energy is priced on the basis of marginal cost – a fundamental economic principle that forms the basis for Locational Marginal Pricing generally. New initiatives to eliminate remaining uplift may not be practical, or may entail unforeseen consequences at the expense of the market's overall performance.

The allocation of uplift costs also raises challenging issues. When the root cause of uplift is the inherent "lumpiness" and inflexibility of generators, it is generally difficult to identify a participant action that could be determined to have "caused" the uplift. In these cases, it may be that uplift should be allocated based on the Commission's beneficiary-pays principles, as the consumer is the ultimate beneficiary when the power system is operated in the least-cost, most efficient manner.

In conclusion, as highlighted in ISO-NE's answers below, many of the questions posed in the Commission's November 20th Order involve complex, technical issues that may not have clear answers. ISO-NE appreciates the Commission's deliberative approach to these challenging issues.

A. Pricing of Fast-Start Resources

(¶ 29) *Little consensus exists on the best approach to pricing block-loaded fast-start resources. Also, not all RTOs/ISOs explained how they weighed the tradeoffs involved and the costs and benefits associated with their current fast-start pricing logic. In addition, the operating practices of each RTO's/ISO's fast-start pricing logic are not necessarily detailed fully in tariffs and manuals. Recognizing that there may be no single best practice for dispatching and pricing these resources, we seek further information regarding the different fast-start pricing approaches and associated tradeoffs. As such, we direct each RTO/ISO to submit information related to its fast-start pricing practices, as discussed below.*

On September 24, 2015, ISO-NE filed (in Docket No. ER15-2716-000) significant changes to the ISO New England Transmission, Markets and Services Tariff (the "Tariff") related to resource dispatch, pricing, and compensation. These changes were broadly supported by stakeholders, and were accepted by the Commission on October 19, 2015 with an effective date of March 31, 2017. Excepted as noted below, the information provided throughout these answers is based on the improved provisions that are scheduled to become effective in 2017.

ISO-NE agrees with the Commission that there is no single "best" method for setting prices when fast-start resources are deployed – whether from the standpoint of economic theory, or as an unambiguous, state-of-the-art "best practice." Accordingly, while the changes made by ISO-NE help to reduce total out-of-market payments and better reflect the costs of fast-start resource deployments in energy and reserve market prices, neither they nor any other methodology can, in principle or in practice, completely eliminate out-of-market payments to fast-start resources. More specifically, although fast-start pricing improvements can shift a greater share of resources' total compensation into the LMP-based energy and reserves markets, the potential for out-of-market payments cannot be eliminated completely given the "lumpy" nature of fast-start generators. These out-of-market payments remain necessary, in some conditions, to ensure that units are properly compensated and have proper incentives to follow dispatch instructions.

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?*

Under the revised methodology accepted by the Commission and scheduled to be effective beginning March 31, 2017, the fast-start pricing logic will apply throughout a fast-start resource's actual run time, as described in more detail in response to Question A.1.c below.

   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?*

In New England, the fast-start pricing logic applies to both the dispatch and pricing processes, though there are differences in how it applies in each process. This is described in more detail in response to Question A.1.c below. Technically, dispatch and pricing are separate optimization processes, occurring in that order. In practice, however, they are executed close to simultaneously.

   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.*

Under the Commission-approved revised method, the *dispatch* solution satisfies a fast-start resource's offered minimum output level throughout its run time, including the initial commitment interval. The real-time *pricing* process, however, relaxes a pool-committed fast-start resource's minimum output level to zero throughout its run time. In other words, under the revised methodology, the dispatch process will not relax the minimum output level in any interval, while the pricing process will relax the minimum output level in all intervals. The rationale for this approach is addressed in response to Question 1.e, below.

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?*

As described above in response to Question A.1.c, under the revised methodology, the dispatch solution is calculated to satisfy a fast-start resource's offered minimum output level throughout its run time. This is true regardless of whether a fast-start resource sets 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.*

Under the revised method, the pricing (but not dispatch) process will relax a pool-committed fast-start resource's minimum output to zero for the duration of the resource's run time (not just during the initial commitment interval, as occurs in New England's system presently). This new method will allow the pricing algorithm to treat the fast-start unit as marginal, and therefore able to set the LMP, under a broader range of dispatch conditions. As a result, a fast-start resource will be able to set the LMP much more frequently than occurs today – generally, when its operation is economically useful to the system and it is the highest-cost resource operating at the time. The costs incurred to operate these resources will therefore be more frequently reflected in the real-time energy and reserve market prices, improving performance incentives for all resources.

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.*

As stated above, on September 24, 2015, ISO-NE filed significant Tariff changes related to resource dispatch, pricing, and compensation aimed at improving real-time price formation when fast-start resources are deployed. That filing provides a detailed discussion of the changes and their expected effects on uplift (also referred to as Net Commitment Period Compensation or NCPC in New England), and is incorporated herein by reference.

Regarding uplift, ISO-NE conducted a market simulation analysis that suggested that the specific changes becoming effective in 2017 will reduce total real-time uplift payments to both fast-start resources and non-fast-start resources in the New England system. Based on that analysis, the estimated net reduction in total real-time out-of-market payments in 2014 that would have resulted if the improvements had been in place for 2014 (after accounting for other rules implemented since that time) is approximately $14 million. As a reference point, the actual value of total real-time uplift during 2014 was $93.3 million.

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?*

In New England, the term "fast-start" generally describes resources that can be started in thirty minutes or less, have a minimum run time of one hour or less, and have a minimum down time of one hour or less. Specifically, fast-start resources include: Fast Start Generators, fast-start Flexible DNE Dispatchable Generators, fast-start Dispatchable Asset Related Demand resources, and Fast Start Demand Response Resources.[2]

With respect to the first two types, Fast Start Generators and Flexible DNE Dispatchable Generators,[3] the Tariff does not restrict participation to a specific set of physical generation technologies *per se*. Rather, a generating unit is treated as "fast start" based on its capability to operate consistent with the Tariff's requirements, as summarized above. Presently, the Fast Start Generators in the New England system are largely comprised of combustion turbines, internal-combustion (non-turbine) units, pondage-based hydroelectric generators, and pumped-storage hydroelectric generators. Flexible DNE Dispatchable Generators are a new resource type currently being implemented to dispatch certain types of intermittent generating resources, and (at this time) are anticipated to be comprised primarily of non-pondage hydroelectric and wind resources.

The revised fast-start pricing method will also apply to Dispatchable Asset Related Demand resources that meet the same general criteria as fast-start resources (that is, can be started in thirty minutes or less and have a minimum run time of one hour or less). This treatment is appropriate because such assets can reduce real-time energy demand, participate directly in the real-time energy markets today by submitting price-based bids to reduce demand in real-time, and be dispatched in real-time on the same short timeframes as other fast-start resources.

The revised fast-start pricing method will not apply at this time to Fast Start Demand Response Resources. Completion of another ongoing project – the full integration of demand

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[2] *See* Tariff Section I.2.2. Each of these resource types may have additional requirements specified in the Tariff.

[3] The term "Flexible DNE Dispatchable Generator" will become effective in the Tariff in April 2016 pursuant to *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,065 (July 23, 2015).

response resources into New England's wholesale energy markets and reserve markets – is a technical prerequisite for applying the new pricing method to these resources. That project will implement the more fundamental changes necessary to dispatch and permit demand response resources to set price in the real-time energy market. The Commission has accepted Tariff changes related to that project,[4] but implementation was delayed in light of subsequent court decisions.[5] Once the full integration of demand response resources into the energy and reserve markets is implemented, the improved pricing treatment can be extended to Fast Start Demand Response Resources. The full integration changes are currently expected to be completed in 2018.

Under the new provisions, in New England, fast-start resources cannot elect to be excluded from the fast-start pricing provisions, except by self-committing. The fast-start pricing logic applies only to pool-committed fast-start resources.[6] This is economically appropriate. Under ISO-NE's energy market design, self-committing a resource indicates that the resource seeks to operate as a price-taker in the energy market for quantities up to its offered minimum output level. Accordingly, it would not be appropriate to extend price-*setting* logic to a resource that seeks to operate as a price-*taking* supplier of its specified minimum output.

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.

A resource's Start-Up Fee is a marginal cost before the resource is committed. After the resource is committed, the Start-Up Fee is a sunk cost. Because the start-up decision is

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[4] *See ISO New England Inc. and New England Power Pool Participants Committee*, Order Accepting Tariff Revisions, 150 FERC ¶ 61,007 (issued January 9, 2015).

[5] *See* F.E.R.C. v. Electric Power Supply Ass'n, 136 S.Ct. 760 (2016).

[6] As a general matter, fast-start resources can be either pool-committed or self-committed. In simple terms, with a pool-committed resource, the initial decision to start the resource is made by ISO-NE. With a self-committed resource, the initial decision to start the resource is made by the market participant.

instantaneous, a practical issue arises regarding the period of time over which the start-up cost should be amortized. Economic theory does not provide a precise answer, but provides a partial guide: because the start-up costs are marginal when the resource is committed, there is a conceptual rationale for incorporating them into prices at the time the resource is started. This serves as a price signal to the markets about the costs of the marginal action being undertaken to operate the power system economically in real time.

The revised method recently accepted by the Commission will amortize a fast-start resource's Start-Up Fee over the resource's minimum run time. This means that a fast-start resource's Start-Up Fee will be amortized over a resource-specific time period ranging from a minimum of fifteen minutes to a maximum of one hour (because one hour is the maximum value of the minimum run time allowed for a fast-start resource in the Tariff).

With this Start-Up Fee amortization approach, a resource that is economically committed and dispatched to its maximum output level for the duration of its minimum run time will not require an uplift payment to cover the costs it incurs to start, as its start-up costs will be covered by the market price for energy. Further, by setting the Start-Up Fee amortization period based on the (resource-specific) minimum run time, the revised approach avoids creating situations in which a marginal fast-start resource would recover more than the full amount of its Start-Up Fee if it continues to operate economically after the end of its minimum run time.

The treatment of the No-Load fee is similar, but not exactly the same. While the Start-Up Fee is a fixed dollar amount incurred when the resource starts to operate, the No-Load Fee is a continuous rate when the resource operates. That is, if it is economical to continue operating a fast-start resource after its minimum run time, the resource continues to incur its no-load cost.

(This difference between the two is exemplified by the fact that the Start-Up Fee is denominated in dollars per start, while the No-Load Fee is denominated in dollars per hour.)

In the pricing process, under the revised method, the No-Load Fee of a fast-start resource will be amortized over the resource's maximum output and then added to its incremental energy offer price throughout the resource's actual run time. The Start-Up Fee of a fast-start resource will be amortized over the resource's maximum output and the resource's minimum run time (instead of over one hour, as is the current practice), and the amortized value will be added to the resource's incremental energy offer price throughout the resource's minimum run time. Thus, under the revised method, a fast-start resource's adjusted incremental energy offer price will be the sum of its incremental energy offer and its amortized no-load value and, during its minimum run time period, its amortized start-up value.

The treatment of the Start-Up Fee and No-Load Fee in fast-start pricing is discussed further in Attachment A of ISO-NE's September 24, 2015 filing. Attachment A includes detailed numerical examples.

