



# 2017 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

POTOMAC  
ECONOMICS

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## PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.<sup>1</sup> In this assessment, we provide our annual evaluation of the ISO's markets for 2017 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2017.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

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<sup>1</sup> The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."



## EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights (“FTRs”), and forward capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region’s resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

The ISO Internal Market Monitor (“IMM”) produces an annual report that provides an excellent summary and discussion of the market outcomes and trends during the year.<sup>2</sup> The IMM Annual Report shows:

- Energy prices rose 12 to 17 percent from 2016 to 2017 as natural gas prices increased by 19 percent. This correlation is consistent with our findings that the market performed competitively because energy offers in competitive electricity markets should track input costs.
- Fast-start pricing rules were implemented by the ISO in March 2017, which better reflect the costs of committing fast-start resources. This change contributed to higher energy prices in 2017 and led to significantly elevated reserve prices as well. As a result, total real-time operating reserve payments increased by 75 percent from 2016 to 2017 while NCPC costs fell.
- Load declined to its lowest level in the past 18 years. Average load fell 2 percent from 2016 to 2017 and peak load fell 7 percent. The decrease reflected mild weather conditions during most of the year (especially in the summer months), the increase in energy efficiency programs, and the strong growth in behind-the-meter solar generation.
- Capacity prices were over \$7 per kW-month in the 2017/18 Capacity Commitment Period (“CCP”), more than double prices in prior CCPs. The increase resulted from substantial retirements in FCA 8, which caused a capacity shortage and an administratively determined price. Prices in FCA 9 rose to \$9.55, before falling to \$7.03, \$5.30, and \$4.63 in FCAs 10, 11, and 12 as new resources entered and requirements fell. Pay-for-performance (“PFP”) rules will start with the CPP for FCA 9 in June 2018, which are expected to improve market incentives for good performance.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in 2017. This report is intended to complement the IMM report, evaluating the

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<sup>2</sup> See ISO New England’s Internal Market Monitor 2017 Annual Markets Report, available at <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>.

competitive performance of the market and focusing on key market design and competitive issues. Hence, this report includes:

- A Competitive assessment of the energy and ancillary services markets,
- Evaluation of fuel security challenges facing New England,
- Analysis of market operations during the 2017/18 cold snap,
- Assessment of key elements of the capacity market design,
- Analysis of market issues related to out-of-market uplift costs, and
- An evaluation of the Coordinated Transaction Scheduling (“CTS”) process with NYISO.

### Competitive Assessment

Based on our evaluation of the ISO-NE’s wholesale electricity markets contained in this report, we find that the markets performed competitively in 2017. Our pivotal supplier analysis suggests that market power concerns remain in Boston and market-wide under high-load conditions. However, our analyses of potential economic and physical withholding indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2017. Market power concerns in Boston will be further alleviated with the completion of the Greater Boston Reliability Project and when the Footprint Power combined-cycle plant comes into service.

In addition, we find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets, and was generally implemented consistent with Appendix A of Market Rule 1. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes.

To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. The ISO allows adjustments for fuel price changes, but it currently does not have procedures to allow opportunity costs resulting from fuel limitations in reference levels, which may lead to inefficient scheduling of some generators. It is particularly important to allow generators to reflect such limitations during gas scarcity conditions, since this is how generators conserve their limited fuel supplies for the optimal time. Hence, we recommend the ISO develop procedures to address this concern.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, the suppliers have the incentive to operate in a higher-cost mode and



receive higher NCPC payments as a result. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern.

### Addressing Winter Fuel Security Concerns

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region in recent years. Over the decade from 2010 to 2020, 4 GW of oil and coal-fired capacity has retired or will retire, while the remaining oil and coal-fired capacity in New England will be economically challenged by falling capacity prices, the phase-in of PFP, and the entry of state-subsidized resources. The ISO has signaled that its planning processes and market design lack the necessary elements to address reliability needs that are driven by fuel limitations. These concerns were heightened after Exelon announced plans to retire the Mystic generating station, which would likely result in the retirement of the Distrigas LNG import facility.<sup>3</sup>

Although the oil storage capacity and LNG import capability are potentially high enough to satisfy the demand for these fuels during a severe winter event, it would require very high utilization rates—above those observed in the past. Our fuel security assessment for a two-week severe winter period showed that while the system required more than a third of this capability in the winter 2014/15, and is projected to require a very high percentage of this capability if the Distrigas terminal is retired. Additionally, even if this terminal does not retire, the demand for oil and gas will exceed the available supply under a severe pipeline contingency in the 2023/24 cold snap scenario. This suggests that under these conditions, ISO-NE would lose its ability to serve the load for an extended timeframe.

These trends raise questions about whether the current planning processes and market requirements are adequate to ensure fuel security by motivating generators to procure adequate fuel. Section III of this report shows that recent experience during the 2017/18 cold snap highlights that the ISO can have surplus operating reserves in the real-time market even when the New England generator fleet is running very low on fuel. Market design changes may be needed to ensure that generators have incentives to conserve limited fuel supplies and allow market prices to efficiently reflect these fuel limitations. While ISO-NE's shortage pricing and PFP framework are designed to provide strong incentives for suppliers to be available during such conditions, these conditions may be difficult to predict and may need to be explicitly recognized in the ISO's planning processes to ensure that the ISO can satisfy its one-in-ten reliability standard (i.e., the expectation that the ISO would involuntarily cut load no more than one time in 10 years).

The ISO's Winter Reliability Program ("WRP") is scheduled to end by June 2018 when the PFP program becomes effective. While PFP has the virtue of being technology neutral and will

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<sup>3</sup> See ISO-NE's Operational Fuel Security Analysis, January 17, 2018 and ISO-NE's filing, Seeking a Tariff Waiver for Retaining Mystic 8 and 9 Units, Docket No. ER18-1509-000, May 1, 2018

provide strong incentives for generators to procure the fuel that each believes is necessary to operate under severe winter conditions, it will not provide the planning and coordination that may be necessary to ensure that ISO-NE's seasonal reliability criteria are satisfied. Thus, the ISO should evaluate whether it has seasonal planning needs for the winter that must be met to satisfy its overall reliability criteria. If so, we recommend that the ISO evaluate: a) the adequacy of the PFP framework in satisfying these needs, and b) the potential benefits and costs of market design changes that would complement PFP and facilitate the advance procurement of fuel needed to ensure fuel security.

### Market Operations during the 2017/18 Cold Snap

As the ISO considers options for ensuring sufficient resources are available to maintain reliability during periods of extreme natural gas scarcity, its overall strategy should also rely on providing efficient incentives through the day-ahead and real-time markets. This section of the report evaluates market operations during the severe weather conditions from the last week of December 2017 and early-January 2018.

Our evaluation revealed that prices did not always fully reflect the marginal cost of supply, which raises concerns about price formation and performance incentives that are evaluated in this section. In particular, we find that fuel inventory limitations are not well managed by the market, leading the ISO to take out-of-market actions, including making supplemental commitments and “posturing” resources. These actions indicate that the markets are not currently coordinating these limitations, and result in suboptimal pricing and incentives for suppliers to procure fuel and manage fuel inventories. Our evaluation also indicates:

- Production from oil-fired generators averaged just 48 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. This under-utilization was driven primarily by fuel inventory limitations and forced outages and deratings. This underscores the importance of efficient day-ahead and real-time price signals so that suppliers are properly motivated to procure fuel and maintain their units in a reliable condition.
- Pipeline gas-fired generation produced substantial output (averaging more than 2.4 GW each day) even though it appeared to be uneconomic on most days based on the day-ahead index prices. This raises potential price formation concerns, and likely occurred because suppliers scheduled gas in advance, expecting higher electricity prices. These suppliers sold significant quantities of gas after the scheduling window because it was more profitable than generating electricity at the relatively low energy prices.
- Thirty-minute operating reserve clearing prices were \$0 per MWh throughout the period, although the ISO committed an average of more than 400 MW to maintain adequate reserves. This inconsistency is attributable to significant fuel inventory limitations and gas supply constraints that would prevented the reserves from being deployed for

extended periods if large system contingencies had occurred. Implementing day-ahead operating reserve markets with reasonable deployment obligations will increase reserve prices, which will encourage suppliers to conserve limited fuel inventories in the short-term and increase incentives to schedule deliveries of fuel oil and LNG before the winter.

## Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism for ensuring that sufficient resources are procured to satisfy the planning reliability requirements of New England. The forward capacity market coordinates decisions to retire or mothball older resources with decisions to invest in new generation, demand response, and transmission. We evaluate potential market design improvements to facilitate competition in the auction and to enhance incentives for timely delivery of new resources.

### *Addressing Issues in the Minimum Offer Price Rules*

The purpose of the minimum offer price rule (“MOPR”) is to prevent uneconomic subsidized resources from artificially depressing market prices. This is important because these price effects will undermine the market’s ability to facilitate efficient long-term investment and retirement decisions by market participants. However, MOPR can also potentially interfere with competitive investment or artificially increase prices. Hence, it is important to ensure that MOPR is effective in addressing uneconomic entry while not interfering with economic entry. Based on our evaluation of the MOPR, we’ve identified three issues that we recommend the ISO address to improve its MOPR.

### *Conforming the MOPR to the Pay-for-Performance Framework*

Under the PFP rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essential engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages, relinquishing the performance payments in could have earned; or
- Do not sell capacity and earn the performance payment by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial

expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework. In addition, an uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. Therefore, we recommend the ISO make uneconomic units that were mitigated under the MOPR ineligible to receive performance payments.

### *Competitive Entry Exemption*

As noted above, the MOPR is intended to address uneconomic subsidized new resources that can artificially increase supply and depress prices. However, the current rules apply to all investment in new resources, including private investment in resources that are receiving no out-of-market subsidies. To the extent that the MOPR affects the offer prices submitted for such resources, it will interfere with competitive market-based investment.

Other RTOs have addressed this concern by implementing a “competitive entry exemption” to prevent the MOPR from interfering with private market-based investment.<sup>4</sup> Essentially, such a provision would exempt a new resource from the MOPR if it demonstrates that it is not receiving any direct subsidies or indirect subsidies via contract with a regulated entity.

### *Capping the Minimum Offer Price*

The MOPR is intended to prevent prices from reflecting artificial supply surpluses caused by uneconomic entry. There is no economic justification, however, for mitigating new resources when surplus capacity is zero or negative (i.e., new resources are needed to satisfy the system’s planning needs). In this case, a competitive and efficient market would facilitate entry at price close to the net CONE, and no price above this level can reasonably be considered depressed. Likewise, it is unreasonable for the MOPR raising prices substantially above net CONE. Unfortunately, this outcome would occur under ISO-NE’s current MOPR.

ISO-NE’s version of the MOPR always sets the offer floor at the new resource’s actual entry cost, even though it may be much higher than net CONE (currently near \$8 per kw-month). This may prevent state-sponsored resources that could satisfy a capacity need from clearing in the FCA and prompt the ISO to clear a conventional resource that is not needed (given the entry of the sponsored resource). This raises additional concerns under the ISO’s recently approved Competitive Auctions with Subsidized Policy Resources (“CASPR”) provisions because clearing unneeded conventional resources will compel the sponsored resources to pay lower-cost existing resources to retire.

Addressing this issue is straightforward, we recommend that ISO-NE cap the minimum offer price at net CONE. This will prevent artificial suppression of capacity prices below net CONE,

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<sup>4</sup> See NYISO’s Market Administration and Control Area Services Tariff section 23.4.5.7.9.

but would ameliorate the concerns described above. It would allow sponsored resources to enter at an offer equal to net CONE and displace new conventional resources offered at higher prices. To the extent that some sponsored resources clear in the FCA at or above net CONE, fewer lower-cost existing resources would be prompted to retire and fewer unneeded conventional new resources would enter, both of which would increase efficiency and lower costs for the regions' consumers.

### *Improving the Competitive Performance of the FCA*

In our previous Annual Market Reports, we evaluated the supply and demand in the FCA and concluded that:<sup>5</sup>

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.

In this report, we illustrate how a supplier facing limited competition could use available information to raise the clearing price above competitive levels under the current Descending Clock Auction.

Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides key information on other suppliers offers that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels. A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. Accordingly, we recommend the ISO transition from the DCA to a sealed-bid auction.

### *Delays in the Entry of New Resources*

In recent years, several new resources that obtained Capacity Supply Obligations ("CSOs") have been delayed and some have failed to deliver their capacity during the CCP. Consistent delays in delivery of resources has significant implications for market outcomes and efficiency, and affect other participants. Delayed new projects lower the prices in the FCA(s) in which they cleared, and as a result, FCA prices do not reflect the actual realized supply and demand, and the reliability of the system. In addition, other resources that obtained a CSO in the FCA with delayed resources would face additional performance related risks under the PFP framework. Since the forward capacity market framework is predicated on the value of explicitly

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<sup>5</sup> See Section V.A of our report on *2014 Assessment of the ISO New England Electricity Markets* and Section IV.A of *2015 Assessment of the ISO New England Electricity Markets*.

coordinating the entry of new resources through the market, evaluating and efficiently addressing the delay of new resources is essential.

Under the ISO's current tariff, the incentive to enter on time by the CCP includes:

- The requirement of a new resource to post a modest but increasing amount of security every year, which it forfeit if the project does not achieve commercial operation.
- If a new resource is able to retain its CSO before it is operational, it would potentially incur PFP costs for non-performance, but these are subject to stop loss provisions.
- The first two penalties are not commensurate with the costs these resources impose on the system, but the current tariff also includes requirements for the supplier to buy back the CSO bilaterally or through a mandatory demand bid submitted in ARA 3.<sup>6</sup>

The latter provisions are valuable because they require the supplier to incur a market-based settlement that reflecting the cost replacing the capacity. Hence, modifications to clearly require the resettlement or bilateral replacement of the CSO for the delayed resource is beneficial. However, changes to the rules for delayed resources need to consider the effect of stronger penalties on the offers of the new resources and the potential for higher capacity costs to consumers. New project developers are likely to incorporate the higher economic risks in their offers, which would lead to higher capacity prices. Further, the higher economic risks of delay encourage entities that may be opposed to new projects in legal or regulatory proceedings.

Ultimately, the benefit of forward capacity markets in coordinating the entry of new resources hinges in part on developers' ability to manage the risks related to the timing of development process. However, the legal and regulatory risks described above may largely be out of their control and the risk of such delays could become excessive. If this risk cannot be efficiently managed under the current forward capacity market framework, the ISO may benefit from transitioning to a prompt capacity market over the long term.

Under a prompt capacity market framework, where the auction is conducted immediately prior to the Capacity Commitment Period, the financial risks of construction delays would largely be borne by the developer and would likely be easier to manage. Additionally, the market prices received by all other market participants would reflect the actual supply and demand for capacity, so unexpected construction delays, load growth uncertainties, and unexpected resource failures/retirements would all be efficiently reflected in the capacity market prices. Expectations of future capacity and energy prices would govern participants' decisions to invest in new resources and retire existing resources.

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<sup>6</sup> Footprint Power updated its Commercial Operation Date in advance of ARA 3 for the 2017-2018 CCP, which substantially affected the outcomes of ARA 3 and the market-based penalties that would have been borne by Footprint Power. We did not agree with the ISO's interpretation of its Tariff in this case, but the ISO has since filed to modify and clarify this rule.

In addition, the FCM timeline was designed around conventional resources that typically take three years to develop. However, there are significant differences in the lead times of resources that are projected to enter the New England market in the coming decade. For instance, the lead time for developing solar resources is one to two years, while the development time for battery storage and demand response could be a few months. On the other hand, it appears that some conventional resources take significantly more than three years. As such, the one-size-fits-all FCM timeline might no longer be fully compatible with the timing of the investment decisions for new potential entrants to the New England market.

Therefore, while we support the ISO's efforts to develop improved rules and consequences for delayed resources, we also encourage the ISO to evaluate the potential benefits of a prompt market (relative to the current forward market) in light of the foregoing developments in New England.

### **Causes and Allocation of NCPC Charges**

Although the overall size of NCPC payments are small relative to the overall New England wholesale market, they raise a number of important concerns:

- They usually indicate that the markets do not fully reflect the needs of the system. Ultimately, this undermines the price signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term.
- NCPC payments can also distort suppliers' incentives. Thus, we evaluate the causes of NCPC payments to identify market improvements that would limit such distortions.
- NCPC payments tend to shift investment incentives away from flexible resources that will be increasingly valuable with the growth in intermittent renewable generation.