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.

ISO-NE assumes that "offline" refers to a resource that has not been committed (*i.e.*, not instructed to start). Under both the current rules and the revised method scheduled to become effective in 2017, fast-start resources that have not been committed (whether block-loaded or otherwise) cannot set the LMP. In general, if a resource has not yet been committed by ISO-NE's dispatch and commitment software systems, there is no simple means to determine whether deploying such a resource represents the marginal action the system would undertake in real-time to satisfy incremental energy demand at each node.

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.*

ISO-NE's Tariff does not define "block-loaded;" therefore, the table below relies on the definition provided by the Commission in the Order Directing Reports ("[a] block-loaded resource is a resource whose economic minimum operating limit is equal to its economic maximum output").[7] The data in the table below is presented separately for hydroelectric and non-hydroelectric resources, because a materially different proportion of each type is block-loaded in the New England system. (Note that seven pumped storage resources are included in the "Hydro Generators" category.)

Fast-Start Resources in New England
Block-loaded defined as EcoMin equal to EcoMax

Number of Generators	Block-Loaded FS Resources	Non-Block-Loaded FS Resources	Total FS Resources	% of FS Resources Block-Loaded	% of FS Resources Non-Block-Loaded
Non-Hydro Generators	57	38	95	60%	40%
Hydro Generators	1	28	29	3%	97%
Total	58	66	124	47%	53%
Summer Claimed Capability MW					
Non-Hydro SCC MW	1626	987	2613	62%	38%
Hydro SCC MW	5	2636	2641	0%	100%
Total	1631	3624	5255	31%	69%

Some fast-start resources in New England have a very small dispatchable range, and so do not meet the strict definition of "block-loaded" provided by the Commission. However, as it may be useful to consider these resources "block-loaded" for purposes of considering the fast-start pricing issues raised by the Commission, they are included in the table below for

[7] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221, n.9. (2015).

comparison. Specifically, the table below presents the data for fast-start resources in New England that have an economic minimum limit that is greater than or equal to 90% of its economic maximum output. Using this alternative definition of "block-loaded" has a relatively minor impact on the results.

Fast-Start Resources in New England

Block-loaded defined as EcoMin greater than or equal to 90% of EcoMax

Number of Generators	Block-Loaded FS Resources	Non-Block-Loaded FS Resources	Total FS Resources	% of FS Resources Block-Loaded	% of FS Resources Non-Block-Loaded
Non-Hydro Generators	64	31	95	67%	33%
Hydro Generators	4	25	29	14%	86%
Total	68	56	124	55%	45%
Summer Claimed Capability MW					
Non-Hydro MW	1673	940	2613	64%	36%
Hydro MW	104	2538	2641	4%	96%
Total	1777	3478	5255	34%	66%

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.*

The answer to this question is different under the rules currently in effect in New England and the revisions scheduled to take effect in 2017. Under the rules currently in effect, the dispatch system relaxes a fast-start resource's minimum output level to zero MW during the initial commitment interval. In other words, for the initial commitment interval only, the dispatch optimization treats the fast-start resource as if it were fully dispatchable between zero megawatts and the resource's maximum output level, regardless of the minimum output value submitted in its energy supply offer parameter. Because of this, it is possible that the dispatch system will produce a solution that specifies an output level from the fast-start resource that is greater than zero and less than the resource's minimum output level.

This dispatch solution, however, does not currently govern the electronic dispatch signal actually sent to a fast-start resource. To avoid sending infeasible dispatch instructions, in these situations ISO-NE's real-time systems have additional logic to correct the dispatch instruction sent to a fast-start resource. The corrected dispatch instruction satisfies the resource's offered minimum output level. In other words, even though the economic dispatch solution may call for, say, 30 MW from a fast-start resource at the time of its start-up instruction, if the resource's offered minimum output level is 50 MW, the dispatch instruction electronically sent to the resource will be 50 MW, not 30 MW. In this event, the total generation dispatched in the system will be 20 MW too high, relative to total projected load.

While this problem only exists during the relatively short initial commitment interval, it nonetheless can be economically inefficient. In practice, any over-generation resulting from the electronic dispatch of fast-start resources to output levels in excess of those calculated in the economic dispatch solution will typically be offset by other generators that have Automatic Generation Control and are providing Regulation service at the time. From an economic perspective, this is often not a least-cost outcome. It would typically be more efficient if the dispatch process did not result in total generation instructions in excess of total projected load in the first place.

ISO-NE has not conducted a study of how frequently the electronic dispatch correction process described above leads to excess generation and additional "downward" regulation service during fast-start resources' initial commitment intervals. Such a study would not be simple to conduct, as the problem is not always manifest in every initial commitment interval (it depends, among other things, on the exact duration between a resource's initial commitment and its synchronization to the power system in each instance). ISO-NE does not believe it would be productive to undertake such a retrospective analysis of this phenomenon in the New England system at this time, inasmuch as the new fast-start pricing enhancements recently approved by the Commission effectively eliminate this problem. These enhancements are discussed next in response to Question A.5.b.

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.*

Under the revised method that is scheduled to become effective in 2017, the commitment and dispatch process will not relax a fast-start resource's offered minimum output level during any portion of its run time, including the initial commitment interval. As a consequence, and in conjunction with the opportunity-cost treatment described next, the potential over-generation problem will no longer present a material concern when a fast-start resource is initially committed. The revised method thereby helps resolve the potential inefficiencies associated with relying on generators on Automatic Generation Control to provide frequency "regulation down" service to counterbalance the potential over-generation when fast-start resources are started today.

Because a fast-start resource's minimum output level is not relaxed in the dispatch process, but will be relaxed in the pricing process (under the revised method scheduled to become effective in 2017), some resources could face lost-opportunity costs. More specifically, if a fast-start resource is dispatched to its minimum output level, and this minimum output level exceeds the additional output required to meet demand, then the dispatch solution must also simultaneously re-dispatch other online resources. In this case, the system's dispatch solution may balance total supply and demand by re-dispatching one or more lower-cost online resources to an output level that is less than its profit-maximizing output level when the fast-start resource sets the LMP. In this situation, the re-dispatched resource incurs a lost-opportunity cost by following its dispatch as instructed.

Unless this opportunity cost is properly addressed by the market design, an affected resource may perceive a financial opportunity to increase its profit by increasing its real-time output above its dispatch instruction. This is not only economically inefficient – because generators may find it profitable to no longer execute their part of the least-cost dispatch for the power system – it can result in an imbalance of power supply and demand and, over time, undermine the ability and confidence of system operators to assure reliable system operation.

To address this problem, under the revised rules, certain re-dispatched resources in these specific circumstances will be compensated for their lost-opportunity costs. This will eliminate the potential financial incentive for a resource to not follow its dispatch instruction that may otherwise arise when a "lumpy" fast-start resource sets the real-time LMP.

Another potential approach would be to impose tariff-based penalties on resources that do not follow real-time dispatch instructions, instead of making the payments for lost-opportunity costs. However, the penalty approach can have other, adverse incentive effects that could undermine resource flexibility and system operational capabilities. Specifically, if there are significant penalties for deviations from dispatch instructions, then a resource owner may find it profitable to minimize its penalty exposure by either: (1) self-scheduling its output more frequently, so that it receives fewer dispatch instructions to change output; or (2) increasing its minimum output level over time, so that ISO-NE's dispatch system does not dispatch that owner's resource down when a "lumpy" fast-start resource may be started and set price – which increases the owner's profit by avoiding its *de facto* lost opportunity cost. These behaviors are plainly inefficient, may reduce operational flexibility, and over time the reduced flexibility may increase the cost of operating the power system.

At bottom, ISO-NE concluded that implementing express penalties for not following dispatch instructions is less economic, less efficient, and poses more potential problems than simply removing the incentive to deviate from dispatch instructions in the first instance. For these reasons, ISO-NE addresses these concerns not through administrative penalties, but instead – in the limited circumstances when necessary – via lost-opportunity cost payments.

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.

The improved methodology that will become effective in 2017 in New England is being implemented in the real-time energy and reserves markets only. Implementation in the day-ahead market would have a far smaller beneficial impact than implementation in the real-time markets.

In New England, most fast-start resources do not clear in the day-ahead market. This is especially true for the system's fossil-fuel fast-start resources, which are a combination of internal-combustion units and simple-cycle peaking units. Resources of these types operate on expensive fuels (primarily distillates), and have sufficiently high operating costs that they are generally uncompetitive – and thus infrequently clear – in the day-ahead market. These high-cost resources primarily operate in response to unanticipated real-time system conditions – thus the key benefits of fast-start pricing reforms should result from implementation in the real-time markets, rather than the day-ahead market.

Focusing implementation on the real-time markets reduces complexity and allows for quicker implementation of fast-start pricing improvements in the market where it will provide the most benefit.

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.

Under the revised method that is scheduled to become effective in 2017, fast-start resources will be able to set the LMP whether or not they are block-loaded.

Fast-start resources are generally inflexible once they are started, meaning that they typically operate inefficiently at less than their maximum output, or may not be able to physically operate much below their maximum output. As a consequence, the energy supply offer parameters of these resources may stipulate that they be dispatched either to zero output, or to a minimum level that is at (or close to) their maximum output, and not in between.

Because they must be dispatched to a minimum output that is at, or close to, their maximum output, when fast-start resources are initially committed they frequently must add more power to the system than the incremental demand for power (which, in turn, requires other, online resources to be concurrently dispatched down slightly). In these situations, conventional real-time pricing algorithms would generally determine that, once operating, the fast-start resource's dispatch would not change if there is a perturbation in demand – and the ability to change is a requisite condition for a generator's supply offer to set the LMP. From a price formation standpoint, in these conditions the energy market's price signal fails to convey the costs of operating the fast-start resource – costs that an ISO must incur to operate the power system reliably and economically.

These price formation issues are not specific to whether or not fast-start resources are block-loaded. Rather, the problem described above is related to the frequency with which resources are economically dispatched to their minimum output levels during their run times. Regardless of whether or not they are block-loaded, in such instances the foregoing price formation problems would arise. Moreover, in New England, most fast-start resources have a minimum operating limit that is below their maximum output; *see* the tables in response to Question A.4, above.

For these reasons, ISO-NE concluded that restricting application of improved fast-start pricing methods to block-loaded resources would poorly resolve the price formation problems that motivated these enhancements in the first place. Moreover, applying different pricing treatments based on whether a resource is exactly block-loaded, or using some arbitrary threshold to define 'nearly' block-loaded, could provide perverse incentives for resource owners to make their resources even less flexible in the future in order to become eligible for different pricing rules.

B. Commitment to Manage Multiple Contingencies

(¶ 43) While commenters generally agree that RTOs/ISOs should and often do include multiple contingencies in the market model where practical, it remains unclear to what extent in practice each RTO/ISO incorporates multiple contingencies in its day-ahead and real-time market. Moreover, it remains unclear how units are committed in the day-ahead and real-time market to address multiple contingencies and what proportion of the revenue these units receive through uplift payments rather than payments for energy and ancillary services. As such, we direct each RTO/ISO to submit information related to its commitments to manage multiple contingencies, as discussed below.

Before addressing the Commission's specific questions on this topic, ISO-NE provides some background information about how multiple contingencies are addressed in New England.

The New England wholesale energy and reserve markets are cleared through a security-constrained economic commitment and dispatch process. This process employs ISO-NE's Energy Management System ("EMS") and network model of current and expected system conditions. The network model includes, among other things, the system's transmission topology, facility outages, bus-level energy injection and withdrawals, and energy interchange with neighboring Balancing Authority areas.

The network model also incorporates system operating limits for both transmission system elements and transmission interfaces.[8] These limits specify critical system operating parameters that must be honored in a reliable power system, including transmission thermal limits, voltage limits, and stability limits. These limits are used to determine a large set of constraints that must be satisfied by both the day-ahead market solution and the real-time market (dispatch) solution.

In addition, the market solution is tested against an extensive set of additional constraints that model system *contingencies* – the sudden loss of a transmission system element or a generation source. In essence, testing the market solution against the contingency constraints corresponds to checking thousands (literally) of "what if" scenarios in which the sudden loss of a transmission system element or generation source is assumed to occur, and the remaining system elements are *then* evaluated for violations of system operating limits. If a limit would not be satisfied post-contingency (within a limit-specific timeframe), the market clearing algorithm (whether day-ahead or real-time) will compute a different pre-contingency commitment and dispatch solution to ensure the relevant post-contingency constraint will be satisfied, and do so in

[8] An interface is a set of specific transmission system elements.

the most economical way. In essence, this process comprises much of the "security constrained" aspect of the markets' security-constrained economic commitment and dispatch process.

Because of the mathematical and physical complexity of how power responds to disturbances on an alternating current power system (particularly with respect to voltage and stability), ISO-NE employs a number of sophisticated software tools, some running concurrently or on different timeframes, in order to evaluate whether post-contingency conditions on the power system would violate a system operating limit. The studies include: a power system simulator with an off-line network study model for transient stability; a power flow solution (within the EMS) for real-time and near real-time thermal and voltage analysis; and additional dynamic stability and voltage stability analysis tools.[9]

Taken together, the set of constraints analyzed to ensure the transmission security of the power system (in both the day-ahead and real-time timeframes) can be grouped into three categories. These are: (1) "base case" security constraints, which correspond to the system's current or expected (*i.e.*, pre-contingency) state; (2) the "N-1" security constraints, which correspond to limits on *pre*-contingency dispatch solutions in order to assure the power system can be operated within acceptable criteria immediately *after* a single contingency occurs; and (3) the "N-1-1" security constraints, which address multiple contingencies.[10] The "N-1-1" security constraints, which apply to specific transmission interfaces, serve a NERC requirement that *after* a single contingency occurs, the interface return to an "N-1" secure state within 30

[9] The studies used to evaluate contingencies against system operating limits are described further in Section 4.1 of Master/Local Control Center Procedure No. 15 (System Operating Limits Methodology), which is located at http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc15.pdf ("M/LCC 15").

[10] The specific procedures and conditions used to determine which contingencies are modeled are based on criteria of both the North American Electric Reliability Corporation ("NERC") and the Northeast Power Coordinating Council ("NPCC"). *See* the ISO's Operating Procedure 19 (Transmission Operations), which is located at http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op19/op19_rto_final.pdf ("OP 19").

minutes or less. These “N-1-1” constraints restrict the set of commitment and dispatch solutions in the markets’ economic optimization processes.

We interpret the Commission’s questions in this section of the November 20 Order to refer to this third category of contingencies (N-1-1), and their treatment in the day-ahead and real-time systems.

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.

Because ISO-NE accounts for both single (N-1) and multiple (N-1-1) contingencies explicitly in its security-constrained economic dispatch and commitment systems (in both the day-ahead and real-time markets), energy prices will incorporate the incremental costs of any unit committed to satisfy a contingency constraint if the unit is dispatched between its minimum and maximum operating limits. In such cases, the resource is marginal and therefore its incremental energy offer price determines (in whole or in part) the LMPs.

If the resource is committed to satisfy a contingency constraint and it is dispatched <u>at</u> its minimum operating limit, then it is not a marginal resource; as a result, it does not set LMP and may be paid uplift.[11] In this case, because of the lumpiness (*i.e.*, inflexibility) of its minimum output level and/or minimum startup times, the unit has been committed before the contingency in order to ensure that it is online and available to produce energy quickly if the contingency occurs. However, if satisfying the relevant transmission security constraint does not require the full minimum energy output level offered by the generator, then the generator’s minimum energy output level constrains the least-cost solution to procure more energy from the unit (pre-contingency) than is strictly necessary to satisfy the security constraint.

[11] Exceptions may occur with fast-start resources, as discussed previously (*see* the response to Question A.7, above).

In sum, the inherent inflexibility of generating units' energy output levels and the need to commit the system in a manner that prepares the system for contingencies means that (*i*) a committed unit may not be the marginal resource used to satisfy an increment of energy demand anywhere on the system, because the unit's incremental costs are higher than other available resources' incremental costs; and yet (*ii*) the unit's commitment is nonetheless the least-cost, most economically efficient way to satisfy the system's transmission security constraints.

In total, uplift payments related to protecting the New England transmission system from multiple contingencies constitute about 0.7% of total annual energy market revenue.[12] As discussed in the response to Question B.4 below, these payments will be reduced by a change to the uplift rules that was approved by the Commission on December 23, 2015 in Docket No. ER16-250-000.

ISO-NE continually seeks to identify potential market improvements, and undertakes technical research projects that can improve the efficiency of the real-time and day-ahead security-constrained market solutions. Such improvements may reduce uplift generally, but reducing uplift to resources committed to satisfy (N-1-1) contingency constraints *per se* is not a specific focus of these efforts. Progress in this area entails inherently complex economic, engineering, and software development problems, and further research is necessary before ISO-NE is in a position to put forth any well-developed recommendations, implementation timelines, or cost estimates.

[12] *See* the data provided in response to question 4, below. Total energy revenue for the twelve months ending in September 2015 was $6.325 billion.

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.*

We address this question in two parts. The first part addresses ISO-NE's modeling of both single (N-1) contingency and certain multiple (N-1-1) contingency security constraints in its day-ahead and real-time market solutions.[13] The second part addresses the reserve products used to manage multiple (N-1-1) contingencies.

Determining Constraints

The criteria for determining what constraints are included in the day-ahead and real-time solutions are based on NERC and NPCC standards and are described in detail in the ISO's Master/Local Control Center Procedure 15.[14] In brief, this procedure describes the inputs into the network study model (Section 4) and the methodology for determining system operating limits (Section 5). More specifically:

- Section 5.1 addresses the determination of system operating limits to prevent thermal overloads or cascading thermal overloads. These limits are established after evaluating the system's response to certain contingencies, and include studies of anticipated system conditions, various peak load assumptions, and simulation of Special Protection System actions. Section 5.1 also explains the consideration of enhanced limits, when, for example, a facility limit that is the basis for a System Operating Limit is weather-sensitive.

- Section 5.2 describes the process for developing system operating limits to prevent cascading voltage collapse. This process involves testing contingencies

[13] The network model is the same in both markets, although various parameter values in the EMS, which incorporates the network model, are updated between the day-ahead and real-time timeframes as system conditions evolve during the operating day.

[14] M/LCC 15.

and studying the system under stressed conditions (*e.g.*, high and low load levels at which voltage control problems are typically manifest).

- Section 5.3 describes the development of transient and dynamic stability system operating limits. These limits are determined through testing under a wide range of system conditions, including light load.

Some of these limits (*e.g.,* thermal limits) are determined on a daily basis, and may be updated more frequently than daily, based on system conditions that are evaluated using specialized limit calculation tools. Other limits are modeled with static values that are updated periodically after detailed transmission operational studies are performed that re-validate or update the relevant limiting parameter values.[15]

In clearing the day-ahead and real-time markets, the security-constrained economic commitment and dispatch process tests and satisfies these system operating limits under the base case (pre-contingency) state, single post-contingency states, and multiple (N-1-1) post-contingency states of the power system. The security constraints may be at the level of transmission system interfaces, or at the level of specific transmission system elements, as appropriate to the specific system operating limit. With respect to multiple contingencies, ISO-NE protects all transmission interfaces subject to Interface Reliability Operating Limits at the N-1-1 level.[16]

Notably, solving the security-constrained economic commitment and dispatch problem (whether day-ahead or real-time) to satisfy the N-1-1 security constraints does not mean the system is prepared to withstand the system's two largest contingencies simultaneously. Rather, it means that the commitment and dispatch solution positions the system to be able to restore N-1 security of the relevant transmission interfaces within thirty minutes following the largest

[15] Additional details on contingency analysis procedures are provided in Control Room Operating Procedure CROP.34007, available at http://www.iso-ne.com/participate/rules-procedures/system-operating-procedures.

[16] *See* M/LCC 15 and OP 19.

contingency on the system. This time-dependent aspect of managing multiple contingencies means that satisfying the N-1-1 security constraints is a function of the amount of generation re-dispatch that can be performed within thirty minutes – which leads to the topic of ISO-NE's reserve products.

Reserve Products and Multiple (N-1-1) Contingency Security Constraints

ISO-NE uses both system-level reserve products and locational reserve products to help satisfy single (N-1) contingency and multiple (N-1-1) contingency security constraints. Specifically, the ISO procures its thirty-minute operating reserve products on a locational basis. These locational reserves allow ISO-NE to satisfy, on an *ex ante* basis, the multiple (N-1-1) contingency security constraint for an import-constrained area of the system by procuring locational thirty-minute reserves on the import-side of the area's interface.

For example, if an import-constrained area of the region's power system (like the Northeast Massachusetts/Boston area) experiences the sudden loss of a large generator in real-time, and then power flows into that area at levels that exceed the interface's pre-contingency operating limit, ISO-NE may need to simultaneously reduce the higher power flows across the interface and prepare the system (within thirty minutes) to withstand a second contingency in this area.[17] To achieve these goals, ISO-NE may need to dispatch additional generation *within* the import-constrained area promptly – which it has available in the form of thirty-minute operating reserves in the area.

In the commitment phase of the day-ahead market solution, ISO-NE solves to ensure the projected real-time locational reserve requirements will be satisfied using proxy (N-1-1) interface constraints. In real-time, the actual quantity of locational reserves required in an area is

[17] Post-contingency transmission system operating limits are higher than normal operating limits, so this situation generally does not require emergency actions (*e.g.*, load shedding) to immediately reduce the power flows across the interface into the area.

modeled as a constraint in the dispatch and pricing solutions throughout the operating day. The real-time requirement is a dynamic constraint, inasmuch as the quantity required depends (among other things) on the specific pattern of generation, power flows, and potential contingencies in the relevant areas of the system. These are evaluated, and the locational reserve requirements are recalculated, continuously during the operating day; the recalculated reserve requirements are procured in the real-time market with each dispatch solution. This real-time market (dispatch) solution co-optimizes reserves and energy, so the prices for system-level reserves, locational reserves, and energy are jointly determined every five minutes based on the offer prices of marginal resources providing each of these products.[18]

In addition to the thirty-minute reserve products that are procured (in part) to address multiple (N-1-1) security constraints, ISO-NE also procures ten-minute reserve products. The ten-minute reserve products are not primarily designed to serve the system's multiple (N-1-1) contingency protection needs; rather, they satisfy applicable NERC and NPCC criteria related to managing first-contingency system response requirements (*e.g.*, recovering the system's Area Control Error within the fifteen-minute Disturbance Recovery Period following a NERC-reportable contingency).