Our evaluation in this report shows that even with the improvements made in 2016, ISO-NE's uplift charges exceed the levels generated by most other RTOs. However, the ISO made substantial design improvements in early 2017 that should further reduce its NCPC, including allowing fast-start resources to set real-time energy prices and implementing interval-level (i.e., subhourly) settlements. Nonetheless, given the concerns that NCPC payments raise, we evaluate the causes of NCPC payments in order to identify potential market improvements.

#### ***Day-Ahead NCPC Charges***

In our assessment of day-ahead NCPC charges, we found that 42 percent was attributable to commitments for local second contingency protection, while 37 percent was attributable to commitments for the system-level 10-minute spinning reserve requirement. Although these requirements are reflected in the real-time market, there is no day-ahead market for operating

reserves. Thus, generation committed in the day-ahead market to satisfy these requirements, the resulting costs are not reflected efficiently in day-ahead prices. This process resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, three-quarters of which would not have been needed under a co-optimized energy and reserve market.<sup>7</sup>
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate that additional generation was committed to satisfy the 10-minute spinning reserve requirement in more than half of all hours in 2017, although this was not reflected in energy prices or spinning reserve prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

We make three recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves with energy in the day-ahead market (i.e., determine the lowest cost set of offers that simultaneously satisfies energy demand and operating reserve requirements).
- A day-ahead reserve market would also facilitate our recommendation to eliminate the Forward Reserve Market, which has resulted in inefficient economic signals and market costs.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

### *Real-Time NCPC Charges and Allocations*

In assessing the real-time NCPC charges, we found that 3 percent were for local reliability and 6 percent were for system level capacity requirements, while the vast majority were associated with inconsistencies between the output of economically scheduled generators and clearing prices in the real-time market.

We found that real-time deviations contribute to just 6 percent of the real-time NCPC, but they are allocated 55 percent of the NCPC charges. Hence, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. We recommend that the ISO modify the allocation of Economic NCPC charges to be more

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<sup>7</sup> Note, this includes LSCPR units that were committed by a constraint in the day-ahead commitment model, while the majority of LSCPR units in Boston were determined before the day-ahead market.



consistent with a “cost causation” principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

### Coordinated Transaction Scheduling

We find that the performance of the CTS process improved and the savings increased in 2017 because of improvements in price forecasts and increased CTS bid liquidity. However, forecast errors are still significant and limit the potential benefits of CTS. In particular, we find that a large share of unrealized benefits of CTS are from a small number of real-time intervals with relatively large (>\$20 per MWh) forecast errors.

We have performed a systematic evaluation to identify factors that contributed to price forecasting errors and find that:

- Errors in load forecasting and wind forecasting were the largest contributor in 2017, accounting for 23 percent of the price forecast errors.
- Differences in timing and ramp profiles between CTS and the dispatch system (“UDS”) were the second largest contributor, accounting for 22 percent of the forecast errors.
- Forced outages and poor dispatch performance by generators accounted for 15 percent of the forecast errors.
- Other external interfaces had schedule changes, transaction checkout failures, curtailments and other changes that accounted for 14 percent of the forecast.
- Other factors were significant collectively, but had relatively small impact individually.

Although there are significant opportunities to improve the performance of the CTS process, it is important to note that the CTS process with NYISO is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). The primary reason the other CTS processes have performed poorly is that the CTS are allocated substantially costs and transmission charges. We applaud ISO-NE and NYISO for agreeing not to charge such charges to their CTS transactions.

We will continue monitor the performance of CTS and evaluate factors that contribute to particularly large forecast errors because these account for a large share of the production cost inefficiencies. We have made similar recommendations to the NYISO on its forecasting.<sup>8</sup>

### Table of Recommendations

We make the following recommendations based on our assessments of the ISO-NE’s market performance. A number of these recommendations have been made previously and are now reflected in the ISO’s Wholesale Market Plan.

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<sup>8</sup> See Section XI.B in our 2017 State of Market Report for NYISO.

Recommendation	Wholesale Mkt Plan	High Benefit <sup>9</sup>	Feasible in ST <sup>10</sup>
<b>Reliability Commitments and NCPC Allocation</b>			
1. Modify allocation of “Economic” NCPC charges to make it consistent with a “cost causation” principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
<b>Reserve Markets</b>			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
<b>External Transactions</b>			
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓
<b>Capacity Market</b>			
6. Replace the descending clock auction with a sealed-bid auction and reduce the availability of information about qualified supply before the auction to improve competition in the FCA.			✓
7. Evaluate potential benefits of market changes that would complement PFP to ensure fuel security under severe winter conditions.		✓	
8. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.			✓

<sup>9</sup> Recommendation will likely produce considerable efficiency benefits.

<sup>10</sup> Complexity and required software modifications are likely limited.

## I. COMPETITIVE ASSESSMENT OF THE ENERGY MARKET

This section evaluates the competitive performance of the ISO-NE energy market in 2017. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.<sup>11</sup> We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

### A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by “derating” a generating unit (i.e., reducing the unit’s high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

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<sup>11</sup> See, e.g., Section VIII, *2013 Assessment of Electricity Markets in New England*, Potomac Economics.

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;<sup>12</sup> and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included the analyses in this report.

### B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index (“HHI”) - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are widely used in other industries, their usefulness is limited in electricity markets because they ignore the demand for electricity that substantially affects the competitiveness of the market.

The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the *ability* and *incentive* to raise prices in order to have market power. A supplier must also be able to foresee when it will be pivotal to exercise market power. In general, the more often a supplier is pivotal, the easier

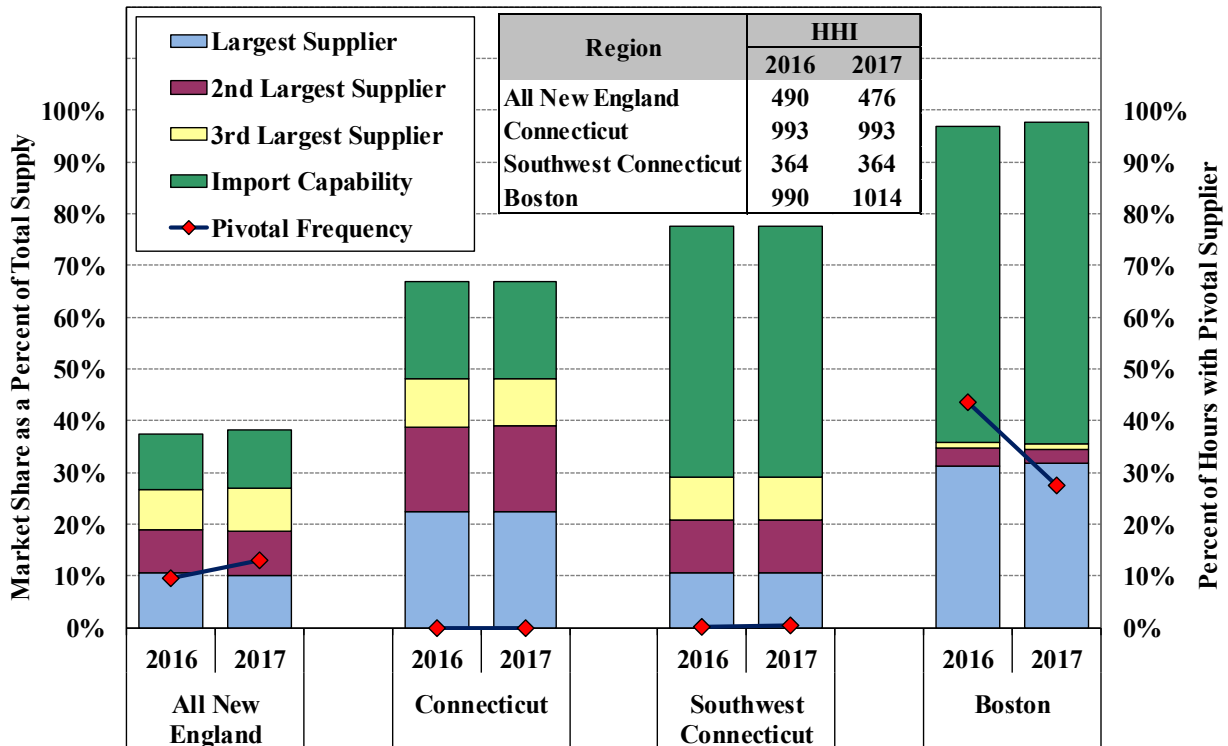
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<sup>12</sup> When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

for it to foresee circumstances when it can raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 1 shows the three structural market power indicators for each of the four regions in 2016 and 2017. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.<sup>13,14</sup> The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies. We assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

**Figure 1: Structural Market Power Indicators**  
2016 – 2017



<sup>13</sup> The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability (“SCC”), available at: <http://iso-ne.com/isoexpress/web/reports/operations/-/tree/season-claim-cap>. In this report, we use the generator summer capability in the July SCC reports from each year.

<sup>14</sup> The import capability shown is the transmission limit from each year’s Regional System Plan, available at: <http://iso-ne.com/system-planning/system-plans-studies/rsp>. The Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for the reserve zone.

Figure 1 indicates that market concentration has changed very little from 2016 to 2017 in each of the four regions. In all New England, the three largest suppliers were not changed from 2016 to 2017 and collectively accounted for roughly 27 percent of total supply (including import capability) in both years. Nonetheless, the generation portfolio of one of the three largest suppliers changed when it acquired over 1 GW of gas-fired combined-cycle capacity in early 2017 and retired its coal fleet in June 2017. However, the net change in size was relatively small. In each of the three reserve zones, the portfolios of its largest suppliers were virtually unchanged from 2016 to 2017.

There is variation in the number of suppliers with large market shares across the four areas. Boston has one supplier with a large market share of 32 percent, while Southwest Connecticut and all New England each have three suppliers with market shares of roughly 10 percent each. Import capability accounts for a significant share of total supply in each region (ranging from 11 percent in all New England to 62 percent in Boston), so the market concentration (measured by the HHI) was relatively low in all of the four areas.<sup>15</sup> However, this does not establish that there are no significant market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2017, which indicates that:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.5 percent) when a supplier was pivotal in 2017.
- In Boston, one supplier owned over 80 percent of the internal capacity, but was pivotal in just 28 percent of hours in 2017. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, at least one supplier was pivotal in 13 percent of hours in 2017.<sup>16</sup>

The pivotal frequency fell in Boston because of lower load levels in 2017 (down 2 percent from 2016), particularly in the summer season when it was down 8 percent from the prior summer. In addition, planned transmission outages were less frequent in the Boston area during 2017 following significant progress of the Greater Boston Reliability Project in 2016. This project increased import capability and caused the supplier to be pivotal less frequently in Boston.

However, the pivotal frequency rose modestly in all New England. This resulted from the portfolio changes for one of the largest suppliers mentioned above. Although the supplier's market share of total installed capacity fell modestly because of the changes, its share of generation increased in 2017. This increase was because its combined-cycle generation was

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<sup>15</sup> Antitrust agencies and the FERC consider markets with HHI levels above 1800 as highly concentrated for purposes of evaluating the competitive effects of mergers.

<sup>16</sup> The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM (see their 2017 SOM report, Section 3.7.3) primarily because of the following differences: (a) we assume no withholding from nuclear resources; (b) we do hourly pivotal supply evaluation (based on hourly averages) while the IMM does it at the UDS-level and counts an hour as a pivotal hour if a pivotal supplier exists in any of the UDS runs within that hour; and (c) headroom from units during their start-up and shut-down phases is not excluded from our evaluation.

usually less expensive than the coal-fired generation. This led the supplier to be pivotal slightly more frequently in 2017.

The results in Boston and all New England warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

### C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholding by using the following metrics:

- **Economic withholding:** we estimate an “output gap” for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between the unit’s capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.<sup>17</sup> This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.
- **Physical withholding:** we analyze short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources because it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

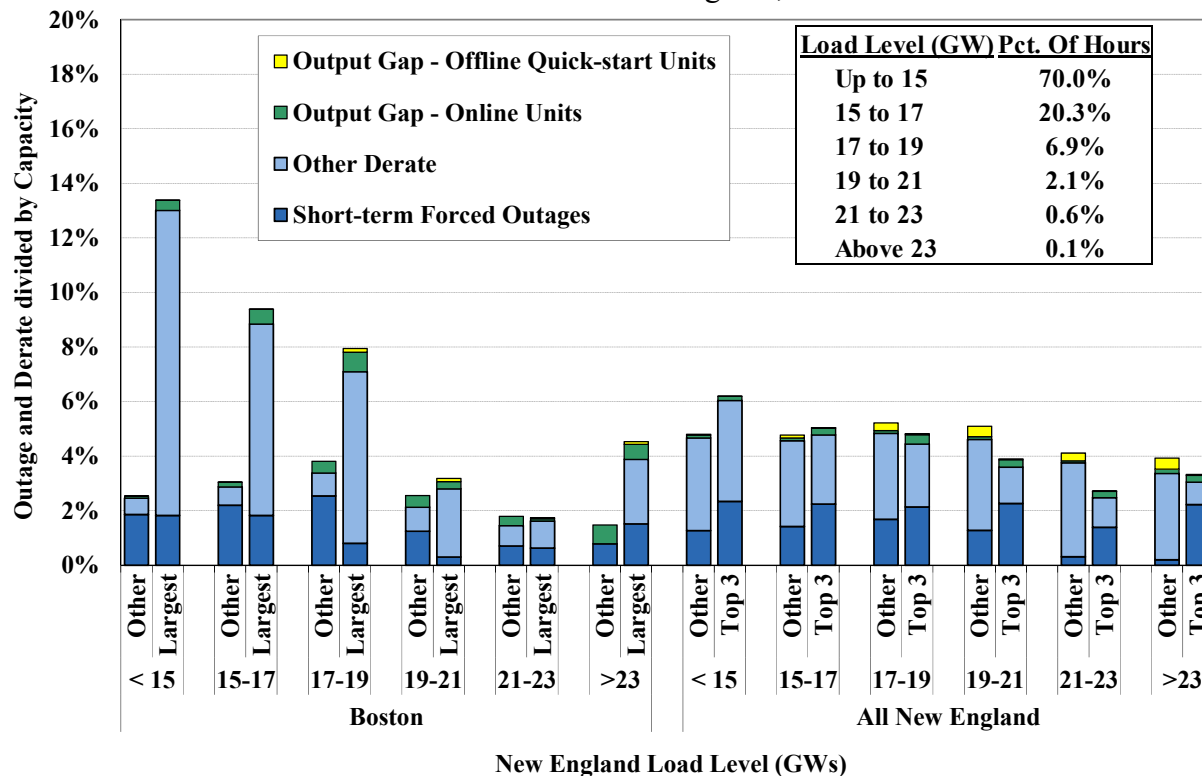
The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or physical deratings increase when factors prevail that increase suppliers’ ability and incentive to exercise market power. This allows us to test whether the output gap and physical deratings vary in a manner consistent with attempts to exercise market power.

Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 2 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for: a) offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and b) online units that can economically produce additional output. Our physical withholding analyses focus on: a) “Short-term Forced Outages” that typically last less than one week; and b) “Other Derates” that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. The “Other Derates” can be the result of ambient temperature changes or other legitimate factors.

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<sup>17</sup> To identify clearly economic output, the supply’s competitive cost must be less than the clearing price by more than a threshold amount - \$25 per MWh for energy and 25 percent for start-up and no load costs.

**Figure 2: Average Output Gap and Deratings by Load Level and Type of Supplier**  
Boston and All New England, 2017



The figure above shows the supplier’s output gap and physical deratings as a percentage of its portfolio size in Boston and all New England by load level. In Boston, we compare these statistics for the largest supplier to all other suppliers in the area. In all New England, we compare the three largest suppliers, who collectively owned roughly 30 percent of internal generating capacity in 2017, to all other suppliers.

In Boston, as was seen in the prior years, the amount of “Other Derate” in the largest supplier’s portfolio was notably higher during low load periods. This was because its combined-cycle capacity was frequently offered and operated in reduced configuration during these periods (e.g., overnight hours). This is generally efficient and does not raise significant competitive concerns..