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.

It is uncommon for ISO-NE to commit a resource to satisfy an N-1-1 security requirement outside of the security-constrained economic commitment and dispatch process.

[18] The price for a reserve product may be set at a Tariff-specified administrative level (known as a Reserve Constraint Penalty Factor) when a reserve requirement cannot be satisfied. *See* Section III.2.7.A of the Tariff.

ISO-NE estimates that the uplift cost related to “manual” commitments is 7% of real-time second contingency uplift.

When such commitments are made necessary by (*e.g.*) changes in anticipated system conditions after the day-ahead market clears, ISO-NE performs an evaluation to assess whether additional generator commitments may be necessary. Specifically, ISO-NE’s operational procedures require review of the set of generation resources that have cleared the day-ahead market, and an assessment of the need for additional capabilities to satisfy the system’s local second-contingency (N-1-1) protection requirements. If additional generating resources are required and more than one generating unit is able to satisfy the requirement, ISO-NE performs an economic evaluation to determine the least-cost generator than can meet the requirement.[19]

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.

In the ISO Tariff and settlement systems, generating units that are committed to provide multiple (N-1-1) contingency protection are known as Local Second Contingency Protection Resources (“LSCPR”). The following table shows the number of LSCPR commitments made each month for the period October 2014 through September 2015. This includes both resources committed economically within the day-ahead market (but that nonetheless receive uplift due to their operation at minimum output levels, as discussed previously), and resources committed after the day-ahead market process. These data were obtained from the ISO’s day-ahead market clearing process records (units that are committed for LSCPR are noted when the day-ahead

[19] The details are provided in Section 5.7 of SOP-RTMKTS.0050 (Determine Reliability Commitment for Real-Time), available at http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0005.pdf (“SOP-RTMKTS.0050”).

market clearing process is performed), and from a review of ISO operational event logs (for the real-time market). Payments totaled approximately $42 million over this period, and were spread among various system zones as shown in the second portion of the table.

The amount of real-time uplift shown in the penultimate column will decline beginning in February 2016 with the implementation of the changes to uplift rules that were approved by the Commission on December 23, 2015 in Docket No. ER16-250-000. These changes eliminate certain payments made to resources in both day-ahead and real-time for the same second contingency commitment. The exact magnitude of the decline is not known with certainty at this time, due to the recent implementation of this rule change.

Second Contingency Uplift Summary, October 2014 - September 2015				
Number of Commitments*	**Month of Payment**	**For Day-Ahead**	**For Real-Time**	**Total**
35	Oct-14	$5,005,378	$551,515	$5,556,893
134	Nov-14	$2,046,157	$952,987	$2,999,144
24	Dec-14	$12,988	$134,827	$147,815
9	Jan-15	$182,864	$333,175	$516,039
11	Feb-15	$601,101	$263,597	$864,698
329	Mar-15	$1,977,845	$2,896,359	$4,874,204
81	Apr-15	$3,501,565	$3,490,129	$6,991,694
33	May-15	$1,082,674	$921,209	$2,003,883
9	Jun-15	$2,407,270	$2,185,395	$4,592,665
21	Jul-15	$98,004	$114,991	$212,995
28	Aug-15	$487,975	$597,035	$1,085,010
89	Sep-15	$6,607,818	$5,268,373	$11,876,191
803	**Grand Total**	**$24,011,639**	**$17,709,592**	**$41,721,231**

* Unit of measure is "unit days," *i.e.*, one unit flagged on one day, either DA or Post-DA

Reliability Region		**Commitments**	
9001	Maine	117	14.6%
9002	New Hampshire	161	20.0%
9003	Vermont	0	0.0%
9004	Connecticut	3	0.4%
9005	Rhode Island	144	17.9%
9006	SEMA	171	21.3%
9007	WCMA	6	0.7%
9008	NEMABOS	201	25.0%
		803	

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.*

ISO-NE already represents multiple (N-1-1) contingency constraints in the markets' security-constrained economic commitment and dispatch models, and procures locational reserve products to address multiple-contingency security constraints. Price formation issues related to these constraints arise, at a fundamental level, from the "lumpiness" (*i.e.*, inflexibility) of the generation resources that comprise the least-cost means to meet the system's LSCPR requirements. In these situations, a generator may operate at its minimum output level because not all of its energy is needed (pre-contingency), *i.e.*, it is not the marginal unit and accordingly does not set the LMP; nonetheless, its commitment and operation at its minimum output level is the least-cost means to satisfy the system's (N-1-1) security constraints. These units may collect uplift. In total for the year ending September 2015, uplift for multiple contingency protection (LSCPR) amounted to $41.7 million, or approximately 0.7% of the total $6.325 billion value of the energy and reserve markets – clearly a relatively small amount of total revenues.

There are significant technical challenges in developing a viable means to better incorporate LSCPR costs in prices. Accordingly, the ISO assesses a higher priority on other, more promising price formation projects.[20] These include pricing multi-hour ramp constraints in the energy and reserve markets, and reviewing whether the seasonal forward reserve market should be replaced with an enhanced day-ahead energy and reserve market.

[20] *See* ISO-NE's Wholesale Markets Project Plan, which describes the key market initiatives underway and planned for the upcoming three years, at http://www.iso-ne.com/static-assets/documents/2015/02/2015_wholesale_markets_project_plan.pdf.

C. Look-Ahead Modeling

(¶ 48) We seek further information regarding the current state of look-ahead modeling implementation across RTOs/ISOs. Additionally, we seek further information regarding the full range of potential benefits from using look-ahead modeling to make actual commitment, dispatch, and pricing decisions rather than solely as an advisory tool for operators. We appreciate that there may be unintended consequences associated with using look-ahead modeling to make actual commitment, dispatch, and pricing decisions. As such, we direct each RTO/ISO to submit information related to look-ahead modeling, as discussed below.

Before addressing the Commission's specific questions on this topic, we first note that all ISO-NE dispatch and commitment software has look-ahead features, and provide a summary of the principal look-ahead systems used by the ISO for commitment and dispatch.

Reserve Adequacy Analysis

The ISO's Reserve Adequacy Analysis ("RAA") process is performed after the close of the day-ahead re-offer period each day. Its purpose is to ensure there will be sufficient resources to meet the ISO's forecast of energy demand and reserve requirements for each hour of the next operating day.[21] The RAA considers updated resource supply offers, updated external transactions, updated demand bids for Dispatchable Asset Related Demand resources, updated generator outage and availability information, and updated ISO hourly load forecast information.

Because the day-ahead cleared energy demand is nearly equivalent to real-time consumption and, as discussed above, the network model includes the transmission security constraints, it is uncommon for the day-before RAA process to result in a supplemental commitment of generation resources.[22] In 2015, there were no supplemental commitments on 91% of days (excluding commitment decisions in real-time).

[21] In New England, the day-ahead energy market clears to meet bid-in energy demand, not the ISO's forecast of energy demand for the next day.

[22] Average day-ahead cleared physical energy in the peak hours was 100.1% of forecasted load during January 2016 and 99.9% during December. The lowest monthly percentage in 2015 was 97.4%. *See* Slides 3 and 34 of Chief

The RAA may be revised during the operating day if there are significant increases in the ISO's load forecast, or if the system experiences an unanticipated outage of a large generation resource or major transmission system element that requires a re-assessment of the generation plan and possible re-allocation of the committed generation for the balance of the operating day. These intra-day RAA processes employ the ISO's security-constrained commitment optimization tools, and are performed using a "look-ahead" timeframe through the end of the operating day.[23]

Generation Control Application

During the operating day, the Generation Control Application ("GCA") software system optimizes the commitment of fast start and pump-storage hydro units over a rolling "look-ahead" period of up to four hours. Specifically, GCA produces optimized schedules for the startup and shutdown of all fast-start units and pumped-storage hydro units over this look-ahead horizon, at fifteen-minute intervals for the next three hours and thirty-minute intervals for the fourth hour. This look-ahead commitment application runs automatically every quarter hour, and can be executed by system operators on demand at any time. In developing an optimized schedule every fifteen minutes, GCA uses the latest system information, including updated generation supply offers and demand bids (from Dispatchable Asset Related Demand resources), updated external interchange schedules, updated generating resource availability information, updated ISO short-term load forecast information, and the current ramping capability of all generators.

GCA takes into account the physical inter-relationships and constraints between generators and pumps within a pump-storage facility. In its power balance calculations, it also accounts for the startup and shutdown ramping energy patterns of slow-moving generating

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Operating Officer's January 2016 report at http://www.iso-ne.com/static-assets/documents/2016/02/february-2016-coo-report.pdf.

[23] For additional details, *see* SOP-RTMKTS.0050.

resources that are coming on-line or going off-line, as indicated by the current operating plan for all generating resources.

Real-Time Dispatch Tools

The startup and shutdown schedules produced by GCA for fast-start resources are implemented through ISO-NE's real time Unit Dispatch System ("UDS"). UDS calculates the final dispatch instructions for all on-line resources, and sends the final startup and shutdown instructions to fast-start resources. UDS is normally operated with a "look-ahead" target time horizon of fifteen minutes. That is, at the time UDS is executed, it uses ISO-NE's short-term projection of system load and other system state conditions to compute an optimal (security-constrained economic dispatch) solution for all dispatchable resources applicable at a time point approximately fifteen minutes forward.

UDS includes a special mode, termed "contingency dispatch," that is run on demand following major system contingencies; it commits fast-start resources, shuts down online pumping hydro units, and rebalances dispatchable resources with a shorter "look-ahead" target time horizon of ten minutes.

In May, 2016, ISO-NE will incorporate "Do Not Exceed" dispatch rules for intermittent resources into the dispatch process. Pursuant to these rules, ISO-NE will use short-term wind forecasting and contingency modeling to determine limits for automated dispatch of wind and run-of-the-river resources within UDS, using the same "look-ahead" target time horizon of fifteen minutes.

Finally, the newly-implemented Coordinated Transaction Scheduling ("CTS") software uses a separate instance of the GCA software system as part of the interchange optimization process with New York. This software projects New England's external interface LMP at different interchange levels every fifteen minutes with a rolling "look-ahead" horizon of three hours. These projections, along with other New England system information, is provided to the New York Independent System Operator ("NYISO") and incorporated into NYISO's calculations of the optimized external interface schedules for the two regions' primary interface. These optimized schedules are updated every fifteen minutes, with the same rolling look-ahead horizon of three hours forward.

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.*

In November 2015, the ISO implemented its current version of the GCA system. As discussed above, this system produces optimized commitment and decommitment recommendations for both fast-start units and pump-storage hydro resources. In December 2015, ISO-NE implemented the CTS software jointly with NYISO. In May, 2016, the ISO will implement the "Do Not Exceed" changes to the dispatch process to better integrate wind and run-of-the-river resources into the security-constrained economic dispatch system.

ISO-NE expects to continue to enhance its modeling and system optimization tools. For example, by the end of the year, ISO-NE will add functionality to the EMS that enables the inclusion of Dispatchable Asset Related Demand resources' intertemporal constraints, including minimum run times and minimum down time constraints.

ISO-NE has not proposed specific additional look-ahead modeling enhancements at this time. In general, the ISO and its stakeholders capture anticipated system enhancements and market rule change projects, on a multi-year "look ahead" basis, through the ISO's annual Wholesale Markets Project Plan.[24]

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.*

Each of ISO-NE's software programs for dispatch and commitment includes look-ahead modeling of some type. These systems are discussed above and summarized in the table below.

Process	Look ahead modeling?	If yes, advisory?	Time horizon considered by the model?	Look-ahead commitment/ dispatch intervals?	Frequency of execution
Reserve Adequacy Analysis (unit commitment)	Yes	No	24 hours when used the day before the operating day; balance-of-day when used during the operating day	Hourly intervals	After the close of the day-ahead Re-Offer Period; on demand if needed during the operating day
GCA	Yes	Yes	up to 4 hours (adjustable by system operators)	12 x 15-min intervals followed by 2 x 30-min intervals	Every quarter hour, or on demand
Unit Dispatch System (incl. Do Not Exceed dispatch)	Yes (see text)	No	15 minutes (adjustable by system operators)	One 15-minute interval	On demand; approx. every 10 minutes
Contingency Dispatch application	Yes	No	10 minutes, adjustable by the Operator	1x10-minute interval	On demand
CTS	Yes	Yes (see text)	3 hours	12x15-minute interval	Every quarter hour or on demand

[24] http://www.iso-ne.com/static-assets/documents/2015/02/2015_wholesale_markets_project_plan.pdf.

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)?*

See the table above.

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).*

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.*

The RAA and GCA look-ahead unit commitment processes used in New England adopt a multi-period optimization model, which minimizes the overall commitment and production cost over the time intervals considered in the look-ahead horizon (typically 24 and 4 hours, respectively). Future system conditions such as forecast energy demand, reserve requirements, and expected interchange levels are considered in the look-ahead optimization. Inter-temporal constraints, such as units' ramp rates, minimum run times, and minimum down times, capture the system's physical supply change limitations.

When a peak load condition occurs in the future period, the look-ahead optimization may propose a solution that:

- Keeps an "out-of-merit" unit online at one point in time in order to provide energy or reserve needs in future intervals (as shutting down such a unit will prevent it from providing energy or ancillary services in the future interval, due to the unit's minimum down time constraint);

- Defers shut-down of a currently-operating fast-start unit, or recommends starting up a fast-start unit at a specific time point in the future; or

- Ramps (dispatches up) a slow-moving generator that is currently “out-of-merit,” to ensure the resource can supply a high level of power during future intervals to meet the system’s peak power demand that day.

When a low-demand condition occurs in the future period, the look-ahead optimization may propose a solution that:

- Orders a pump-storage unit to commence pumping (inter-temporal economic optimization); or

- Ramps (dispatches down) a slow-moving generator that is currently “in-merit” in order to reach its low operating limit in future intervals, to ensure the system is operated economically on a multi-hour basis (and, if necessary, to prevent entering a minimum generation emergency condition in a future interval).

Under these conditions, the look-ahead optimizations are able to pre-position the system for future system needs in an economically efficient way. If the payment of uplift is necessitated as a result of these optimal solutions, it is because the relevant optimization system has determined that one or more “lumpy” (*i.e.*, insufficiently flexible) generators must operate at its minimum output level for all or some of this period, and that this outcome is the least total cost means of operating the system over the duration of the system’s “look ahead” time horizon.

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?

Each resource that clears in the day-ahead market receives an hourly cleared output level (or schedule) for the next operating day. By 17:00 prior to the operating day, ISO-NE provides resources with schedules developed during the RAA that incorporate the ISO’s updated information and system load forecast. These schedules are not binding start-up and run-time instructions until the system operators call each resource’s operator to confirm these instructions;

these calls are made between 19:00 and 21:00 prior to the operating day. (In certain cases, system operators may provide earlier notifications if necessary due to long generator start-up and notification times.)

Commitment decisions made during the operating day in response to unanticipated system events are generally situation-dependent, and a unit's flexibility may be factored into the commitment time notification. Fast-start resources, as noted previously, are normally committed during real-time operations by the GCA/dispatch process.

> *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.*

Broadly, ISO-NE's real-time prices are calculated by its real-time UDS, not by the RAA and GCA, which are the ISO's other primary look-ahead optimization systems. Specifically, the RAA process is a commitment-only optimization system and does not produce prices. Likewise, the intra-day GCA look-ahead optimization system does not directly determine real-time prices, but its recommended commitment solutions for fast-start units will affect real-time prices. Its solutions are advisory, as it is a decision support tool for the system operators that (among other things) can identify the need to pre-ramp slow-moving generators.

For example, suppose an expensive but slow-ramping generator must be dispatched up now to meet energy demand in a future hour as part of the least-cost optimization over a multi-hour period. This non-marginal generator would not set the energy price while ramping, and will simultaneously displace the energy production of (one or more) other, lower-priced resources during the periods when the generator is ramping up "out-of-merit."

That combination of outcomes will tend to lower the LMP, relative to the LMP that would prevail without pre-ramping the expensive slow-moving generator, at two times: *(i)* the period when the unit is ramping up, and *(ii)* during the peak demand period (when, absent the pre-ramping, the system might not have been able to meet its energy or reserve requirements and LMPs may have reached scarcity-price levels). Despite being part of the least-cost system optimization over a multi-hour period, the inflexibility of this expensive, slow-ramping generating unit may result in it receiving uplift over the balance of its total commitment period that day.

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

ISO-NE's procedures minimize the incidence of unit commitments outside of the security-constrained economic commitment and dispatch processes. This is due to the extensive modeling of system operating limits, single (N-1) and multiple (N-1-1) security constraints in the commitment and dispatch system software, and the look-ahead optimization horizons used in the RAA process and the GCA intra-day optimization. These look-ahead features allow the ISO to account for projected future conditions in the most economic, least-cost way when making commitment decisions, and to achieve commitment outcomes that satisfy the system's transmission security constraints throughout the balance of the optimization horizon. However, even with commitment and dispatch optimizations that minimize total costs over a multi-hour horizon, economically-committed units may nonetheless require uplift payments due to their inherent "lumpiness" and the inflexibility of existing generating technologies.

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.

The decision as to whether a look-ahead optimization tool should be advisory or should produce binding commitment/dispatch instructions is difficult, and will depend on situation-specific considerations such as the accuracy of the look-ahead optimization systems in practice, the costs of errors they may produce (if judged after the fact), and the alternative processes and market options available.

An important consideration is the length of the optimization period. As noted in the answer to Question C.3 below, there are a number of assumptions about future system conditions that must be employed with any look-ahead optimization tools. Reality will invariably differ from these assumed future conditions by some degree, and the likelihood that actual conditions will differ from these assumptions increases with the length of time over which the optimization is performed.

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

Please refer to prior responses; we have not identified other potential or actual benefits that merit discussion.

3. Please discuss the complexities and limitations of look-ahead modeling, as well as any potential unintended consequences that could arise from the implementation or enhancement of look-ahead modeling tools.

The fundamental limitation of look-ahead modeling relates to the potential uncertainty of the information it requires about future conditions. The set of assumptions that are required for look-ahead optimization tools in a modern power system are extensive. For example, ISO-NE's GCA system considers a long list of forecasts and assumptions before recommending intra-day start up and shut-down times for fast-start units, identifying the potential need to pre-ramp slower-moving generating units during the day, and providing an estimate of future system states. These forecasts and assumptions include:

- system load forecasts;
- renewable energy output forecasts;
- planned returns from generation outages;

- future system topology changes, both within the New England Control Area and its neighboring Control Areas;
- the future status of all generating units (operating availability, fuel limitations, etc.);
- projected external interchange levels, by interface; and
- market participants' energy supply offer prices and operating parameters for future hours.

If all of this information is perfectly accurate, the commitment recommendation from a look-ahead optimization tool will be the least-cost solution (when judged after the fact). However, it is unreasonable to expect complete accuracy given the uncertainties surrounding many of these parameters (most significantly, load forecasts, renewable energy output forecasts and unanticipated unit outages) in future hours.

If the predictions of future system conditions are wrong, an unnecessarily expensive solution may result and materially affect real-time prices. For instance, if the load forecast is too high, the GCA look-ahead optimization system may recommend committing several expensive fast-start units. Under the current market rules for fast-start resources, real-time prices would not be significantly impacted and the cost of these fast-start resources would be paid (in large part) in the form of uplift; under the revised fast-start pricing rules, however, LMPs could increase significantly. Conversely, if the load forecast is too low, too few resources may be committed by a look-ahead optimization system, possibly causing scarcity conditions (a shortage of operating reserves) and extreme prices in the real-time market.

To make the most of its look-ahead systems and minimize uncertainties, operators incorporate the latest and best unit de-rating information before look-ahead models are executed, and then continually review load forecasts (which grow more accurate with time) and adjust recommendations. In addition, the ISO has developed a sophisticated next-day and near-term wind output forecasting system, and, as part of its corporate focus on value-added technical research projects, is researching robust optimization and stochastic optimization techniques. This research offers the potential to help large-scale power system operators better address the uncertainties inherent with look-ahead optimization tools.

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.*

Please see the response to the prior question.

b. *Please describe any other challenges, complexities, or practical limitations associated with look-ahead modeling. Where possible, please provide quantitative examples.*

In the current implementation of the GCA intra-day look-ahead optimization, the ISO assumes one system "topology" holds for all look-ahead study intervals. In simple terms, this means the transmission network is assumed not to change during the look-ahead horizon. However, this is not true in reality; transmission system elements come into and out of service within the models' look-ahead horizons for both routine and emergency maintenance, for example. These changes in future transmission system topology may affect the optimal commitments and solutions.

To capture changes in transmission system topology, the ISO has considered improvements to the look-ahead optimization model and additional security analysis checks (constraint testing) for future time periods. However, incorporating changes in the transmission system topology for each study interval increases the size and computation time for the multi-period optimization model substantially. Given the capability of the current commercial optimization solvers and the practicalities of time-to-solve constraints for real-time operational tools, this remains a limitation of look-ahead modeling.

There are other challenges associated with the state of development of look-ahead tools. These include the tools' inability to completely capture voltage and stability limitations in an alternating current network, given that look-ahead models use a direct current network model.

D. Uplift Allocation

(¶ 64) While there is general consensus that uplift allocation should follow cost-causation principles, questions remain about: how to define appropriate cost-causation categories for uplift; whether any RTOs/ISOs currently have a best practice for allocating uplift charges; the extent to which uplift charges should be allocated to virtual transactions; and the benefits of improved uplift allocation relative to the complexity of market rules involved. As such, we direct each RTO/ISO to submit additional information related to its uplift allocation methodologies, as discussed below.