Excluding the contributions of the “Other Derates” in Boston for the reasons described above, Figure 2 shows that the overall output gap and deratings were not significant as a share of the total capacity in both Boston and all New England. The total amount of output gap and deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest. In addition, the largest suppliers and other smaller suppliers in each region exhibited comparable levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding.



Overall, these results indicate that the energy market performed competitively in 2017 and did not raise significant concerns about withholding to raise market clearing prices.

#### D. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied:<sup>18</sup>

- Market-Wide Energy Mitigation ("ME") – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation ("MC") – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier.
- Constrained Area Energy Mitigation ("CAE") – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation ("CAC") – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation ("RC") – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation ("SUNL") – SUNL mitigation is applied to any resource that is committed in the market.
- Manual Dispatch Mitigation ("MDE") – MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels. This was first implemented in March 2017.

There are no impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these five categories. This is reasonable because this mitigation is only applied to uplift payments, which usually rise as offer prices rise, so, in essence, the conduct test is serving

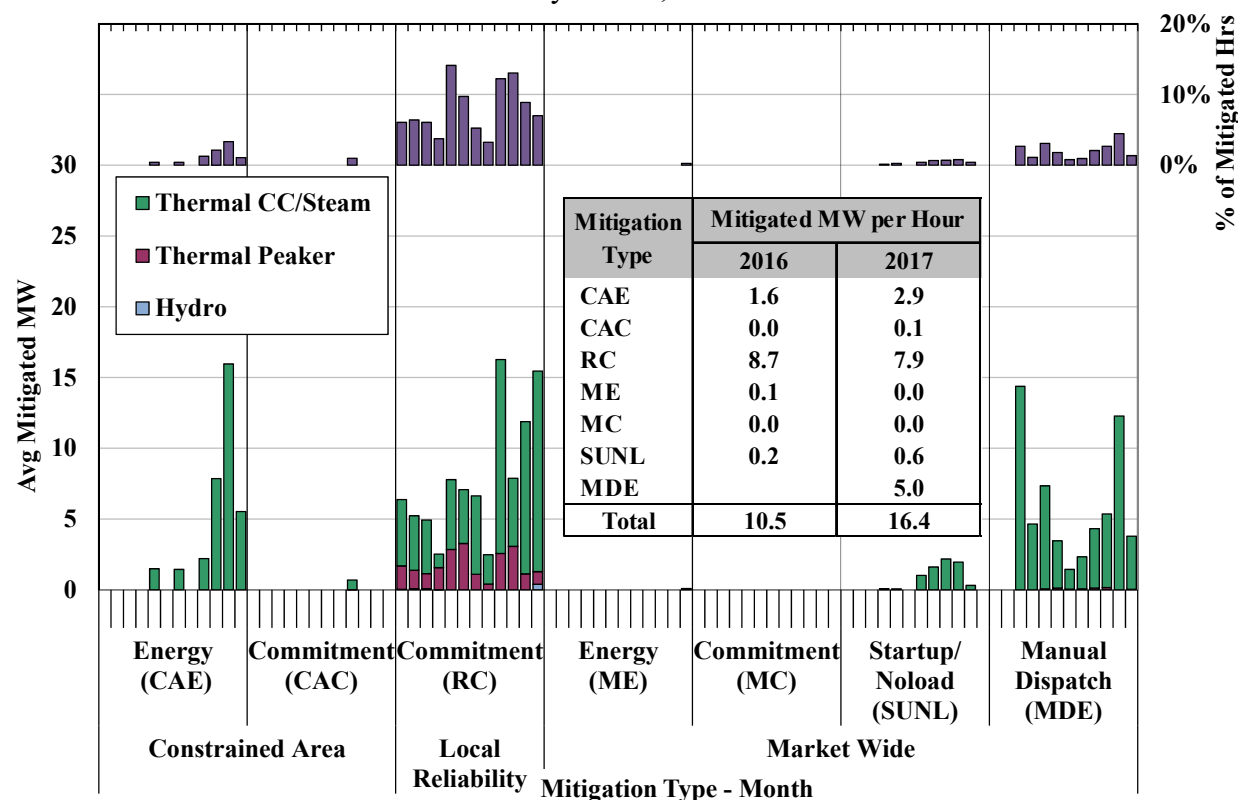
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<sup>18</sup> See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

as an impact test as well for these categories. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

Figure 3 examines the frequency and quantity of mitigation in the real-time energy market. Any mitigation changes made after the automated mitigation process were not included in this analysis. The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of hours in each month) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the annual average amount of mitigation for each mitigation type between 2016 and 2017.

**Figure 3: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type**  
By Month, 2017



Nearly 80 percent of all mitigation was for either local reliability commitment or manual dispatch energy. Both typically occurred more frequently during the shoulder months because of higher local reliability needs that were often caused by planned transmission outages. The high proportion of mitigation in these categories is expected because local reliability areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds.

In general, these two categories of mitigation only affect NCPC payments and have little impact on energy or ancillary service prices.

Although local reliability mitigation has the tightest threshold (10 percent) among all types of mitigation, it is not fully effective because suppliers sometimes have the latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a single-turbine configuration often do not offer in the single-turbine configuration when they are likely to be needed for local reliability. By offering in a multi-turbine configuration, these units receive higher NCPC payments. Likewise, generators are sometimes not required to burn the lowest-cost fuel – e.g., a substantial amount of NCPC was paid in 2017 to a unit that usually burned oil when natural gas was much less expensive. We discuss the two issues in more detail in Section V and continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

The amount of non-local-reliability mitigation has been low in recent years because the hourly offer market enhancement that was implemented in December 2014 has allowed suppliers to more accurately reflect their fuel costs (or opportunity costs) on an hourly basis and in a more timely manner. This has improved not only the competitiveness of supply offers but also the accuracy of the mitigation, particularly for:

- Energy limited hydro resources, whose costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are generally difficult to accurately reflect.
- Oil-fired resources, which become economic when gas prices rise above oil prices, but have limited on-site oil inventory. The suppliers may raise their offer prices to conserve the available oil in order to produce during the periods with potentially the highest LMPs.
- Gas-fired resources during periods of tight gas supply. Volatile natural gas prices, particularly in the winter, create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 2 pm on the prior day.

To supplement this improvement in offer flexibility, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy limitations. Appropriately recognizing these opportunity costs in resources' reference levels would reduce the potential for inappropriate mitigation of competitive offers and improve the overall efficiency of scheduling for fuel-limited resources. Furthermore, it would help address fuel security issues that ISO-NE faces by allowing generators to conserve fuel more effectively with their offers. We discuss the effects of fuel inventory limitations and other opportunity costs in more detail in Section III.

## E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns remain in Boston and in all New England under high-load conditions. However, based on the analyses of potential economic and physical withholding, we find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2017. In addition, the market power concerns in Boston will be further alleviated with the completion of the Greater Boston Reliability Project and when the Footprint Power combined-cycle plant comes into service in the near future.

In addition, we find that the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility. Hourly offers enable generators to modify their offers to reflect changes in their marginal costs and for the ISO to set reference levels that properly reflect these costs.

Nonetheless, there are two areas where the mitigation measures may not have been fully effective. The first relates to resources that are frequently committed for local reliability. Although the mitigation thresholds are tight for these resources, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. The second concern relates to generators with limited fuel inventories and other energy-limited resources. The ISO currently does not have procedures to allow these opportunity costs in reference levels, which may lead to inefficient scheduling of energy-limited resources. Hence, we recommend the ISO to consider changes that would address these concerns.

## II. FUEL SECURITY IN NEW ENGLAND

The New England region has seen entry of over 4 GW of new fuel-efficient conventional generation, while a comparable amount of nuclear, coal-fired, and older steam turbine capacity retired between the 2010/11 and 2020/21 Capacity Commitment Periods. While the region has seen net increases in capacity, its resource mix has become substantially more reliant on natural gas. The share of installed capacity resources relying on natural gas (gas-fired or dual-fuel) has risen from 47 percent to 63 percent over this timeframe.

The shift towards gas-fired generation is consistent with the long term investment signals we observed in the past few years for various types of resources. The region saw considerable new entry when the capacity prices were high. However, the net revenue projections for new and existing units have fallen sharply because of lower gas prices and lower capacity prices over the last three FCAs.

In particular, the long term economics of steam turbines have worsened significantly, given that the vast majority of their net revenue is from selling capacity. Hence, it is not surprising that 30 percent of the steam turbine capacity in service before 2010 has retired by 2018. Dual-fueled and gas-fired steam units that have higher-than-average going-forward costs (GFCs) or below-average performance are likely to consider retirement if the low capacity prices continue. In addition, the phase-in of the PFP capacity market rules from 2018 to 2024 presents challenges for steam units. PFP will shift more capacity revenue towards units that are frequently online or available to start within 30 minutes. As the potential penalties for non-performance increase, oil, coal and gas steam turbines will expect lower net revenues and greater economic risk.<sup>19</sup>

Overall, the New England fleet is shifting from older steam turbine capacity towards faster, more fuel-efficient combined cycle and peaking generation. However, the retirement of existing coal and oil-capable steam turbines raises concerns about the increasing reliance of the ISO-NE's system on natural gas. Furthermore, it is unclear whether gas-fired generation will be motivated to install and maintain the capability to operate on a back-up fuel.<sup>20</sup>

The recent trends in investment will increase New England's reliance on natural gas. Even as New England benefits from the low costs and environmental benefits of using natural gas, it will

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<sup>19</sup> The profitability of oil and coal steam turbines is likely to be worse than that of gas-fired units since natural gas is the cheaper fuel relative to coal and oil in the near future. In addition, coal units are also likely to incur additional environmental capex that existing gas-fired steam units may not require.

<sup>20</sup> Our 2016 net revenue analysis indicated that although the Winter Reliability Program ("WRP") provides units with sufficient revenues to maintain moderate inventories, the expected returns over the next three years are not (by themselves) sufficient for some units to build or retain the capability. See section II.B of our report *2016 Assessment of the ISO New England Electricity Markets*.

be important to consider fuel security, particularly during the winter when natural gas supplies are most limited.

ISO-NE has been concerned about its increasing reliance gas-fired generation for some time and published a study of its exposure to fuel security issues. This study was timely given the changes happening in the New England market. The analysis and recommendations in this section should complement the work by the ISO.

In this section, we evaluate how the available resource margins are expected to change during a winter cold spell in the coming years, accounting for expected changes in the resource mix. We then discuss the adequacy of ISO-NE's market rules for satisfying winter reliability needs.

### A. Impact of Trends in Resource Mix on Winter Reliability

As New England and other regions become increasingly reliant on natural gas, the reliability councils have become more concerned with the effects of fuel supply disruptions on the bulk power system reliability. However, the criteria for ensuring reliability during fuel supply disruptions are still evolving. Lacking an established set of methods for evaluating fuel security during winter conditions, we analyze the potential for a fuel supply shortage over a two-week period of severe winter weather. Specifically, the following analysis compares electric generators' demand for oil and gas to the available supply in the region for two winter seasons: 2014/15 and 2023/24.

- The winter 2014/15 scenario shows actual conditions observed in the second half of February 2015, which is representative of prolonged severe weather conditions that can produce unique reliability needs the ISO may need to plan to satisfy.<sup>21</sup>
- Since the winter of 2014/15, 2.4 GW of non-gas resources have retired. For the winter 2023/24 scenario, we assume that an additional 1.8 GW of non-gas resources (including the remaining coal-fired generation and roughly 1.3 GW of oil-fired capacity) will retire.<sup>22</sup>

For a period of two weeks of severe winter weather in each year/scenario, the following figure compares the supply and demand for oil and pipeline gas supply for generation. The demand indicated by the black lines in the figure includes total amount of fuel needed by oil and natural gas-fired generators to satisfy the system's load. This demand does not include other generator fuel types or the Mystic generators in Boston that have a direct source of LNG that does not go

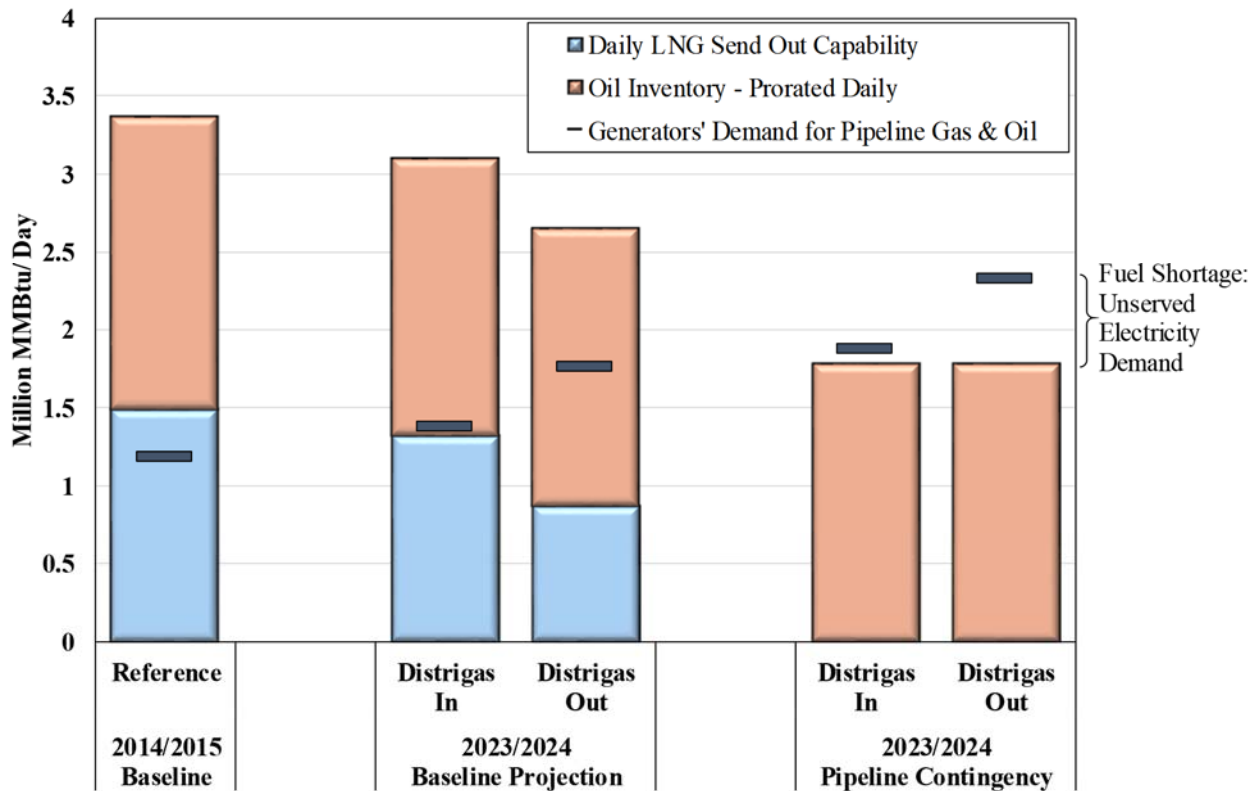
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<sup>21</sup> January and February 2015 had the most HDDs of any two month period, with February being the colder of the two months. Electricity generation from oil and LNG based resources exceeded natural gas generation by 18 percent during the second half of February. See <https://www.aga.org/knowledgecenter/facts-and-data/annual-statistics/weekly-and-monthly-statistics/heating-degree-day>.

<sup>22</sup> The 1.3 GW of oil-fired steam turbines submitted delist bids in recent FCAs. For the assumptions underlying Figure 4, see appendix of our *2016 Assessment of the ISO New England Electricity Markets*.

through the gas pipeline system. The figure shows potential LNG send out capability and prorated oil storage capacity. In all of these scenarios, the supply of gas imported on the interstate pipeline system does not show in the figure because it is fully utilized by core gas demand. Furthermore, core gas demand is assumed to take priority over electric generators, so the figure shows the remaining potential LNG available for generation after core demand is satisfied.<sup>23</sup> The amount by which the supply shown in the stacked bars exceeds the demand shown in the black lines the excess capacity. When the supply is less than the demand, this indicates a shortage that would prevent the ISO from serving all of the electric demand.

**Figure 4: Daily Potential Supply and Demand for Gas and Oil During Prolonged Winter Conditions<sup>24</sup>**



The owner of the Mystic units has announced plans to retire all units at the station, and the long-term economics of the Distrigas terminal are unclear if the Mystic units retire. Since the amount of LNG supply is a key variable for this analysis, we evaluated the impact of retiring the Distrigas terminal in a separate scenario. In this scenario, we remove the Mystic generation

<sup>23</sup> We include the capacities of Canaport, Distrigas and Exelerate facilities in the available LNG capability, so gas from Maritimes & Northeast pipeline is not included in the quantity of gas imported on the interstate pipeline system.

<sup>24</sup> Between Feb. 15-28, 2015, the total LNG send out exceeded the pipeline gas used by electric generators in New England. Accordingly, we reduced the total LNG capability by the difference between the two values.

(which causes the demand for oil and gas by other generators to rise) along with additional supply of LNG available from Distrigas beyond the amounts assumed to be consumed by the Mystic units. To evaluate the vulnerability of the system to fuel supply disruptions, the figure also shows an additional scenario where the amount of gas available is reduced as a result of a major outage on the Tennessee pipeline.<sup>25</sup>

The excess supply margin between the demand and potential supply of gas and oil is falling as the non-gas generators continue to retire and the core demand for natural gas grows. Hence, the share of total oil inventory and LNG capability needed to satisfy generators' demand is rising:

- In the baseline scenario, 35 percent in 2014/15 and 45 percent in 2023/24 of the total oil and LNG capability would be needed to satisfy generator's demand. This value rises to 67 percent in 2023/24 if Distrigas retires.
- In our Pipeline Contingency scenario in 2023/24, the potential supply of oil and gas would be five percent short of demand with Distrigas remaining in service and 31 percent short of the demand if Distrigas retires.

In the Pipeline Contingency scenarios, the LNG capability drops substantially because the LNG send-out capacity is assumed to be consumed by core demand, which generally has first call on the pipeline capacity that would be used to deliver the LNG. The 31 percent shortage in this scenario with Distrigas out would be a catastrophic shortage because it would translate to an average unserved load of roughly 2.5 GW over the two-week period. This is more than 10 percent of all load in New England.

Additionally, the conclusion that aggregate LNG capacity and fuel oil inventory capacity are theoretically sufficient to satisfy the generators' demand over a two week period of severe winter weather absent a pipeline contingency is based on an assumption that the LNG supply and oil inventories are fully utilized, which may not be the case because:

- Significant economic and physical constraints that may limit the availability of LNG below the daily capacities of the LNG terminals. In recent winters, total LNG send out has been far below the maximum capacity.<sup>26</sup>
- Limits on the individual unit tank sizes and run hours can reduce the total useable oil inventory. For instance, an oil tank will be unavailable to the market if the generator it supplies experiences a forced outage.
- Since the oil inventory shown corresponds to all tanks being full, the actually available inventory will reflect the portion of the tanks that suppliers find it economic to fill.

In the Baseline and Pipeline Contingency scenarios shown in Figure 4, LNG capacity would become pivotal for meeting generators' demand, even if the oil storage is fully utilized.

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<sup>25</sup> Pipeline contingency scenario assumes a loss of 1.32 Bcf/day in 2014/15 and 1.39 Bcf/day in the future.

<sup>26</sup> LNG deliveries must be arranged in advance. Physical delivery limitations and competing demands for LNG are constraints that can limit the available LNG once the severe winter conditions arrive.



Unfortunately, the ownership of facilities necessary to import LNG is relatively concentrated. This raises competitive concerns regarding the vulnerability of New England to the exercise of market power in the fuel markets. Such concerns are difficult or impossible for the ISO to address through modifications to its tariff.

Overall, this analysis reveals the essential role that both oil inventories and LNG play in ensuring fuel adequacy in winter. Any major reduction in the availability of either LNG or oil inventories could result in energy shortages in 2024. Unlike natural gas, the supply of these two fuels needs to be secured days to months in advance to ensure timely availability. This highlights the importance of advance planning and efficient incentives to ensure fuel adequacy during winter months. In particular, it will be increasingly important for ISO-NE to consider how to ensure reliability as the winter fuel supply margin tightens in the coming years. The following subsection discusses measures that could help ensure fuel security.

## **B. Discussion of Existing Mechanisms for Addressing Fuel Security Concerns**

The previous analysis shows that the winter fuel supply margin are likely to tighten considerably in the coming years. In the Baseline cold weather scenario shown for 2023/24, 45 percent of potential oil inventory and LNG capacity would be required to satisfy electricity demand, but such high utilization rates may require some form of coordination to ensure fuel security.

The ISO's WRP has enhanced fuel security in recent winters by arranging for oil-fired, LNG-fired, and DR resources to procure the necessary fuel or be otherwise available during a ten-day cold spell.<sup>27</sup> Thus, the WRP has helped the ISO fulfill two key objectives:

- Providing a financial incentive for generators to take the necessary steps to import fuel before the winter.
- Supports the ISO's seasonal reliability planning function by ensuring sufficient fuel will be available and by providing the ISO fuel procurement commitments from the generators.

However, a significant drawback to the WRP has been that it is not technology neutral, compensating only certain types of resources. For example, a nuclear unit is not compensated in a comparable manner even though it may be able to provide comparable fuel security as an oil-fired unit. This preference for specific fuel types distorts incentives for investment in other technologies that can satisfy ISO-NE's reliability needs.

The WRP is scheduled to end by June 2018 when the PFP program will become effective. The ISO had designed the PFP program to provide resources with strong incentives to perform during periods of shortage so that the WRP would no longer be necessary. However, PFP does not fully

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<sup>27</sup> See Appendix K of Market Rule 1 of the ISO Tariff.

address two issues. First, PFP provides strong incentives during operating reserve shortages, but recent experience during the 2017/18 cold snap highlights that the ISO can have surplus operating reserves in the real-time market even when generators are running very low on fuel.<sup>28</sup> Second, while PFP may provide strong incentives to generators when operating reserve shortages are likely, it will not provide the coordination that may be necessary to ensure that ISO-NE's seasonal fuel security needs are satisfied in the time horizon planning process.

### C. Conclusions and Recommendations

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. Over the decade from 2010/11 to 2021/22, about 4 GW of nuclear, oil and coal-fired capacity has retired or will retire, while the remaining oil and coal-fired capacity in New England will be economically challenged by falling capacity prices, the phase-in of PFP, and the entry of state-subsidized resources.

Although it appears that the oil inventory capacity and LNG import capability to New England are high enough to satisfy the demand for these fuels during a severe winter event, it would require very high utilization rates—far above any that have been observed in the past. Our fuel security assessment for a two-week severe winter period showed that while the system required 35 percent of this capability in the winter 2014/15, it is projected to require a very high percentage if the Distrigas terminal is retired. Additionally, even if this terminal does not retire, the demand for oil and gas will exceed the supply under a severe pipeline contingency in the 2023/24 cold snap scenario.

These trends raise questions about whether the current planning processes and market requirements are adequate to ensure fuel security by motivating generators to procure adequate fuel. Section III of this report shows that recent experience during the 2017/18 cold snap highlights that the ISO can have surplus operating reserves in the real-time market even when the New England generator fleet is running very low on fuel. Market design changes may be needed to ensure that generators have incentives to conserve limited fuel supplies. While ISO-NE's shortage pricing and PFP framework are designed to provide strong incentives for suppliers to be available during such conditions, these conditions may be difficult to predict and may need to be explicitly recognized in the ISO's planning processes to satisfy its one-in-ten reliability standard.

Hence, while PFP will provide strong incentives for generators to procure the fuel that each believes is necessary to operate under severe winter conditions, it will not provide the planning and coordination that may be necessary to ensure that ISO-NE's seasonal fuel security needs are satisfied. Thus, ISO should evaluate whether it has planning needs for the winter that must be met to satisfy its overall reliability criteria. If so, we recommend that the ISO evaluate: a) the adequacy of the PFP framework in satisfying these needs, and b) the potential benefits and costs

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<sup>28</sup> See our analysis of market operations during the 2017/18 cold snap in Section III.D.

of market design changes that would complement PFP and facilitate the advance procurement of the fuel to needed ensure fuel security.

In the absence of a market-based, technology-neutral solution to its fuel security concerns, the ISO recently filed tariff waiver requests that, if approved by the Commission, would enable the ISO to retain Mystic 8 and 9 units for the CCPs 2022/23 and 2023/24 through cost-of-service based contracts. While we recognize the immediate need for these contracts, we are concerned about designating a preference for one resource to the exclusion of others. Such actions will not be effective in addressing the fuel security concerns over the long term, and could undermine the market's ability to satisfy the region's fundamental reliability and cost objectives. Hence, we support the ISO in its efforts to work with its stakeholders in developing a market-based solution to the region's fuel security concerns.



### III. MARKET OPERATIONS DURING THE 2017/18 COLD SNAP

ISO-NE has recently attracted attention to the potential for severe reliability issues in periods of extreme natural gas scarcity.<sup>29</sup> Although the New England capacity market is designed to ensure sufficient installed capacity to maintain reliability during severe summer conditions, announced retirements of generating capacity have highlighted the fact that ISO-NE has no long-term market mechanism that is specifically designed to ensure that generators will have sufficient fuel to maintain reliability during severe winter conditions. The Winter Reliability Program (“WRP”) has been used for several years on a temporary basis to ensure generators have sufficient fuel inventories for the upcoming winter. This approach was not optimal, because it tended to provide revenue to resources that have higher costs to maintain firm fuel inventories but not to reward resources that are able to maintain firm fuel inventories at low or no cost.

In Section II, we recommend that ISO-NE consider whether it should establish planning requirements and associated capacity market changes to address its fuel security needs. Even with such changes, the ISO will continue to rely heavily on the day-ahead and real-time energy and ancillary services markets to provide incentives for generators to line-up their fuel supplies necessary to be available when needed.

Hence, day-ahead and real-time prices must accurately reflect the marginal cost of the supply needed to satisfy system needs in order to provide efficient incentives to procure fuel and perform reliably. Therefore, it is important to assess whether the day-ahead and real-time markets are functioning efficiently during severe winter weather conditions to ensure that suppliers have appropriate incentives to be available.

The period from late-December 2017 to early-January 2018 provided an opportunity to evaluate the performance of the energy and operating reserve markets under severe cold weather. Hence, in this section we evaluate:

- The fuel and electricity prices to determine whether they were consistent with the cost of supply needed to maintain reliability;
- Utilization of oil-fired and dual-fuel resources to identify factors that limited their availability;
- Production from gas-fired generation to determine whether electricity prices appropriately reflected the cost of fuel to maintain reliability; and
- The fuel availability of resources providing operating reserves to determine whether they were capable of sustained deployment in response to large supply contingencies.

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<sup>29</sup> See ISO-NE Comments on Grid Reliability and Resilience Pricing, Docket No. RM18-1-000, October 23, 2017; ISO-NE’s Operational Fuel-Security Analysis, January 17, 2018; ISO-NE’s filing, Seeking a Tariff Waiver for Retaining Mystic 8 and 9 Units, Docket No. ER18-1509-000, May 1, 2018.

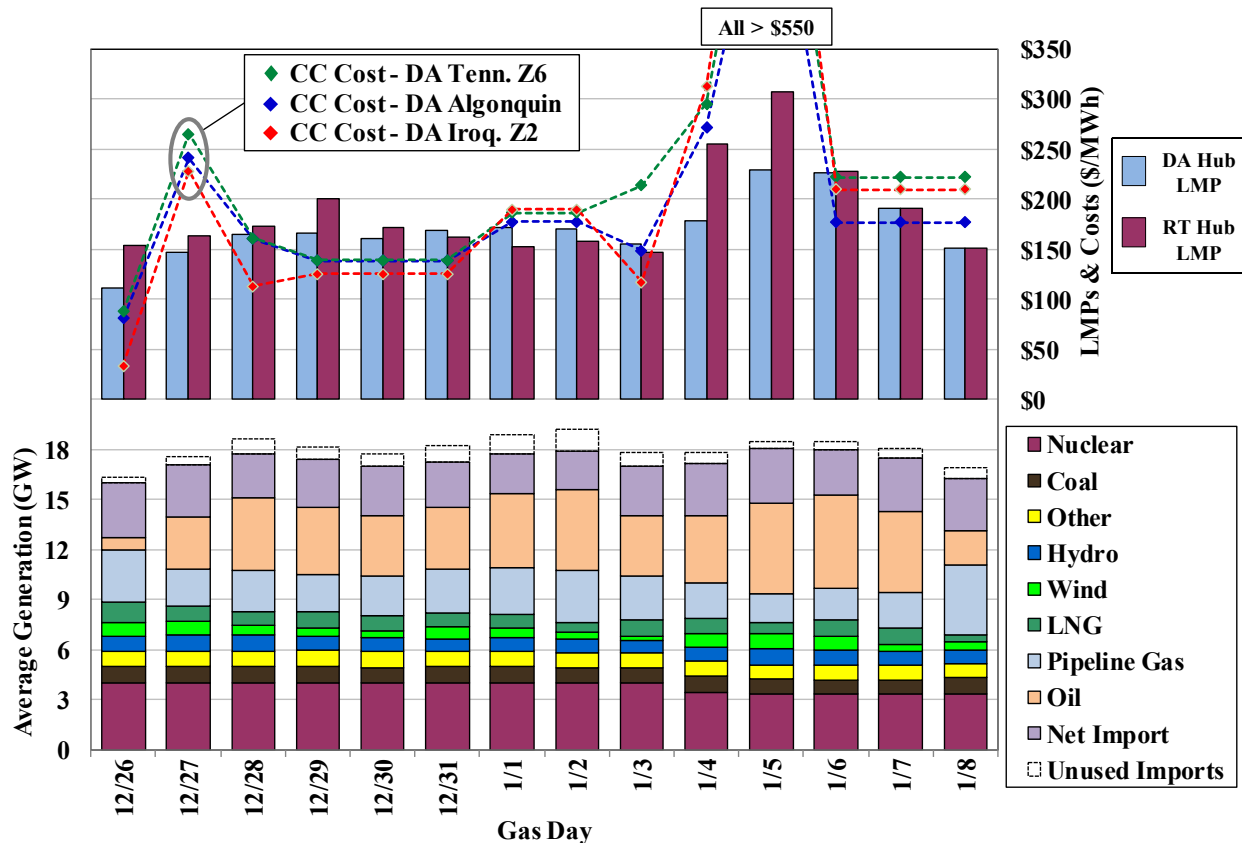
These analyses provide insight about how well the day-ahead and real-time markets coordinate the utilization of resources with limited fuel inventories and reward suppliers that invest in making their plants available with the necessary supply of fuel. Ultimately, these are two critical objectives of the day-ahead and real-time markets. Our conclusions and recommendations are provided at the end of the section.

### A. Evaluation of the Supply Mix and the Prices for Fuel and Electricity

This subsection shows sources of supply that New England relied upon during the cold snap to provide insight about whether prices reflected the marginal cost of supply. This is key in order for firms to have adequate incentives to import LNG, fuel oil, or electricity, and for investors to have efficient incentives to expand and/or maintain the capacity to import these products.

The bottom panel in Figure 5 shows the amount of generation supplied by each fuel type during the period by gas day and the net imports to New England and the amount of unused import capability. The top panel shows the average day-ahead and real-time LMPs at the New England Hub compared to the variable production cost of hypothetical combined cycle resources with heat rates of 7.0 MMBtu per MWh burning natural gas procured day ahead from Algonquin, Iroquois Z2, and Tennessee Z6.

**Figure 5: Generation by Fuel Type and Imports to New England**  
By Gas Day, December 26, 2017 to January 8, 2018



This evaluation provides several useful insights about market operations on the gas days with very tight gas market conditions (i.e., December 27 to January 7).

- All of the available nuclear, coal, other (wood/refuse), hydro, and wind was used to satisfy 6.3 to 7.7 GW (36 to 45 percent) of load on these days.
- LNG-fired generation exhibited a moderately-high (~50 percent) utilization rate, providing an average of 860 MW of supply on these days.
- Oil-fired generation exhibited abnormally high levels of production, averaging 4.3 GW, although this was far lower than the total winter seasonal claimed capability of 12.5 GW (i.e., an overall utilization rate of 34 percent).
- Pipeline-gas-fired generation was relatively consistent, providing an average of 2.4 GW of generation on these days. This includes three days (December 27 and January 4 & 5) when the day-ahead cost of gas from all three pipelines was substantially higher than electricity prices, even for a very fuel-efficient combined cycle unit.
- Imports were substantial, accounting for an average of 2.9 GW on these days. However, unused import capability averaged nearly 800 MW on these days. The ISO's concern about depletion of fuel inventories for internal generation caused it to impose out-of-market restrictions on exports to the NYISO on January 6.