Before addressing the detailed questions posed in this section, we first provide several broad observations about uplift in New England, its causes, and its allocation.

In New England, uplift accounts for one to two percent of total energy market value annually. As discussed in the ISO's responses in section B of this report (in relation to uplift associated with managing multiple (N-1-1) contingencies)), the root cause of much of this uplift is the lumpiness and inflexibility of generators that are committed and dispatched, economically, as part of the least-cost, security-constrained optimization of the power system.

While the ISO's goal is to ensure that the costs of operating an efficient, reliable power system are reflected in transparent market prices, it is also concerned that the uplift that remains today is the product of complex technological problems related to the inherent "lumpiness" and inflexibility of current generation technologies. At even a conceptual level, it remains unclear how this fundamental outcome of LMP-based power markets should be incorporated into a cause-and-effect-based method of uplift cost allocation.

At a practical level, applying cost causation principles to the allocation of uplift is difficult to perform with reasonable accuracy or validity. In principle, if only one element of the entire power system changes in real-time from the day-ahead operating plan, and subsequently there is greater uplift in real-time than occurred day-ahead, then one might reasonably infer a cause-and-effect relationship. However, in practice, there are many factors that concurrently change from day-ahead to real-time, and disentangling which of these changes "caused" additional uplift – and by how much – is not a simple matter. (One of these factors may be the ISO's own actions, in dispatching to meet inaccurate load forecasts.) Indeed, ISO-NE anticipates that ascribing cause-and-effect conclusions to much of the uplift that remains in New England's markets would be difficult to substantiate without undertaking extensive statistical studies – and even then, such studies may not yield clear cause-and-effect conclusions that result in broadly agreed-upon assessments of cost.

As a consequence, in the end, it may be that uplift should be allocated based on the Commission's beneficiary-pays principles. Indeed, as discussed in detail further below, approximately half of all uplift in the New England system is already allocated on the basis of beneficiary-pays principles – in no small measure because, for many forms of uplift, it is difficult to identify cause-and-effect relationships as required to implement cost-causation principles.

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).*

The ISO's approach to allocating uplift charges follows the Commission's guidance on allocation based on both "beneficiary pays" and "cost causation" principles, depending on the type of uplift.

As discussed in greater detail below, most uplift in the New England system falls into three broad categories: first-contingency protection uplift, which comprises uplift charges associated with units committed to ensure the system satisfies energy demand, reserve requirements, and first (N-1) contingency security requirements; second-contingency (LSCPR) protection uplift, which comprises uplift charges associated with multiple-contingency (N-1-1) security requirements (discussed previously in response to Question B.4); and uplift charges associated with units committed for voltage control. (Additional, minor uplift categories are detailed in the table further below.)

In the day-ahead market, the first contingency and second contingency resource protection uplift charges are allocated to load obligations – which are paid by wholesale energy buyers – on the basis of beneficiary-pays principles. The uplift that occurs in the day-ahead market reflects the least-cost outcomes from the security-constrained economic commitment and dispatch of the power system, and arises due to the inherent "lumpiness" of resources when energy is priced on the basis of locational marginal pricing principles. In general, there is no identifiable participant behavior "causing" these uplift charges to be incurred, other than the demand of buyers in the day-ahead wholesale market. Accordingly, since wholesale buyers are the beneficiaries of an efficient, least-cost day-ahead market – uplift and all – the costs of operating the day-ahead market (with a few exceptions noted below) are allocated to load obligations.

In the real-time market, uplift charges associated with second contingency protection are allocated to load obligations, again on the basis of beneficiary-pays principles. However, first-contingency uplift charges are allocated based on the deviations of participants' real-time positions from their cleared day-ahead positions, on the basis of cost-causation principles.

In both the day-ahead and real-time markets, uplift associated with units committed to provide voltage control is allocated principally to transmission companies, under a cost-causation design intended to incent construction of a more robust transmission system.

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.

As part of the ISO's Wholesale Market Project Plan, ISO-NE and stakeholders will assess the uplift charge allocation methods beginning, at the earliest, in late 2016 or 2017. The ISO has not developed a specific proposal to modify the existing uplift allocation process.

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.

The ISO has not identified any specific transaction types, resource types, schedule deviations, or other uplift drivers that cause uplift on a regular basis, but that 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.

As discussed in response to Questions B.1 and C.2.b.i above, the ISO's least-cost optimization systems may recommend certain actions (*e.g.*, keeping a currently-uneconomical unit online) in advance of an upcoming peak hour in order to minimize total production costs over the balance of the day. Those actions may be the least-cost, most efficient means to serve energy demand over the remaining operating day, and yet they may result in uplift due to the inherent inflexibility of the generator at issue (*i.e.*, its inability to promptly shut down now, and then restart later when needed for the peak hour).

In these cases, it is often difficult – if not impossible – to identify a participant action that could be accurately determined to have "caused" the uplift. This illustrates a general, and in the ISO's view, crucial, caveat to broad conclusions that uplift should be allocated on the basis of cost-causation: in a wide variety of circumstances, the root cause of uplift is the inherent "lumpiness" and inflexibility of generators that cannot be quickly dispatched down (to zero) promptly whenever their energy is no longer needed to meet demand. In these circumstances, the only reasonable basis for allocating the cost of the uplift credits that accrue to these generators may be on a beneficiary-pays basis. Ultimately, the consumer is the principal beneficiary when the power system is operated in the least-cost, most efficient manner, notwithstanding the uplift "caused" by generators' inflexibilities in the security-constrained economic commitment and dispatch.

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.*

The ISO is not aware of any evidence or investor concerns that its current uplift allocation method mutes generation investment signals.

As context, in New England, the ISO provides frequent and detailed information about uplift charges to all stakeholders. Specifically, each month, ISO-NE's Chief Operating Officer posts a report for stakeholders, and discusses the report at the monthly NEPOOL Participants Committee meeting.[25] On the topic of uplift, that report includes: the types of uplift and monthly and daily charges within each category; the allocation of the costs of that uplift; year-over-year uplift costs; the breakdown of the uplift by day-ahead and real-time; for first contingency uplift, the deviation type (generation, increment offer, import or load obligation);

[25] *See, e.g.*, slides 57-73 of the January 2016 COO Report at http://www.iso-ne.com/static-assets/documents/2016/01/npc_20160108_composite3.pdf.

for second contingency uplift, the relevant zone; and uplift charges as a percent of the energy market by month (overall and per category).

ISO-NE acknowledges that, in principle, providing more detailed or granular data regarding uplift (including possibly the names of the specific resources regularly receiving large uplift payments) could enable a potential new entrant to better understand the frequency and amount of revenue currently provided at one location in the grid, relative to another location. However, this type of information is unlikely to serve as a material driver of new entry decisions, as new generation projects are based on the developer's assessment of future market conditions over many years. These assessments are based primarily on the expected revenue streams provided by the energy and capacity markets administered by ISO-NE, with the energy market revenue component assessed using forecasts of future wholesale electricity and fuel prices.

Uplift at a specific location is potentially transient, as it is sensitive to the entry of a new facility at that location, and to the ISO's decisions concerning upgrades to the transmission system over time. For these reasons, uplift is likely quite difficult for developers to predict with any accuracy, and ISO-NE is unaware of any evidence (or compelling arguments) that the current level of uplift information and its allocation mutes investment signals in New England.

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.*

The following table summarizes each type of uplift, the allocation basis (*i.e.*, cost causation or beneficiary pays), and the specific allocation.

Allocation Category	**Allocation Basis**	**Specific Allocation**
System 1st Contingency (Day Ahead Market)	Beneficiary Pays	Day Ahead Load Obligation
External Transaction (Day Ahead Market)	Cost Causation	Allocated to certain day-ahead transactions at the specific external node involved
System 1st Contingency (Real Time) (including External Transactions)	Cost Causation	System 'Daily Deviations,' the sum of generator deviations, load deviations, generation obligation deviations at external nodes, and increment offer deviations
Local 2nd Contingency (Day Ahead and Real Time)	Beneficiary Pays	Load Obligation in the Reliability Region served
Voltage (Day Ahead and Real Time)	Cost Causation *and* Beneficiary Pays	System Regional Network Load[26] and Open Access Same-Time Information Service (OASIS) reservations
Regional High Voltage (Day Ahead and Real Time)	Cost Causation	Zonal Regional Network Load
Special Constraint Resources (Real Time only)	Cost Causation *and* Beneficiary Pays	Specific Participating Transmission Owner (PTO) requesting the service (*i.e.,* the dispatch of units to manage distribution-level constraints)
Ancillary Services Uplift (regulation and reserves markets)	Beneficiary Pays	Real-Time Load Obligation

[26] The majority of Regional Network Load is assigned to Transmission Owners and municipal systems. A minimal share of this determinant may be assigned to generators using Regional Network Service in a given month.

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;*

As indicated in the table above, there are instances in which uplift is allocated to the entities that nominally "caused" the cost to be incurred. Specifically, real-time first contingency uplift charges are allocated to entities (generators, load, and virtual transactions) that deviated from their day-ahead cleared positions (that is, their MWh purchases or sales in the day-ahead market). Similarly, day-ahead uplift payments caused by scheduled import or export transactions that exceed the capability of the applicable external interface limit are charged to all cleared transactions at that external node. Finally, as noted previously, transmission owners are allocated the uplift charges for low-voltage support and high-voltage protection (by zone).

The remainder of uplift is allocated to load obligation, which is paid by wholesale energy buyers – who are the beneficiary of the underlying transactions. This reflects the ISO view that, in these instances, the primary driver of uplift is the "lumpiness" of generators and is not "caused" by any identifiable participant action. In other words, respecting the various characteristics of generators, including their minimum output levels, minimum run times, and minimum startup times, often results in uplift as these generators are efficiently committed and dispatched as part of the least-cost security-constrained market solution.

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);*

In the real-time market, the first contingency uplift charges allocated to generators and external transactions are based on the real-time deviations from these participants' cleared day-ahead positions. A Market Participant's deviation from its day-ahead load obligation, which includes cleared decrement (virtual demand) bids, is netted on an hourly basis over all locations. Import external transaction deviations are also netted on an hourly basis over all locations. Hourly generator and increment (virtual supply) deviations are not subject to netting. Daily deviations are calculated by summing the absolute values of the hourly deviations for load, imports, generation and increment offers.

i. explain whether and how uplift related to real-time resource commitments for transmission constraint management is allocated to schedule deviations;

Assuming that "transmission constraint management" means commitments for multiple (N-1-1) contingency protection (*i.e.*, LSCPR commitments), such uplift is allocated to load obligations, consistent with the beneficiary-pays principle. If the commitment is limited to a zone, only the load obligation within the zone pays. *See* the table following Question D.3.

ii. explain whether and how uplift related to real-time resource commitments for system reliability is allocated to schedule deviations;

Real-time resource commitments for system reliability are classified by the reliability requirement, as discussed previously (*e.g.*, first contingency protection, second contingency protection, voltage support, and so on). As described above in response to Question D.3.b., real-time first-contingency uplift charge allocations are based on deviations from cleared day-ahead positions.

c. Explain the locational granularity with which this uplift is allocated (e.g., RTO-wide, zonally);

As discussed previously, first-contingency uplift charges are allocated RTO-wide, unless they are related to a specific external node, in which case the uplift is allocated to transactions at that node. Local second-contingency protection resource commitment uplift charges are allocated to load obligations by reliability zone.