These results raise three issues that are addressed later in this section:

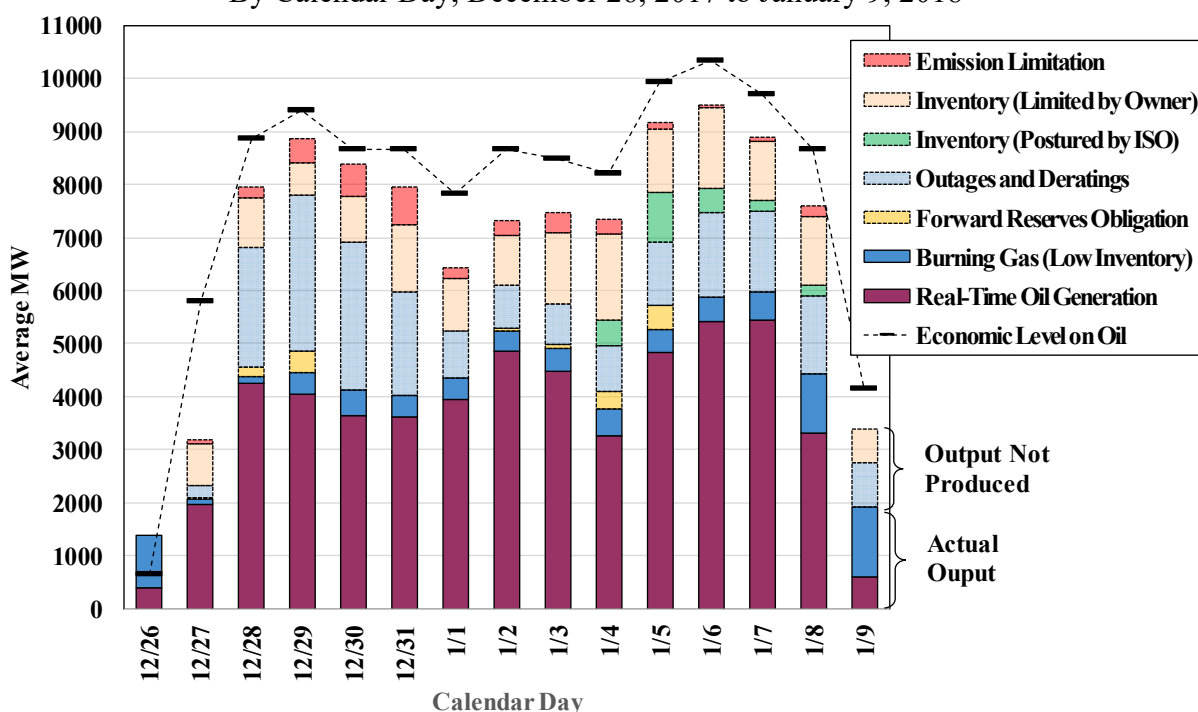
- First, oil-fired output averaged just 34 percent of the total claimed capability of oil-fired and dual-fuel units, and there were large quantities of economic oil-capable generation (assuming no inventory and emissions limitations) that was not utilized. Subsection B identifies factors that limited utilization of economic oil generation.
- Second, pipeline-gas-fired generation was relatively constant over this period even though there were at least three days when pipeline gas appeared to be substantially uneconomic based on the day-ahead index prices. For example, an average of 1.7 GW of gas-fired generation was running on January 5, when day-ahead LMPs averaged less than half of the costs of even the most efficient combined cycle based on the day-ahead gas costs on all three pipelines. Subsection C examines the use of these gas-fired resources and whether the cost of supply was appropriately reflected in LMPs.
- Third, clearing prices for thirty-minute operating reserves remained at \$0 per MWh throughout this period, even though concerns about the availability of operating reserves led the ISO to supplementally commit an average of 415 MW of capacity for reliability, primarily to satisfy operating reserves and fuel adequacy requirements. These commitments occur partly because the day-ahead and real-time markets do not provide adequate incentives for generators to conserve limited fuel supplies. Higher operating reserve prices would encourage suppliers to conserve limited fuel inventories in the short-term and increase incentives to line-up deliveries of fuel oil and LNG before winter in the long-term. We analyze the reasons for low operating reserve prices in Subsection D.

## B. Utilization of Oil-Fired and Dual-Fuel Capacity

This Subsection evaluates the use of oil-fired and dual-fuel capacity during this period. We estimate the amount of capacity that would have been economic based on the variable cost of generating from fuel oil, assuming no logistical, mechanical, or environmental limitations. For economic oil-capable resources, we identify factors that limited usage on each day during this period. This assessment provides key insight about how efficient markets should affect the availability of generation with firm fuel supply during periods of extreme natural gas scarcity.

Figure 6 shows our estimate of the amount of generation that would have been economic to burn oil based on day-ahead and real-time clearing prices on each day.<sup>30</sup> The figure shows this capacity in the following categories: actual oil-fired generation, actual gas-fired generation, and the amounts that were unavailable because of forced outages and deratings,<sup>31</sup> forward reserve obligations, emissions limitations, and fuel inventory limitations. Fuel inventory limitations are shown based on whether the generator was postured by the ISO or the generator limited its supply through the ordinary day-ahead and real-time scheduling processes.<sup>32</sup>

**Figure 6: Utilization of Oil-Fired and Dual-Fuel Capacity**  
By Calendar Day, December 26, 2017 to January 9, 2018



<sup>30</sup> We assume economic commitment of fast-start generation is done in accordance with real-time prices while economic commitment of slow-start generation is done in accordance with day-ahead prices.

<sup>31</sup> Non-forced outages and deratings were not significant during this period.

<sup>32</sup> For each generator whose economic oil-fired output exceeded its fuel inventory, we calculated the daily inventory limitation assuming the it will burn the same daily amount of oil for the remainder of the period.



Most of the gas-fired generation was produced by units that had oil inventory limitations, while a small amount was burned to comply with emissions limits. On each day, there was a small amount of capacity that appeared to be economic but which we were unable to categorize. (This is indicated by the difference between the top of the stacked bars and the estimated economic level on oil.)

For the calendar days of severe cold weather from December 28 to January 8, the figure shows that the average actual oil-fired production was about 48 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. To the extent that economic capacity was not used to burn oil, it was primarily because of:

- Forced outages and deratings, which led an average of 1.7 GW to be unavailable;
- Inventory-limited units, which accounted for an estimated 1.3 GW of unutilized capacity;
- Gas-fired production, which accounted for an average of 470 MW and was primarily done by combined cycle generators that were inventory-limited, although a portion was burned by steam turbines most likely to satisfy environmental limitations.

Although inventory limitations accounted for the majority of unutilized oil-fired output that appeared economic, forced outages were also a very significant factor. Ultimately, generators that have fuel while in a forced outage are no more valuable than generators without fuel. This highlights the importance of providing efficient price signals so that suppliers are appropriately motivated not only to procure fuel, but also to maintain their units in a reliable condition. In this regard, PFP will provide strong incentives to maintain units and reduce forced outages.

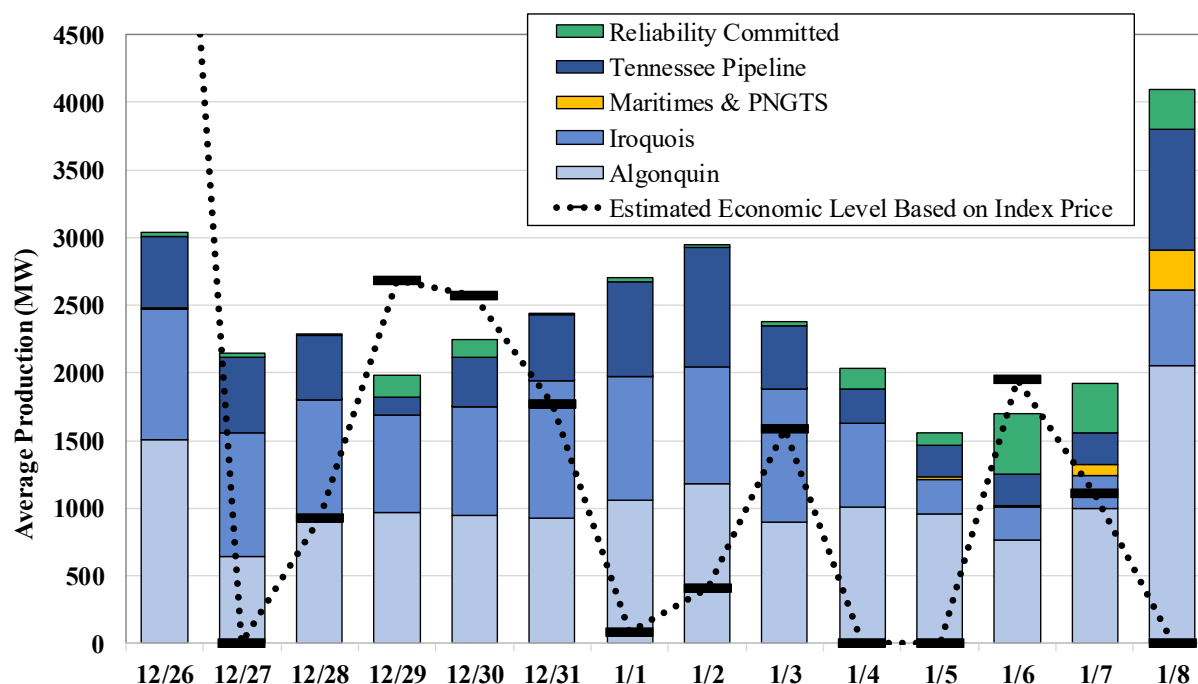
It is important to bear in mind that if oil-fired production was higher, it would have reduced LMPs and natural gas prices. If these price effects were considered, it would significantly reduce the estimated quantity of oil-fired generation that would have been economic over this period. This accounts for most of the large gap between the estimated economic level of oil-fired generation and the actual oil burn over this period.

### **C. Analysis of Production by Pipeline-Gas-Fired Generation**

This subsection evaluates the use of pipeline-gas-fired generation during this period to determine whether the marginal cost of these resources was efficiently reflected in clearing prices. This is important because it provides insight about whether the New England wholesale markets are providing the necessary signals to attract supply efficiently under tight operating conditions.

Figure 7 shows five categories of pipeline-gas-fired generation on each gas day: reliability commitments and dispatch, and four categories of economically scheduled generation shown based on which interstate pipeline serves the generator. This generation is shown relative to the amounts of generation that we estimate would have been economic to run using pipeline gas on each day based on the day-ahead index price for the generator.

**Figure 7: Production by Pipeline-Gas-Fired Generation versus Wholesale Prices**  
By Gas Day, December 26, 2017 to January 8, 2018



Of the generation that was economically committed to run on the gas days from the December 27 to January 7:

- 34 percent was delivered via the Iroquois pipeline;
- 45 percent was delivered via the Algonquin pipeline; and
- Just 20 percent was delivered via the Tennessee pipeline.

A relatively large share came from the Iroquois pipeline because, even though it serves only a small portion of western Connecticut, gas on Iroquois Zone 2 was priced at a discount relative to Algonquin and Tennessee Zone 6 on most days. The figure also shows that significantly more gas was burned by generators served by the Algonquin pipeline than by generators served by the Tennessee pipeline, which is consistent with the discount observed on Algonquin (relative to Tennessee Zone 6) on these days.

The figure shows that a small share (6 percent) of the pipeline-gas-fired generation resulted from out-of-market reliability commitments and dispatch by the operator, primarily on January 6<sup>th</sup> and 7<sup>th</sup>. The amount of gas-fired capacity that was committed for reliability was relatively small because it is normally difficult for a generator to line up natural gas in the time frame in which the ISO commits generation for reliability.

The vast majority (94 percent) of the pipeline-gas-fired generation was economically scheduled in the day-ahead market. However, most of this generation would appear to be uneconomic

based on the relevant day-ahead gas price index.<sup>33</sup> The amount of gas-fired generation was relatively consistent (averaging 2.4 GW) over this period, while the estimated economic level varied considerably (averaging just 1.1 GW).

Based on our review of natural gas pipeline scheduling information, we believe that several gas-fired generators purchased gas on these days anticipating that power prices would be higher. These generators burned most of the gas, but they also sold substantial quantities intraday, presumably because of the low LMPs in New England. Hence, these generators could have burned more gas, which would have allowed oil-fired generators to conserve fuel, but it was more profitable to sell it back to the gas market. This might be cause for concern, since it suggests that such generators will be reluctant to procure day-ahead natural gas in the future if they do not believe that LMPs will be sufficiently high for them to earn a profit from burning gas to sell electricity.

#### **D. Fuel Availability of Operating Reserve Capacity**

The ISO is required to maintain an amount of 30-minute operating reserve capacity equal to the largest supply contingency plus half of the second largest.<sup>34</sup> In addition, the ISO schedules 160 to 180 MW of replacement reserves above this requirement. The rules stipulate that 30-minute operating reserve units must be capable of generating for up to 60 minutes following a reserve deployment.

The 30-minute reserve requirement was devised to satisfy the short-term need for capacity following multiple large contingencies, but this requirement does not ensure sufficient reserves will be available if fuel is limited. For example, if two large supply sources with high capacity factors (e.g., a nuclear unit or the HVDC line from Quebec) were suddenly lost for an entire day, the ISO would need reserve capacity to generate for all 24 hours of the day. The ISO is required to plan in the day-ahead (and in other time frames) for the possible loss of up to one-and-a-half of the largest two supply contingencies. The ISO may effectively be short of reserves if they cannot be deployed for an extended period, even when 30-minute operating reserves are priced at \$0 per MWh and there is an apparent surplus in the real-time market.<sup>35</sup> Hence, there is a gap between the obligations of reserve providers and the planning needs of the RTO when the day-ahead market is procuring resources for the following day.

The ISO does not have a market mechanism to ensure that sufficient resources will be available with fuel on the next operating day to satisfy forecasted load and reserve requirements if supply contingencies require the reserves to be converted to energy from an extended period. Most of

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<sup>33</sup> For each generator, this assessment was based on the most relevant gas price index: Tennessee Zone 6, Iroquois Zone 2, Algonquin, or Dracut.

<sup>34</sup> See Northeast Power Coordinating Council, Directory #5, Reserve

<sup>35</sup> See ISO-NE Operating Procedure No. 8 – Operating Reserve and Regulation.

this requirement is satisfied by day-ahead energy obligations, but there is no day-ahead reserve market or forward reserve obligations to have sufficient fuel for continuous operation for an entire day. Consequently, the ISO must take out-of-market actions to ensure sufficient fuel resources will be available even if there appears to be excess operating reserves in the real-time market. Indeed, the ISO made commitments for reliability and imposed an out-of-market limit on exports to New York, while 30-minute reserves cleared at \$0 per MWh throughout the cold weather period.<sup>36</sup>

Figure 8 shows the average amount of operating reserves scheduled by the real-time market on each day compared to the operating reserve requirement (including the replacement reserve requirement). In addition, the figure shows the operating reserve amounts that would not have been available on each day if reserve providers were required to have sufficient fuel available to be fully converted to energy after the day-ahead market. This adjustment is shown for:

- Hydro and pumped storage units with limited inventories,
- Pipeline gas-fired units assuming that limited additional gas would be available for a sustained reserve deployment, and
- Oil-fired units with limited inventories.
- The figure also shows the average amount of capacity committed each day after the day-ahead market for reliability.

The figure shows that the actual amount of real-time scheduled reserves exceeded the total operating reserve requirement by an average of 2.9 GW on these days. However, the excess supply of reserves would fall to an average of:

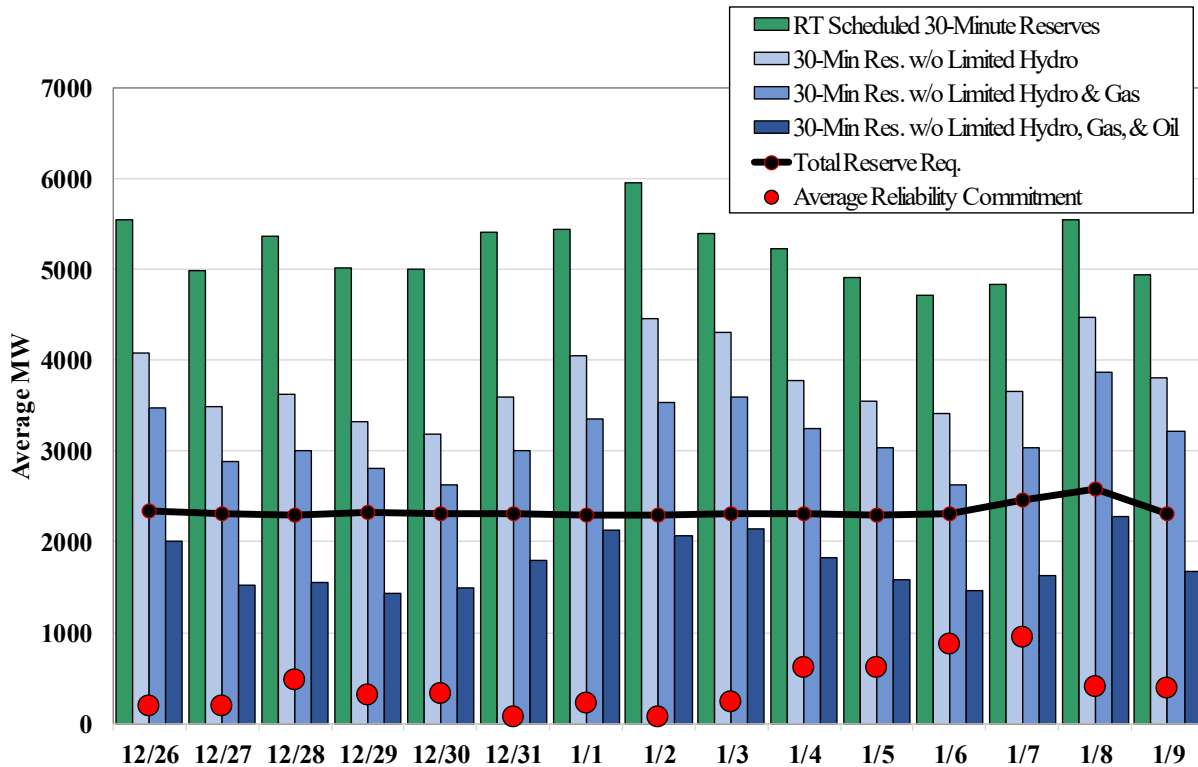
- 1.5 GW if the capacity of hydro and pumped storage units was discounted based on the amount of reserves that could be fully converted to energy over the period for which the reserves are scheduled; and to
- 0.8 GW if reserve capacity of pipeline gas-fired generators is assumed to not be convertible to energy; and to
- *Negative* 0.6 GW if the capacity of oil-fired units was discounted based on the amount of reserves that could be fully converted to energy.

This helps explain why the ISO committed an average of more than 400 MW of capacity to satisfy forecast load and maintain adequate reserves on these days.

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<sup>36</sup> See subsections A and C for discussions of reliability commitment and imposing CTS export limit during this cold period.

**Figure 8: Fuel Availability of Capacity Scheduled for All Operating Reserves**  
By Day, December 26, 2017 to January 9, 2018



This analysis highlights a large gap between the obligations of reserve providers to be available to produce energy for at least 60 minutes and the planning needs of the operators for fuel-secure generation. This is particularly important given that the ISO has planned to rely on the PFP mechanism to provide sufficient incentives for generators to procure the necessary fuel. The PFP mechanism assumes that generators will be motivated to buy fuel by the risk of 30-minute operating reserve shortages. However, the analysis above demonstrates that the system could have more than 2 GW of excess 30-minute reserves while the operators are making out-of-market commitments of generation to conserve fuel over a longer period of time.

We have recommended that the ISO implement ancillary services markets that are co-optimized with energy in the day-ahead market, and the ISO has expressed its support for doing this eventually. This recommendation has been driven primarily by the efficiency benefits and improved investment signals that would result under normal operating conditions. However, a day-ahead reserve market that is co-optimized with energy could also provide market incentives for generators to conserve their limited fuel inventories during tight natural gas supply conditions. When the ISO implements these markets, it should assess the specific obligations of reserve providers to be convertible to energy, since there is currently no such requirement.

Ultimately, it would be beneficial to have an operating reserve market that provides incentives for generators with firm fuel to conserve their stocks of fuel, which would help maximize

utilization of electricity import capability and internal pipeline gas-fired generation. Furthermore, enabling generators with firm fuel to sell operating reserves when economic would increase the returns to scheduling firm fuel deliveries and maintaining inventories.

### E. Conclusions and Recommendations

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. ISO-NE is considering options for procuring resources to maintain reliability during periods of extreme natural gas scarcity. Nonetheless, efficient day-ahead and real-time market performance should be part of any strategy to maintain reliability during winter conditions in an efficient manner that ensures the lowest possible cost to consumers.

This section of the report evaluates market operations during the severe weather conditions from the last week of December 2017 and early-January 2018. Our evaluation revealed that prices did not always fully reflect the marginal cost of supply, which raises concerns about price formation and performance incentives that are evaluated in this section. In particular, we find that fuel inventory limitations are not well managed by the market, leading the ISO to take out-of-market actions, including making supplemental commitments and “posturing” resources. These actions indicate that the markets are not currently coordinating these limitations, and result in suboptimal pricing and incentives for suppliers to procure fuel and manage fuel inventories. We also found:

- Production from oil-fired generators averaged just 48 percent of the capacity that we estimate would have been economic to burn oil on these days. This under-utilization was driven primarily by fuel inventory limitations and forced outages and deratings. This underscores the importance of day-ahead and real-time prices to efficiently motivate suppliers to procure fuel and maintain their units in a reliable condition, both of which are necessary for a generator to perform reliably during severe cold weather.
- Pipeline gas-fired generation produced substantial output that appeared to be uneconomic on most days based on the day-ahead index prices. This likely occurred because suppliers scheduled gas in advance, expecting higher electricity prices. These suppliers sold significant quantities of gas after the scheduling window because it was more profitable than generating electricity at the relatively low energy prices.
- Thirty-minute operating reserve clearing prices were \$0 per MWh throughout the period, although the ISO committed an average of more than 400 MW to maintain adequate reserves. This inconsistency is attributable to significant fuel inventory limitations and gas supply constraints that would prevented the reserves from being deployed for extended periods if large system contingencies had occurred. Day-ahead operating reserve markets with reasonable deployment obligations will increase reserve prices, which will encourage suppliers to conserve limited fuel inventories and schedule additional deliveries of fuel oil and LNG before the winter.

## IV. CAPACITY MARKET DESIGN ENHANCEMENTS

The purpose of the capacity market is to provide a market mechanism for ensuring that sufficient resources are procured to satisfy the planning reliability requirements of New England. The forward capacity market coordinates decisions to retire or mothball older resources with decisions to invest in new generation, demand response, and transmission. In this section, we evaluate potential market design improvements to facilitate competition in the auction and to enhance incentives for timely delivery of new resources. These improvements would enhance competition and improve the efficiency of price signals.

### A. Information and the Descending Clock Auction Format

The ISO uses a Descending Clock Auction (“DCA”) format (in conjunction with a market clearing engine) for its Forward Capacity Auction (“FCA”) to determine the capacity prices and to award Capacity Supply Obligations (“CSO”) for each resource. The DCA is conducted in a series of rounds that provide participating resources an opportunity to withdraw by submitting their offers between round-specific price levels. The DCA commences at a tariff-defined price as the starting price of Round 1, while the auctioneer specifies the ending price for Round 1. At the end of Round 1, the auctioneer determines the resources that are still in the auction, notifies the participants of the system-wide excess supply and establishes the ending price of the next round. This process repeats for additional rounds until the market clears.

The DCA format is sometimes touted over sealed bid formats because it provides auction participants with information about the value of a good. However, in the Forward Capacity Auction, sellers do not receive any information that may be useful in establishing a competitive capacity offer. Instead, the information learned through the auction process (in conjunction with pre-auction information) is primarily useful in determining when to leave the auction in order to set the highest price and receive the highest capacity revenue possible.<sup>37</sup> If a supplier uses this information to stop the auction and set the price at a level that is higher than its marginal cost of selling capacity, the resulting price is not fully competitive and efficient.

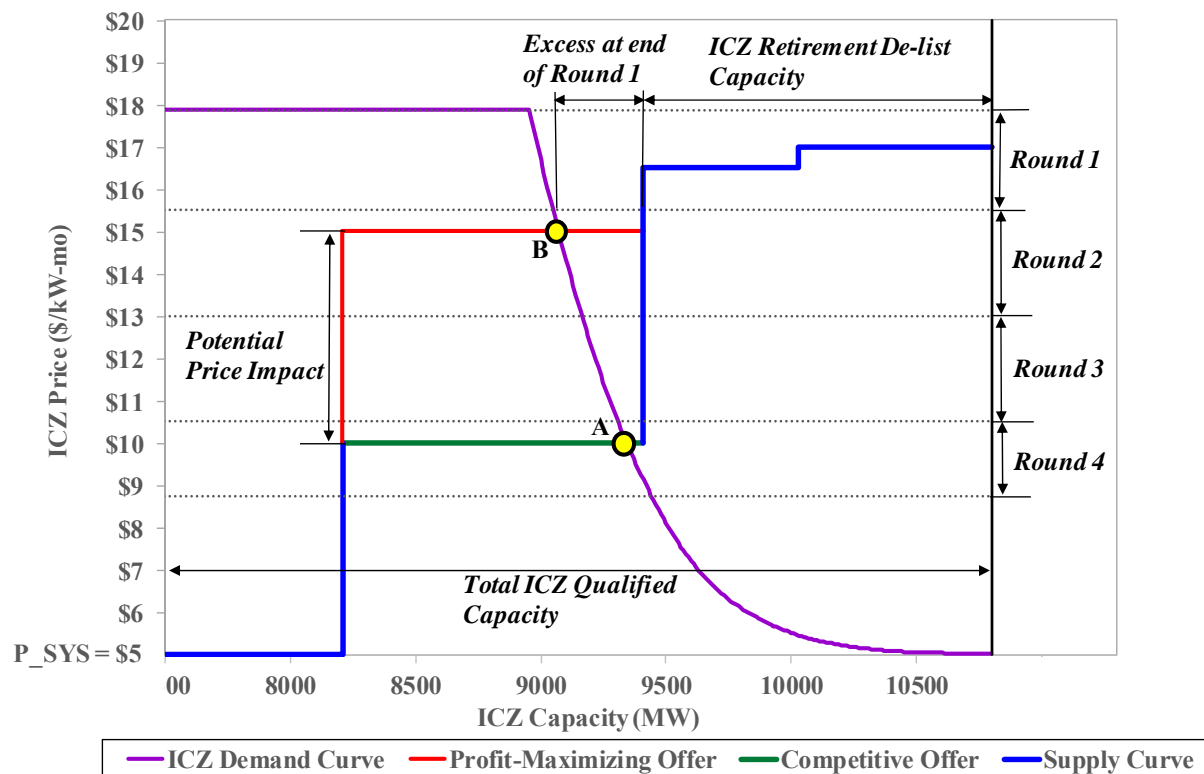
The ISO-NE clock auction provides the amount of excess system-wide supply at the end of each auction round. Hence, suppliers will know when they are pivotal market wide and, if the new resources are concentrated in a particular zone, this information will allow suppliers to infer how supply conditions may be changing in a particular zone. Figure 9 illustrates such a scenario where an individual supplier may be able to use the information from the DCA to increase prices in an Import Constrained Zone (“ICZ”).

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<sup>37</sup> For a discussion of information available to resources ahead of the FCA, see section IV of our report on *2015 Assessment of the ISO New England Electricity Markets*.

Figure 9 illustrates an FCA where a) there is significant excess supply system-wide, b) there are no retirements outside the ICZ, c) the supply conditions in ICZ are tight because of a large announced retirement, and d) there is only one new entrant in the ICZ.<sup>38</sup>

**Figure 9: Illustration of Incentives to Raise Prices using Information from the DCA<sup>39</sup>**



In such a scenario, the new resource in ICZ would be able to use the following information to raise the ICZ clearing price from A to B (see Figure 9):

- The total qualified capacity in the ICZ (from pre-auction information from the ISO's FERC filing and other sources), and hence the pre-auction excess supply in ICZ.<sup>40</sup>
- The quantity of capacity retiring in the ICZ (from the ISO's publications ahead of the auction).<sup>41</sup>
- The excess supply in the ICZ at the end of Round 1 (based on the information from the DCA process).<sup>42</sup>

<sup>38</sup> Under these conditions, the MRI of the resources outside the ICZ is likely to be much lower than those located in the ICZ. Hence, the impact of on the ICZ clearing price is likely to be minimal.

<sup>39</sup> This scenario assumes that the ROP clearing price will be \$5 per kW-month.

<sup>40</sup> See Table 7 in our report on *2015 Assessment of the ISO New England Electricity Markets*.

<sup>41</sup> See [www.iso-ne.com/static-assets/documents/2018/03/exit-de-list-nids-for-fca2022-23-load-zone.pdf](http://www.iso-ne.com/static-assets/documents/2018/03/exit-de-list-nids-for-fca2022-23-load-zone.pdf)

<sup>42</sup> In this scenario, since there are no retirements outside the ICZ, any reduction in the published system-wide excess at the end of Round 1 will be due to clearing the retirement delist bid in the ICZ.



Using the above information at the beginning of Round 2, the new resource would be able to deduce that it will be the marginal unit in the ICZ and that the ICZ could clear in the current round. Hence, it could increase its offer from a competitive level (as indicated by A in the figure) to a level just below the Round 2 starting price (as indicated by B), thus increasing the clearing price substantially without a significant risk of not clearing the auction.

Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides a key piece of information that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels. A sealed-bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. Accordingly, we recommend the ISO transition from the DCA to a sealed-bid auction.

## B. Delays in the Entry of New Resources

The FCA procures capacity more than three years in advance and the qualification process for new resources begins more than four years ahead of the delivery period. In recent years, a number of new resources that have obtained Capacity Supply Obligations ("CSOs") have been delayed and some have failed to deliver their capacity during the CCP. Large conventional new resources that have been delayed include Footprint Power, Burrillville Energy Center, and the Medway Peaker project.

In addition to customers not receiving the capacity they are paying to procure, consistent delays in the permitting and construction of resources has significant implications for market outcomes and efficiency. Delayed new projects lower the prices in the FCA(s) in which they clear and, as a result, FCA prices do not reflect the actual risk of non-reliability borne by the consumers. The suppression of FCA prices also impacts the long-term investment signals for new and existing capacity suppliers.<sup>43</sup> In addition, other resources that obtained a CSO in the FCA with delayed resources face additional performance-related risks under the PFP framework.

### *Consequences of Delays for the New Resource Developer*

The ISO's current tariff requires a new resource with a CSO to post an increasing amount of security every year, which the resource would forfeit if the project does not achieve commercial operation.<sup>44</sup> If a new resource is able to retain its CSO before it is operational, it would potentially incur PFP costs for non-performance. However, the PFP-related costs to delayed resources are subject to stop loss provisions that limit the downside for delayed resource

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<sup>43</sup> Although delayed projects could buy out of their CSO in an Annual Reconfiguration Auction ("ARA"), the FCA price effects would not be mitigated.

<sup>44</sup> See ISO New England Financial Assurance Policy VII.B.2.b.

developers. These two penalties alone for delayed resources are insufficient to provide efficient incentives for developers to avoid delays and are not commensurate with the costs these resources impose on other market participants.

However, the current tariff requires the participant to buy back its obligation bilaterally, or for the ISO to submit a mandatory demand bid to buy back the obligation in the Annual Reconfiguration Auction (“ARA 3”).<sup>45</sup> These provisions are valuable because they require the supplier to incur a market-based settlement that reflects the cost to the system of replacing the capacity.

However, when Footprint Power updated its Commercial Operation Date in advance of ARA 3 for the 2017-2018 Capacity Commitment Period, the ISO did not submit a mandatory demand bid for Footprint, so it was able to largely avoid this market-based penalty. Additionally, it caused the prices in ARA 3 to be understated at \$3.50 per kw-month. With a demand bid entered for this resource, the price in Boston would likely have cleared at almost \$16 per kw-month and the price outside of Boston would likely have cleared at \$7 per kw-month. Although we are unconvinced, the ISO believes it adhered to its tariff in this case.