> *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;*

Uplift charges associated with units committed to provide voltage support are allocated to all transmission providers system-wide. Uplift charges associated with units committed for regional high voltage are allocated solely to the transmission providers in the affected reliability region, on the principle that conditions requiring high-voltage protection are local (*i.e.*, not system-wide) in nature. The allocator for voltage support commitments also includes a "beneficiary pays" component, whereby a portion of the uplift is allocated to external transactions that are benefiting from the voltage support.

> *d.* *Explain whether day-ahead and real-time energy and ancillary services market uplift is allocated on an hourly, daily average, or another basis;*

The temporal allocation rules vary, and are summarized as follows:

- NCPC for first and second contingency commitments is allocated daily, pro-rata on the total daily value of the allocation factor;
- NCPC for voltage support is allocated hourly;
- NCPC for special constraint resource commitments is allocated hourly to the party that requested the commitment;
- NCPC for external transactions, and certain other special NCPC payments, is allocated hourly;
- Uplift payments for the regulation and reserve markets are allocated hourly to load obligation.

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;*

Day-ahead first contingency and all second contingency uplift charges are allocated to load obligations, as the beneficiary of the underlying transactions that are part of the least-cost, security-constrained economic commitment and dispatch solution. As discussed previously, this reflects the ISO's view that, in these instances, the root cause of this uplift is the intrinsic "lumpiness" of generators – that is, the uplift results from the minimum output levels, minimum run times, and other inflexibilities of generators dispatched as part of the least-cost means of operating the power system – and not from any specific participant's action that can be reasonably determined to have "caused" the uplift.

As noted at the outset of this Section D, at even a conceptual level, it remains unclear how the inflexibilities of generators committed and dispatched as part of the least-cost operation of the power system – which is the root cause of much uplift in LMP-based power markets – should be incorporated into a cause-and-effect-based method of uplift cost allocation. When uplift is paid in these situations, the security-constrained economic commitment and dispatch solution has determined that these units' operation is a necessary component of the most cost-effective means to satisfy consumers' energy demand while meeting all reliability requirements. As energy consumers are the beneficiaries of operating the power system at least-cost, load obligations are presently allocated these uplift costs.

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.*

The only exemptions from the allocation of uplift are instructed resource deviations (including Dispatchable Asset Related Demand resources), Coordinated External Transactions, and Intermittent Power Resources.

Regarding the exemption for instructed resource deviations (from day-ahead cleared positions), ISO-scheduled resources that are on-line and following dispatch instructions are exempt from allocation of real-time first contingency uplift, which is otherwise allocated to deviations. These situations include units that follow ISO instructions not to run in the case of a minimum generation emergency, and changes in energy consumed by Dispatchable Asset Related Demand resources at the ISO's instruction. The rationale for these exemptions is to avoid creating situations where a resource may have a financial incentive (*i.e.*, minimization of its uplift charges) to ignore the ISO's real-time operating instructions.

The CTS system allows participants in New England and New York's markets to make unified real-time bids to simultaneously purchase and sell energy on each side of the interface. In developing the related rules, ISO-NE and NYISO eliminated certain fees and charges that served as disincentives to engage in trade, impeded price convergence between the regions, and raised total system costs. Specifically, ISO-NE eliminated uplift charge allocations to external transactions between the two regions that use the CTS system, on a reciprocal basis with NYISO.

Intermittent Power Resources are not required to participate in the day-ahead energy market. However, if they choose to do so, under the current market rules they are exempted from deviations for purposes of calculating real-time uplift.

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.*

Day-Ahead NCPC Charges by Category and Allocator; October 1, 2014 - September 30, 2015

Day-Ahead NCPC	**$41.6 Million**
DA First Contingency – Day-Ahead Load Obligation	35.6%
DA Second Contingency - Regional Real-Time Load Obligation	57.7%
DA Voltage - Regional Network Load (TOs) & external transaction reservations	6.7%
Total	100.0%

Real-Time NCPC Charges by Category and Allocator; October 1, 2014 - September 30, 2015

Real-Time NCPC	**$78.2 Million**
RT First Contingency - Generator Deviations	8.9%
RT First Contingency - Load Deviations	49.4%
RT First Contingency - Increment Deviations	7.1%
RT First Contingency - Import Deviations	8.8%
RT First Contingency - Real-Time Load Obligation (1)	0.8%
RT Second Contingency - Regional Real-Time Load Obligation	22.6%
RT Voltage – Regional Network Load (TOs) &external transaction reservations	2.3%
RT Special Constraint Resources (Transmission Owner requests)	0.1%
Total	100.0%

(1) Certain Special Case NCPC is billed to Real-Time Load Obligation and tabulated in this category. Includes uplift for generator performance audits and postured resources.

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.*

While ISO-NE is not familiar with the details of MISO's cost allocation rules, we understand that MISO's approach emphasizes determining cost causation. (We will address MISO's practice of allocating costs to virtual transactions in our response to Question D.6, below.) ISO-NE currently uses a nominal cost-causation basis for the allocation of the largest category of uplift, real-time first contingency uplift (about 51% of the uplift paid in the year ending on September 30, 2015). Specifically, the ISO allocates these costs based on deviations from day-ahead schedules.

Notwithstanding the allocation of certain costs to deviations, ISO-NE does not agree that practice of allocating uplift based on deviations is unequivocally a "best practice." In this paradigm, a deviation caused by, for example, an unplanned generator outage is allocated the costs of uplift for subsequent supplemental commitments – even if other factors (such as load under-forecast errors by the ISO, or unrelated concurrent transmission outages) also contribute to the need for supplemental commitments. In fact, that same generation outage could, in some cases, decrease total uplift costs if the ISO has over-forecast system load; in that case, allocating uplift to the outage-caused deviation would actually penalize a resource when the outage shut down a resource that was no longer needed and that outage lowered the total cost of operating the power system.

More generally, the apparent basis for allocating real-time first-contingency uplift costs to deviations (from day-ahead positions) is the assumption that such deviations will tend to *(i)* result in supplemental commitments by the ISO, which then *(ii)* reduce LMPs and *(iii)* require the supplementally-committed resource (and possibly other resources) to be paid uplift. The problem with this logic is that often these assumptions are simply false. Higher load levels in real-time than for the same hour day-ahead infrequently necessitate supplemental commitments in New England, and generator outages in real-time often *increase* LMPs (thus reducing uplift), not decrease LMPs. As a result, the rationale for allocating real-time uplift to deviations frequently does not hold up well under close inspection of the underlying cost-causation assumptions.

An accurate determination of the impact of a specific real-world action on aggregate uplift payments requires detailed information about the then-current state of the system – and a counter-to-fact, "but for" assessment of what uplift would have been incurred *in the absence* of the specific deviation. The ISO is not convinced that, in the real-world where many things change concurrently, existing tools and information can yield clear, accurate, and practical methods for performing these counter-factual analyses. Less rigorous methods for inferring cost-causation may be easier in practice and may seem reasonable in some situations, but it is difficult to draw reliable conclusions about their validity without substantial statistical studies. Even then, such studies may fail to yield clear, broadly-agreed conclusions that can be implemented in 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?

As shown in the chart in the response to Question D.3, the ISO has created categories of uplift and varied its uplift charge allocation practices based on the nature of the uplift payments. Certain situations (*e.g.*, voltage support, special constraint resource commitments for local distribution system reliability) are easier to assess, from a cost-causation standpoint, than others (*e.g.*, first contingency uplift payments, as discussed in the previous answer). As noted in prior responses, much of the uplift that arises for units committed as part of the least-cost, security-constrained economic commitment and dispatch process has as its root cause the "lumpiness" of generation resources that receive the uplift.

In real time, it is difficult to assess cost causation accurately for uplift because multiple changes in system conditions commonly occur concurrently. Disentangling the contribution to total uplift of each change from the day-ahead operating plan requires detailed information about extant system operations, and has questionable validity without constructing a "but for" analysis of what uplift would have been in the absence of each individual change from the day-ahead plan – an analysis that may produce different answers in each circumstance.

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

Please see previous responses. The ISO has not developed other practical, alternative potential approaches to allocating uplift changes based on cost-causation.

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.*

As stated above, the ISO allocates the costs of the largest category of uplift (real-time first contingency uplift) to deviations, including virtual transactions.

The ISO, its internal and external market monitors, and its stakeholders have reviewed this practice and been unable to reach agreement on the appropriate allocation of costs to virtual transactions. Topics discussed included the value of virtuals to the competitiveness and overall functioning of the day-ahead market; the roles of "helping" (or decrement) virtual bids in potentially reducing uplift and of "hurting" (or increment) virtual offers in potentially increasing it; and the fact that all virtuals are deviations such that the allocation of uplift to them constitutes a *de facto* tax on those transactions that can be expected to reduce the volume of virtual participation.

Ultimately, the ISO's internal market monitor recommended that virtuals be excluded from the assessment of costs to deviations, while the external market monitor recommended that the ISO calculate net deviations (*i.e.*, "hurting" deviations less "helping" deviations) and assess uplift to the net deviations on a pro rata basis, with the remainder of uplift allocated to all real-time load.[27]

After assessing these viewpoints, in 2014, ISO-NE proposed to reallocate real-time first contingency charges from virtual demand as well as non-virtual demand deviations from day-ahead positions ("helping" deviations). The reallocation would have affected about 20% of this category of uplift. Ultimately, stakeholders failed to support the ISO's proposal, and the ISO chose not to move forward with the change without stakeholder support.

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.*

ISO-NE has not had the opportunity to consider this proposal in detail or with the benefit of stakeholder input. Later this year or next year, the ISO and stakeholders plan to conduct a comprehensive assessment of cost allocation practices, including the allocation of costs to virtuals. At that time, the parties may elect to consider excluding real-time uplift from the costs allocated to virtual transactions.

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[27] *See, e.g., ISO New England's Internal Market Monitor's 2014 Annual Markets Report* at p. 10 (http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf) and *2014 Assessment of the ISO New England Electricity Markets* by Potomac Economics, External Market Monitor, at p. 9 (http://www.iso-ne.com/static-assets/documents/2015/06/isone_2014_emm_report_6_16_2015_final.pdf).

E. Transparency

(¶ 80) Sufficient information regarding uplift drivers, charges and operator actions may be lacking for market participants to participate efficiently in RTO/ISO markets. Specifically, there appears to be a lack of clarity regarding what uplift RTOs/ISOs should report according to specific drivers, and the feasibility of and appropriate limits to releasing information more frequently, more promptly, and with additional geographic granularity. We also appreciate that there may be unintended consequences associated with increasing transparency. As such, we direct each RTO/ISO to submit information related to the transparency of its practices, as discussed below.

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.

ISO-NE believes that it provides sufficient information about uplift, addresses stakeholder questions on this topic in a timely manner, and provides quantitative information in detail through numerous publications and reports. ISO-NE has no specific plans to enhance the level of information it presently provides about uplift, operator actions, or other related factors affecting market outcomes.