Nonetheless, we do agree with the ISO that the tariff provisions governing delays in new resources could be improved. ISO-NE recently filed changes that would require it to submit a demand bid for a delayed new resource in the ARA3 only if resource is not in a position to achieve commercial operation in all twelve months of the CCP.<sup>46</sup> This weakens significantly the intended incentive for new resources to enter by the beginning of the CCP. However, the ISO is also working with its stakeholders to develop financial consequences that would be estimated using a daily charge rate that is tied to the replacement costs based on ARA3.<sup>47</sup> As a general matter, we support application of these penalties as long as they are commensurate with the impact that delayed resources have on the market.

However, any changes to the current rules for delayed resources need to consider the effect of stronger penalties on new resource offers and potential for higher capacity costs to consumers. New project developers are likely to incorporate the risk of any additional ISO penalties into their offers, thus leading to higher capacity prices. Furthermore, the imposition of strong penalties for delayed projects could strengthen entities that may be opposed to new projects in legal or regulatory proceedings. This could further increase the development risks for new projects in New England, some of which are very difficult to manage.

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<sup>45</sup> Market Rule 1, Section III 13.3.2.3 (a) and (b).

<sup>46</sup> Market Rule 1, Section III 13.3.2.3 (b).

<sup>47</sup> See June 6 2018 presentation by Ryan McCarthy to NEPOOL Markets Committee on *Delayed Commercial operation of New Resources*.

For instance, the permitting processes provide a forum for opposing new projects. New project developers often need to secure permits prior to the construction and the process can be time-intensive. Several agencies require demonstration of a public need for the project. Hence, while the permitting processes for most new projects are underway by the FCA, the permit decisions may not be known.<sup>48</sup> This requires the developer to bear the risk of a permit denial while participating in the FCA and taking on a CSO. The higher the potential costs of delay, the more incentive the project opponents have to cause delays in the permitting process that would slow or block entirely the entry of the new resource. Ultimately, this could result in higher offers prices, higher costs to consumers, and could deter new supply.

To illustrate the potential costs of delay to investors, we estimated the reduction in return on the equity to investors who sponsored a project that is based on the reference technology. We assume that:

- The FCA procured capacity equal to the ICR, and that the FCA price is \$8.03 per kW-month (i.e. the Net CONE);
- A resource that is delayed by a year is entered as a demand bid into the ARA, which cleared at \$10.32 per kW-month, and that the resource's equity investors will have to cover the interest expense for the delayed year;<sup>49</sup> and
- The Energy and Ancillary Services and PFP revenues earned by the unit equal those assumed in the most recent CONE and ORTP study.

Under these conditions, the overall return to equity holders for the entire economic life of the project would fall by up to 15.7 percent when the resource entry is delayed by just one year. Thus, the risk of incurring this cost is a significant consideration for developers participating in FCAs.

#### *Balancing Market Incentives to Enter with Penalties for Delays*

The theory of forward capacity markets coordinating the entry of new resources hinges in part on developers' ability to manage the risks related to the timing of development process. Appropriate market-based penalties in theory provide efficient incentives for developers to avoid delays. However, some delays may be out of their control and the risk of such delays could become excessive. It is unclear whether this issue could be effectively resolved in New England as long as it continues to operate a three-year forward capacity market.

A forward capacity procurement mechanism that specifies a delivery date requires new project developers *or* consumers to take considerable development risks. However, under a prompt

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<sup>48</sup> All large conventional new resources (>300 MW) that cleared in recent FCAs had permit applications that were pending at the time of the FCA.

<sup>49</sup> We estimate the ARA clearing price as the ROP price at a capacity level that is one unit of reference technology (i.e. 338 MW) less than the ICR.

capacity market framework, where the auction is conducted immediately prior to the Capacity Commitment Period, the financial risks of construction delays would largely be borne by the developer and would likely be easier to manage. Additionally, the market prices received by all other market participants would reflect the actual supply and demand for capacity, so unexpected construction delays, load growth uncertainties, and unexpected resource failures/retirements would all be efficiently reflected in the capacity market prices. Expectations of future capacity and energy prices would govern participants' decisions to invest in new resources and retire existing resources.

In addition, the FCM timeline was designed around conventional resources that typically take three years to develop. However, there are significant differences in the lead times of resources that are projected to enter the New England market in the coming decade. For instance, the lead time for developing solar resources is one to two years, while the development time for battery storage and demand response could be a few months. On the other hand, it appears that some conventional resources take significantly more than three years. As such, the one-size-fits-all FCM timeline might no longer be fully compatible with the timing of the investment decisions for new potential entrants to the New England market.

Therefore, while we support the ISO's efforts to develop improved rules and consequences for delayed resources, we also encourage the ISO to evaluate the potential benefits of a prompt market (relative to the current forward market) in light of the foregoing developments in New England.

### **C. Addressing Issues in the Minimum Offer Price Rules**

The purpose of the minimum offer price rule is to prevent uneconomic subsidized resources from artificially depressing market prices. This is important because these price effects will undermine the market's ability to facilitate efficient long-term investment and retirement decisions by market participants in New England.

Although they are extremely important, MOPR can also potentially interfere with competitive investment or artificially increase prices. Hence, it is very important that the MOPR be carefully designed to be effective in addressing uneconomic entry while not interfering with economic entry.

In evaluating the MOPR, it is important to recognize how it will be modified under the recently approved Competitive Auctions with Subsidized Policy Resources ("CASPR"). This proposal attempts to accommodate state-sponsored resources by coordinating their entry with retirements of existing resources to minimize artificial capacity surpluses. Under CASPR, the FCA would be conducted in two passes of the auction:

- Initial FCA auction: Includes all of the subsidized resources subject to the MOPR per the current rules, with other existing and new resources clearing as normal; and

- Substitution auction: Allows the subsidized resources that did not clear in the first pass to purchase the initial capacity obligation from an existing resource submitting a retirement delist bid that cleared in the initial FCA auction.

Based on our evaluation of the MOPR, we've identified three issues that we recommend the ISO address to improve its MOPR. The NYISO was the first ISO to implement MOPR rules. Two of the issues discussed below in the following subsections were identified and addressed by NYISO in a manner that is comparable to our recommended solution.

#### *Conforming the MOPR to the Pay-for-Performance Framework*

Under the pay for performance rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essentially engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages. Hence, the supplier relinquishes the performance payments it could have earned and will be charged the performance rate as a penalty; or
- Do not sell capacity and earn the performance payment by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework.

Further the uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. A rational offer for capacity under PFP will include the foregone performance payments. Because the uneconomic entrant will reduce the expected frequency of shortages, it should reduce the offer prices from the capacity suppliers in the region and lower capacity prices. Therefore, we would recommend the ISO making uneconomic units that were mitigated under the MOPR ineligible to receive performance payments.

#### *Competitive Entry Exemption*

As noted above, the MOPR is intended to address uneconomic subsidized new resources that can artificially increase supply and depress prices. However, the current rules apply to all investment in new resources, including private investment in resources that are receiving no out-of-market

subsidies. To the extent that the MOPR affects the offer prices submitted for such resources, it will interfere with competitive market-based investment.

Other RTOs have addressed this concern by implementing a “competitive entry exemption” to prevent the MOPR from interfering with private market-based investment.<sup>50</sup> Essentially, such a provision would exempt a new resource from the MOPR review by the IMM if it demonstrates that it is not receiving any direct subsidies or indirect subsidies via contract with a regulated entity.

### *Capping the Minimum Offer Price*

The MOPR is intended to prevent prices from reflecting artificial supply surpluses caused by uneconomic entry. There is no economic justification, however, for mitigating new resources when surplus capacity is zero or negative (i.e., new resources are needed to satisfy the system’s planning needs). In this case, a competitive and efficient market would facilitate entry at price close to the net CONE. Hence, prices cannot be considered depressed unless the uneconomic entry results in prices less than net CONE. Likewise, it is unreasonable for the MOPR to prevent resources from clearing and raising prices substantially above net CONE under these conditions. Unfortunately, this outcome would occur under ISO-NE’s current MOPR.

The issue under the ISO’s version of the MOPR is that the offer floor is always set at the new resource’s actual entry cost, even though it may be much higher than net CONE (currently near \$8 per kw-month). For example, if a new resource is needed and the need is satisfied by a sponsored resource that is mitigated to \$13 per kw-month, it will set the price at \$13 per kw-month even though this is substantially higher than net CONE.

This issue with the MOPR raises additional concerns under the CASPR proposal that we outlined in our protest of the CASPR rules. Namely, mitigating sponsored resources that are entering and sufficient to satisfy any incremental capacity needs at an offer floor substantially above net CONE can cause unneeded and inefficient new conventional resources to enter. Under the CASPR proposal, once the new conventional resource clears in Pass 1 of the FCA, it cannot be displaced in the substitution auction. This is a design flaw that the Commission did not address in approving the CASPR provisions, but it is exacerbated by this MOPR rule.

Addressing this issue is straightforward, we recommend that ISO-NE cap the minimum offer price at net CONE. This prevent artificial suppression of capacity prices below net CONE, but would ameliorate the concerns described above. For example, it would reduce (but not eliminate) the effects of the CASPR design flaw by allowing sponsored resources to enter at an offer equal to net CONE and displace new conventional resources offered higher than this level. To the extent that some sponsored resources could clear in Pass 1 of the FCA, the reliance of the

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<sup>50</sup> See NYISO’s Market Administration and Control Area Services Tariff section 23.4.5.7.9.

substitution auction would be reduced. Ultimately, fewer lower-cost existing resources would be prompted to retire and fewer unneeded conventional new resources would enter, both of which would increase efficiency and lower costs for the regions' consumers.

#### **D. Conclusions and Recommendations**

In this section, we evaluated three market design issues that could have significant implications for the efficiency of the FCM. First, the DCA process could provide information to participants of the auction that they could use to raise prices above competitive levels under certain conditions. Hence, we recommend the ISO transition to a sealed-bid auction format for the FCA and reduce the amount of information that is published on the quantity of qualified capacity.

Second, we believe that the current penalty provisions are not optimal for addressing delays in delivery of new resources that possess a CSO. We support the ISO strengthening the requirement for new suppliers to buy back their CSO. However, in a forward market construct, we believe that it would be challenging to strike a balance between providing appropriate incentives for timely delivery and potentially deterring new entry through greater penalty and regulatory/ legal risks. Accordingly, we recommend the ISO consider the benefits of a prompt market relative to a forward market, given the increasing development risks for conventional resources and potential misalignment of the FCM timeline with the investment decisions for new types of resources.

Third, the MOPR in New England will continue to play a pivotal role in determining the market prices and affecting entry and exit decisions. We discuss three significant concerns with ISO-NE's version of the MOPR that should be addressed to ensure that it does not cause the FCM to produce inefficient outcomes and costs that must be borne by customers in New England.





## V. CAUSES AND ALLOCATION OF NCPC CHARGES

When resources are scheduled at clearing prices that are not sufficient for them to recover their full as-bid costs, the revenue shortfall is covered with an NCPC payment. Although the overall size of NCPC payments are small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when the market requirements are not in full alignment with the reliability needs of the system or market clearing prices are otherwise not fully efficient. Additionally, sustained levels of NCPC can distort the market participants' incentives. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

Like other wholesale electricity markets, the ISO-NE uses a uniform price auction to coordinate the scheduling decisions of many sellers. The profit-maximizing offer of a competitive supplier in a uniform price auction is its short-run marginal cost, which it can determine without having to make predictions of market clearing prices. The ISO can optimize its commitment and dispatch based on such offers to minimize the costs of satisfying system demand and reserve requirements. In some cases, however, NCPC payments provide incentives for suppliers to raise their offer prices above short-run marginal cost to increase their payments. For example, suppliers that frequently receive NCPC payments may have incentives to deliberately increase their costs by procuring more expensive fuel.

Most NCPC payments occur when an operating requirement is not fully reflected in the market's requirements and must therefore be satisfied by scheduling a resource outside of the market. The cost of this action will be reflected in NCPC payments rather than in market-clearing prices. Ultimately, this undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term.

Additionally, intermittent renewable generation will likely become more prevalent over the coming decade, which will increase the value of flexible resources. NCPC payments do not provide efficient incentives because they generally reward resources for being high-cost and inflexible. Hence, NCPC payments tend to shift investment incentives away from flexible resources at locations that would bolster transmission security and reliability.

This section evaluates the causes of NCPC charges in 2017 and discusses implications for market efficiency, divided into subsections that address the following topics:

- Comparison of uplift charges and allocations in ISO-NE versus other markets;
- Primary drivers of day-ahead NCPC charges;
- Local second contingency protection requirements that lead to day-ahead NCPC charges;
- System-level operating reserve requirements that lead to day-ahead NCPC charges;
- Discussion of significant drivers of real-time NCPC charges; and
- Summary of conclusions and recommendations.

### A. Cross-Market Comparison of Uplift Charges and Cost Allocation

Before discussing the causes and implications of various classes of NCPC costs (generally referred to as “uplift” costs industry-wide), it is useful to place ISO-NE’s NCPC charges in context. Table 1 shows its total day-ahead and real-time NCPC charges over the past three years, and the comparable 2017 uplift charges for the NYISO and the MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

**Table 1: Summary of Uplift by RTO**

		ISO-NE			NYISO	MISO
		2015	2016	2017	2017	2017
<b>Real-Time Uplift</b>						
<b>Total</b>	<b>Local Reliability (\$M)</b>	\$25	\$1	\$1	\$5	\$3
	<b>Market-Wide (\$M)</b>	\$58	\$27	\$23	\$9	\$61
<b>Per MWh of Load</b>	<b>Local Reliability (\$/MWh)</b>	\$0.19	\$0.01	\$0.01	\$0.03	\$0.01
	<b>Market-Wide (\$/MWh)</b>	\$0.45	\$0.22	\$0.19	\$0.06	\$0.09
<b>Day-Ahead Uplift</b>						
<b>Total</b>	<b>Local Reliability (\$M)</b>	\$24	\$31	\$15	\$21	\$25
	<b>Market-Wide (\$M)</b>	\$12	\$13	\$13	\$3	\$15
<b>Per MWh of Load</b>	<b>Local Reliability (\$/MWh)</b>	\$0.18	\$0.25	\$0.12	\$0.13	\$0.04
	<b>Market-Wide (\$/MWh)</b>	\$0.10	\$0.10	\$0.11	\$0.02	\$0.02
<b>Total Uplift</b>						
<b>Total</b>	<b>Local Reliability (\$M)</b>	\$48	\$33	\$16	\$26	\$28
	<b>Market-Wide (\$M)</b>	\$70	\$40	\$36	\$12	\$76
<b>Per MWh of Load</b>	<b>Local Reliability (\$/MWh)</b>	<b>\$0.38</b>	<b>\$0.26</b>	<b>\$0.13</b>	<b>\$0.17</b>	<b>\$0.04</b>
	<b>Market-Wide (\$/MWh)</b>	<b>\$0.55</b>	<b>\$0.32</b>	<b>\$0.29</b>	<b>\$0.08</b>	<b>\$0.12</b>
	<b>All Uplift (\$/MWh)</b>	<b>\$0.92</b>	<b>\$0.58</b>	<b>\$0.42</b>	<b>\$0.24</b>	<b>\$0.16</b>

The table shows that ISO-NE made substantial progress in reducing its NCPC from 2015 to 2017 by:

- Eliminating a flaw in its NCPC payment rules in February 2016, which had previously allowed resources whose costs were fully covered in the day-ahead market to receive additional real-time NCPC payments;
- Implementing a fast-start pricing logic in March 2017 that enabled fast-start resources to set prices that may otherwise require uplift payments to cover their as-bid costs; and
- Settling real-time market outcomes at the five-minute interval level beginning March 2017 (previously at the hourly level), which tends to lower real-time uplift charges for units that follow ISO’s dispatch instructions.