As noted in response to Question E.2 below, the ISO presently provides extensive information about uplift payments to stakeholders, including a monthly presentation and report from the Chief Operating Officer, following which stakeholders have a question-and-answer session. This report and question-and-answer session cover any significant operating events each month, including uplift consequences.

Significantly, ISO-NE cannot increase the level of detail it provides about uplift and resource-specific operator actions without changing the longstanding ISO New England

Information Policy (the "Information Policy").[28] That policy, which is part of the ISO's Tariff and was developed by the region's stakeholders before ISO-NE was created, prevents ISO-NE from sharing market participants' commercially-sensitive asset-specific operating information.

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

As previously discussed in response to Question D.2.c above, ISO-NE provides comprehensive information to stakeholders regarding uplift drivers and operator actions each month. The monthly Chief Operating Officer's report includes: the types of uplift and monthly and daily charges within each category; the allocation of the costs of that uplift; year-over-year uplift costs; the breakdown of the uplift by day-ahead and real-time; for first contingency uplift, the deviation type (generation, increment offer, import or load obligation); for second contingency uplift, the relevant zone; and uplift charges as a percent of the energy market by month (overall and per category). These reports also cover any special operational events that resulted in significant operator actions outside the context of normal, economic operations, and provide an opportunity for verbal questions and answers about these actions and about NCPC generally. This public information does not include resource-specific data.

In addition to the Chief Operating Officer's reports, ISO-NE publishes weekly, monthly, and quarterly Market Operations Reports that contain, among other things, explanations of notable operational events and detailed tables on NCPC payments by operational category during each reporting period.[29] Uplift information is also available online at settlement frequency. More specifically, each market participant's settlement report details (to the payee) the reasons

[28] The Information Policy is located at http://www.iso-ne.com/static-assets/documents/regulatory/tariff/attach_d/attachment_d.pdf.

[29] These weekly, monthly, and quarterly reports are publicly available at http://www.iso-ne.com/markets-operations/market-performance/performance-reports.

for any reliability commitments (*e.g.*, second contingency protection, voltage support, etc.), and (to the payor) overall class of uplift.

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.*

ISO-NE does not believe such changes are necessary given the existing level of granularity employed in uplift reporting. As noted previously in response to Question D.2.c, the ISO does not believe that the provision of more granular (*i.e.*, locational) information about uplift would materially affect investors' entry decisions. Moreover, when uplift is primarily a result of the "lumpiness" of the generators dispatched at the relevant point in time, a market participant would need to know the details of the entire dispatch (including unit-level output information) to understand how this dispatch resulted in uplift.

b. *Please also describe the tradeoffs involved in refining uplift categories.*

As previously noted, a significant issue in providing more refined uplift information is ISO-NE's Information Policy, which would have to be amended to permit any resource-specific information disclosures about uplift or its drivers. Such changes are likely to be contentious, and it is unclear how useful the information would be to participants, as indicated in the response to the previous question.

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.*

As a preliminary observation, ISO-NE presently publishes the number of generating units that are supplementally-committed after the close of the day-ahead market (excluding commitments that may be made in real-time). This information is published each day in the Morning Report on the ISO's web site.[30] The ISO does not publish the amount of capacity (MW) committed, to avoid disclosing resource-specific information in violation of the ISO-NE Information Policy.

Turning to practicalities, in the foregoing question, the meaning of "uneconomic dispatch" is unclear. If "uneconomic" is determined strictly by whether ISO-NE's security-constrained unit commitment software was employed to determine whether (and which) resources are committed after the close of the day-ahead market, then providing this information might be feasible. However, that is likely not to be particularly informative; not only are such events uncommon, the vast majority of all such commitment decisions are determined by these least-cost security-constrained unit commitment software tools.

Alternatively, if "uneconomic dispatch" refers to a forward-looking evaluation of the resource's offer costs relative to projected LMPs over the expected commitment schedule of a resource, then that type of report is unlikely to be feasible. When resources are committed after the day-ahead energy market closes, that action will generally affect (to some extent) real-time prices; however, as noted in response to Question C.2.b.iii, ISO-NE does not calculate projected LMPs for the balance of the day as part of its supplemental commitment (RAA) decision process. Thus, given current software and systems, it would not be possible to evaluate, in advance, the hours or the energy for which a supplementally-committed resource may be "uneconomic" during the operating day.

[30] http://www.iso-ne.com/markets-operations/system-forecast-status/morning-report.

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?*

ISO-NE's Information Policy requires the ISO and participants to protect Confidential Information, which is limited to trade secrets or commercial or financial information, "the disclosure of which would harm the Furnishing Governance Participant or prejudice the position of that Governance Participant in the New England electricity markets."[31] Confidential Information remains the property of the relevant Governance Participant.[32]

Section 3.0 of the Information Policy lists specific categories of information and details their treatment. With regard to the Commission's question about restrictions relevant to the release of uplift information, Section 3.0(d) ("Asset Specific Information – Near Real Time") prohibits the sharing of information like generation levels, operating limits, unit forecast information and operational information. Section 3.0(f) ("Meter, Bid and Offer Data") prevents the ISO from sharing bid and offer data with anyone except the relevant asset owners. In other words, this asset-specific information and meter, bid and offer data have been determined to be "Confidential Information."

Conversely, Section 3.0(a) describes various categories of public information. This includes bid and offer data published approximately four months after the bids and offers were in effect, "provided that the information is presented in a manner that does not reveal the specific

[31] Information Policy at Section 2.1(a).

[32] *Id.* at Section 2.0.

load or supply asset, its owners, or the name of the entity making the bid or offer, but that allows the tracking of each individual entity's bids and offers over time."

If stakeholders would like this bid and offer information provided with different periodicity or detail, and determine that the desired information does not constitute "Confidential Information," ISO-NE will propose the relevant changes to its Tariff and implement the resulting protocol. The ISO will also discuss with stakeholders the appropriate characterization of any other information they would like publicly disclosed.

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?

As previously discussed, ISO-NE provides comprehensive information on uplift to stakeholders each month. In addition, daily data on uplift amounts are posted to the ISO's public website approximately four business days after the operating day.[33] The information includes total amounts of uplift paid by category each day, and is region-specific for second contingency (LSCPR) and high voltage payments. The posted data do not include any generator-specific Confidential Information; rather, individual market participants who are credited and/or charged are provided with their specific Confidential Information through ISO-NE's secure Market Information Server report delivery system.

Given current software and systems, and the time required to process and calculate all of the market settlements necessary to determine uplift amounts, it is not practical for the ISO to deliver daily uplift information more quickly than the current timeframe (*viz.*, approximately four business days following the operating day).

[33] http://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/ncpc-credits-summary.

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?*

As noted above, uplift is generally the product of least-cost, security-constrained optimization systems that determine the most economical commitment and dispatch solution. The uplift calculation does not occur in real-time, but is a function of ISO-NE's settlement processes. As noted in the preceding response, it is necessary to process and calculate many other market settlements before determining uplift amounts, and the resulting uplift information is publicly released within approximately four business days. Currently, this process is efficiently run; changes to expedite it would be expensive and, in the ISO's estimation, unnecessary given the amount of money at stake.

In New England, it is uncommon for operators to dispatch resources outside of the security-constrained economic commitment and dispatch software. While it would be technically feasible to release information about such action close to real-time, the disclosure of resource-specific information is prohibited by the Information Policy.

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?*

Zonal reporting occurs now where it is applicable. (See the response to Question E.4 above.) ISO-NE believes this is an appropriate geographic granularity.

ii. *Can zonal reporting of each uplift category be accomplished without revealing proprietary information?*

ISO-NE utilizes zonal reporting where relevant. Should a disclosure reveal a participant's identity, ISO-NE would modify the granularity of the disclosure.

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?)*

ISO-NE believes that zonal reporting can provide a sensible balance between transparency and protection of participants' information, particularly when the allocation of the uplift charges is also zonally-based.

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. 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?*

ISO-NE believes that its comprehensive reporting of uplift information within days of real-time is sufficiently transparent and prompt. It is unclear what purpose would be served by enhancing the speed or granularity of the information. Moreover, as noted in response to

Question E.4.a above, changes to expedite the assembly of uplift information would be expensive to implement.

As discussed in detail in Section D of this report, ISO-NE currently provides uplift charge information for many categories; these current practices are consistent with the suggestion in this question that the uplift information categories be "both narrow enough to be useful and broad enough that individual unit profiles cannot be discerned." Usefulness, in this context, means conveying the general reason for the uplift: *e.g.*, voltage support, local second contingency protection, external interface congestion, distribution-level constraints ("special constraint resources"), and so on, as explained in response to Question D.3.

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?

Similar to NYISO, ISO-NE currently reports operational events that may be relevant to uplift in near-real time. These events include: changes ("cuts") to scheduled external transactions in real-time to preserve operating reserves; the number of supplemental commitments in the day-before Reserve Adequacy Analysis process, if any; and any operating procedures to avoid a capacity deficiency, or that invoke emergency actions, during the operating day. Additional reporting of operator actions may be technically feasible, but – if it entails resource-specific information – may violate the Information Policy.

As an aside, ISO-NE notes that the Commission's question indicates that NYISO is "reporting real-time uplift." ISO-NE assumes that this is not a precisely accurate statement, as uplift is the economic product of market settlements run after the fact.

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.*

In ISO-NE, operations personnel operate in both normal and emergency conditions pursuant to extensive, predictable protocols and using well-defined algorithms and models. ISO-NE has undertaken a considerable effort to make these operational and engineering protocols available to New England stakeholders. The available protocols include: manuals; operating procedures; system operating procedures, including control-room operating procedures; master/local control center procedures; and planning procedures.[34]

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?*

As discussed above, ISO-NE's EMS includes a detailed network model. The network model is available to registered market participants through the ISO-NE website. The methodology for updating this model is transparent to participants, including through publication of the relevant system operating procedure (SOP-RTMKTS.0060.0010 – Update EMS Network Transmission Topology) and the operating procedure for inclusion of resource data (Operating Procedure 14 – Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources).[35]

[34] All are available at http://www.iso-ne.com/participate/rules-procedures. Confidential appendices are excluded.

[35] These procedures are available at the link in the preceding footnote.

Each time ISO-NE updates its network model, including by revising constraints and interface definitions, it releases a notice to the public through the ISO-NE website. Nodal-level information, such as the definitions of each "priced" node (also known as a "Pnode"), may be updated with each network model release and that information is publicly available on the ISO-NE website under Settlement Model Information.

b. Does the RTO/ISO release this information to all market participants?

Yes, see above.

c. What limits are necessary prior to disseminating changes to the RTO/ISO market model?

Given the need to control the distribution of the Critical Energy Infrastructure Information contained in the network models, ISO-NE limits access to those stakeholders who are registered with ISO-NE and have been granted access to the external distribution application for these data.

In conclusion, ISO-NE requests that the Commission accept the foregoing report.

Respectfully submitted,

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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 Commission Secretary in these proceedings.

Dated at Holyoke, Massachusetts this 4th day of March, 2016.

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