However, the table shows that ISO-NE still incurs substantially more uplift costs, adjusted for its size, than the other two markets. Its total NCPC costs per MWh was roughly double the costs

incurred by NYISO or MISO in 2017. This was partly because ISO-NE's fuel costs tended to be higher than the other RTO's, which generally led to higher required make-whole payments. In addition, ISO-NE incurred a significant amount of uplift to satisfy the local second contingency protection requirements. This was comparable to the uplift costs incurred in the NYISO market, but much lower than in this class of uplift in the MISO market. The NCPC uplift charges that resulted from non-local reasons (i.e., in the market-wide category) were substantially larger than the levels (in terms of cost per MWh) observed in the NYISO and the MISO. We discuss the main drivers of these uplifts in Subsections B and E.

ISO-NE allocated most of the real-time NCPC charges to real-time deviations, including virtual transactions. In organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets. However, we have observed relatively low levels of virtual trading in the ISO-NE compared to other markets we monitor, which we attribute primarily to the allocation of large NCPC charges (per MWh) to virtual transactions, virtual load in particular.

Table 2 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The gross profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

**Table 2: Scheduled Virtual Transaction Volumes and Profitability**

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2015	1.4%	\$0.55	1.8%	\$1.98	\$2.92
	2016	1.3%	\$1.70	2.0%	\$1.94	\$1.25
	2017	2.2%	\$1.98	3.6%	\$2.71	\$0.81
NYISO	2017	5.2%	-\$0.30	14.5%	\$0.43	< \$0.1
MISO	2017	9.1%	\$0.42	9.3%	\$1.20	\$0.52

Table 2 shows that virtual trading generally improved price convergence between the day-ahead and real-time markets in ISO-NE because it was generally profitable. The average volume of cleared virtual transactions increased from 2015 to 2017, which was due largely to reduced uplift charges to real-time deviations over the period. In spite of the increase, the virtual trading levels were still substantially lower than the levels observed in both the NYISO and the MISO.

Most of the differences shown in the table between ISO-NE and the other RTOs continue to be attributed to ISO-NE's NCPC allocation methodology, which raises significant concerns. The

NCPC charges remain higher and more uncertain than the charges imposed by the other RTOs. This provides a substantial disincentive for firms to engage in virtual trading because virtual profits tend to be small relative to day-ahead and real-time prices. Ultimately, this reduces liquidity in the day-ahead market and explains why the gross profitability of virtual transactions is larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitrated). Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be more consistent with a “cost causation” principle, which would involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC.

### **B. Drivers of Day-Ahead NCPC Charges**

Day-ahead NCPC charges are incurred when a resource is scheduled in the day-ahead market, but the revenues it receives from selling energy are not sufficient for it to recoup its as-offered start-up, no-load, and incremental costs. In addition to clearing day-ahead bids and offers in the day-ahead market, ISO-NE also commits resources in the day-ahead market to satisfy all of its forecasted reliability needs for the following day. Thus, most NCPC charges for local reliability commitments are incurred in the day-ahead market rather than the real-time market (as is the case for most other RTOs).

Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because commitments that are made to satisfy a reliability requirement affect which resources should be committed economically in the day-ahead market. For example, if a 400 MW generator must be committed for reliability in a particular load pocket, the generator also helps satisfy demand throughout the system so it will likely reduce the amount of resources that are economic to commit outside the load pocket.

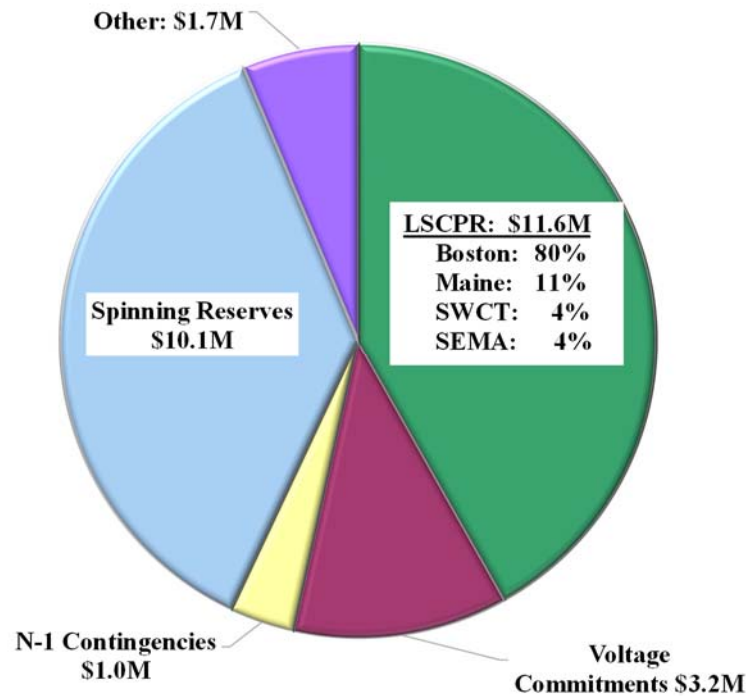
To summarize the causes of day-ahead NCPC, Figure 10 shows NCPC charges in 2017 incurred for the following reasons: local second contingency protection, voltage support, local single contingency protection, system-level reserve requirement, and other.<sup>51</sup> The figure also provides regional subtotals for local second contingency protection. The largest contributor to NCPC charges in the day-ahead market is commitments to satisfy local second contingency requirements, primarily in Boston. The next largest contributor is commitments to satisfy system-level ten-minute spinning reserve requirements. The market effects of these commitments are analyzed later in this section – local second contingency commitments are

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<sup>51</sup> *Local second contingency protection resources* are committed to maintain sufficient reserves to protect an area in case the two largest contingencies were to occur in a 30-minute period. *Voltage support resources* are committed to maintain local voltage or resolve a reactive power requirement. *Local first contingency protection resources* are committed to maintain transmission security in case a contingency was to occur unexpectedly. *System-level reserve requirements* are defined for TMSR, TMNSR, and TMOR, and resources may be committed to satisfy those requirements in the day-ahead market.

evaluated in Subsection C, and commitments for system-level ten-minute spinning reserves are evaluated in Subsection D.

**Figure 10: Summary of Day-Ahead NCPC Charges by Category**  
2017



One notable factor that leads to inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges is that some combined-cycle generators are offered in a multi-turbine configuration even though they are able to operate the turbines individually. In many cases, the reliability requirement could be satisfied with the commitment of a single turbine configuration, so needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. Multi-turbine combined-cycle commitments accounted for 34 percent of the capacity committed for local reliability in the day-ahead market in 2017. We evaluate the market effects of these excess commitments in 2017 in Subsection C.

### C. Day-Ahead Commitment for Local Second Contingency Protection

The ISO commits resources for local second contingency protection needs in the day-ahead market. The purpose of these commitments is to ensure that ISO-NE can reposition the system in key areas to be able to respond to the second largest system contingency after the largest contingency has occurred.

While these commitments may be justified from a reliability perspective, they can lead to inefficient prices in the local area for two reasons.

- First, the units receiving NCPC payments systematically receive more revenue than the market revenues and cause lower-cost resources to set energy prices.
- Second, the costs of these resources will not be reflected in the prices of the operating reserves that are also satisfying the underlying reliability requirement.

These two issues distort economic incentives in favor of high-cost units with less flexible characteristics because, all else equal, they receive higher revenue than lower-cost more flexible units. Hence, when local NCPC is substantial, it is important to identify the underlying causes and consider market reforms as needed to improve the efficiency of prices for energy and operating reserves in local areas.

These concerns are sometimes exacerbated by two other issues that can lead to excess commitment for local second contingency protection.

- First, the day-ahead commitment software does not model the full set of energy and operating reserve requirements, particularly when the commitment of a large unit will alter one of the contingencies for which the software is scheduling. The ISO represents these factors indirectly in the day-ahead commitment logic, but this does not minimize costs because the procurement of operating reserves is not co-optimized with energy.
- Second, some generators that are committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient.

Of capacity that was committed by the day-ahead market model for local second contingency protection in Boston in 2017, we estimate that 77 percent of the capacity would not have been needed to satisfy the local second contingency requirements modeled in the day-ahead market if energy and operating reserves had been co-optimized with the requirement.<sup>52</sup>

The ISO could avoid excess commitment by: (a) implementing ancillary services markets that are co-optimized with energy in the day-ahead market, and (b) modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO to commit just one turbine at a multi-turbine group. Not only would these changes result in production cost savings and more efficient prices for energy and reserves as discussed above, but they would also improve market incentives for reliable performance, flexibility, and availability under a wide range of conditions—not just operating reserves shortages. Directing more revenue to generators that have these characteristics would shift investment accordingly and reduce reliance on the capacity market for attracting investment to local areas.

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<sup>52</sup> Note, this evaluation considered only local second contingency protection commitments in Boston that were made by the day-ahead market's commitment software, but it does not include commitments that were determined by operations before the day-ahead market. When interpreting these results, it is also important to consider that local second contingency protection units might still have been committed for another constraint even if they were not needed specifically to satisfy the minimum capacity requirement for the local area.

Finally, satisfying these local requirements through a day-ahead operating reserve market and commitment should substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These NCPC payments provide adverse fuel procurement incentives. Under the market power mitigation rules, a generator that is committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.<sup>53</sup> For example, one dual-fuel generator in Boston operated on fuel oil for 42 days in 2017 when natural gas was less expensive than fuel oil.<sup>54</sup> Enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

#### **D. Day-Ahead Commitment for System Level Operating Reserve Requirements**

As discussed in Subsection B, the day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to energy schedules. However, these reserve requirements are not enforced in the day-ahead market pricing software because ISO-NE does not have day-ahead reserve markets. Consequently, generators are frequently committed in the day-ahead market to satisfy operating reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements. We estimate that:

- Additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in approximately 4,900 hours in 2017.<sup>55</sup>
- Since the reserve requirement is not enforced in the pricing software, these commitments reduced energy prices across the system by an average of \$0.82/MWh across all hours.
- Pricing these operating reserve requirements in the day-ahead market would provide efficient compensation for resources providing ten-minute spinning reserves.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. This will become increasingly important as the penetration of intermittent renewable generation increases over the coming decade. Under-compensating generators that have flexible characteristics shifts investment incentives towards other types of resources and increases dependence on the capacity market for attracting the investment necessary to maintain reliability.

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<sup>53</sup> See Section III.A.5.5.6.2. of the ISO Tariff.

<sup>54</sup> See EPA Air Markets Program Data at <https://ampd.epa.gov/ampd/>.

<sup>55</sup> We found very few hours in 2017 when additional capacity was committed to satisfy the total 10-minute reserve and 30-minute reserve requirements. This is likely because New England has sufficient offline fast start capacity to satisfy these requirements in the vast majority of hours.



## E. Drivers of Real-Time NCPC Charges

Real-time NCPC charges are incurred when a resource is scheduled in the real-time market, but the revenues it receives are not sufficient for it to recover its as-offered commitment and dispatch costs.<sup>56</sup> Table 3 summarizes real-time NCPC charges in 2017 for the following categories based on their allocations:

- Local Reliability – Units that receive NCPC credits in this category are committed or dispatched to primarily satisfy the second contingency protection or the voltage requirements in the local area. This NCPC uplift is allocated to local loads.
- External Transactions – Transactions are scheduled based on their offer prices, but they receive NCPC credits if real-time prices are below their offer. This NCPC uplift is allocated to real-time deviations at the proxy bus (excluding CTS transactions).
- Market-Wide Charged to Real-Time Load Obligation (“RTLO”) – These are the economic NCPC uplifts that are charged to market-wide load based on their real-time load obligations, including:
  - Generator Performance Audit – Paid to generator for audits initiated by the ISO.
  - Dispatch Lost Opportunity Cost – Paid to a resource instructed by the ISO to run at a level less than its economic dispatch point. This NCPC credit was implemented on March 1, 2017.
  - Rapid-Response-Pricing Opportunity Cost – Paid to a resource that is postured down when a rapid-response resource is setting price, which compensates the resource for the difference between the amount it would have earned for energy and reserves absent being postured down. This NCPC credit was implemented on March 1, 2017.
  - Resource Posturing – Paid opportunity costs to resources that are held in reserve for reliability even when it would be more profitable to generate.
- Market-Wide Charged to Real-Time Deviation – These are the economic NCPC uplifts charged to market-wide real-time deviations, which include deviations from generation, load, external transaction, and virtual transactions.
  - Fast Start Resources – These are fast start resources that are committed primarily by the look-ahead model, but do not set price.
  - Supplemental Commitment after DAM – These are non-fast-start units that are committed after the day-ahead market for reliability.
  - Other – These include NCPC credits that resulted from actions by the ISO (e.g., cancel the start of a resource, instruct a resource for regulation) and ramping limitations of resources when following dispatch.

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<sup>56</sup> This includes opportunity costs if a generator would have earned more by not following the ISO’s instructions.



**Table 3: Summary of Real-Time NCPC Charges by Category**  
2017

Real-Time NCPC Category	Charges (Million \$)	Share of RT NCPC
<b>Local Reliability</b>		
Local Second Contingency	\$0.8	3%
Voltage Support	\$0.1	1%
SCR	\$0.01	0%
Multi-Turbine Portion	\$0.4	2%
<b>External Transactions</b>	\$1.9	8%
<b>Market-Wide Charged to RTLO</b>		
Generator Performance Audit	\$0.6	2%
Dispatch LOC	\$2.8	12%
Rapid Response OC	\$2.6	11%
Resource Posturing	\$1.6	7%
<b>Market-Wide Charged to RT Deviation</b>		
Fast Start Resources	\$9.0	37%
Supplemental Commitment after DAM	\$1.5	6%
Other	\$2.8	12%
<b>Total</b>	\$24.1	

Local reliability requirements and other supplemental commitments after the day-ahead market accounted for a relatively small share (collectively 12 percent) of real-time NCPC in 2017. This was down from prior years because of reduced need to commit generation for local Boston-area reliability following transmission upgrades.

Fast start resources accounted for the largest share of real-time NCPC in 2017. These resources were committed primarily by the look-ahead market model (i.e., the Generation Control Application) based on forecast system needs. However, forecast errors frequently led these resources to be uneconomic under actual real-time prices, resulting in sizable NCPC charges.

Although the real-time NCPC from resource posturing was relatively small (7 percent) in 2017, we saw substantially higher levels in January 2018 during the cold snap because of fuel limitations. This raises concerns because the posturing NCPC gives certain resources perverse incentives by allowing them to earn more profit by running short of fuel and receiving NCPC for not generating than they could from generating and consuming their limited fuel. This is because they receive NCPC equal to the difference between the LMP and their offer for the duration of the posturing. Thus, if a generator has only three hours of fuel left and it is postured by the ISO for 12 hours, it will be paid for 12 hours of opportunity costs, which is far more than the profit it would make from generating for three hours.

It is important to allocate NCPC charges in an efficient manner. However, most of the NCPC charges that are allocated to real-time deviations are not caused by real-time deviations.

Specifically, we find that the supplemental commitment for market-wide reliability after the day-ahead market is the only category that is driven partly by real-time deviations and this accounted for just 11 percent of real-time NCPC charges in 2017 that were allocated to real-time deviations. This is similar to our finding in 2016. These commitments are sometimes caused by under-scheduling of energy in the day-ahead market or the loss of a significant supply resource after the day-ahead market. So, real-time deviations that reduce scheduling of physical resources in the day-ahead contribute to this category of NCPC charges, which includes virtual supply, under-scheduled load, or a generator that experiences a forced outage after the day-ahead market.

This misallocation of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help reduce NCPC charges such as virtual load and over-scheduling of load in the day-ahead market. Over-allocating NCPC charges to real-time deviations has provided strong disincentives for participation by virtual traders in the ISO-NE market as discussed earlier in this section. Hence, costs should only be allocated to real-time deviations to the extent that they cause the costs and the balance should be allocated to load.

### **F. Conclusions and Recommendations**

In our assessment of day-ahead NCPC charges, we found that 42 percent was attributable to commitments for local second contingency protection, while 37 percent was attributable to commitments for the system-level 10-minute spinning reserve requirement. Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. The absence of a co-optimized day-ahead operating reserve market resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 77 percent of which would not have been needed under a co-optimized energy and reserve market.
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate there were 4,900 hours when additional generation was committed to satisfy the system level 10-minute spinning reserve requirement, which was not reflected in prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

We make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves in the day-ahead market.

- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

One advantage to co-optimizing the scheduling of energy and operating reserves in the day-ahead market is that it would facilitate the elimination of the forward reserve market. As in prior years, nearly all of the resources assigned to satisfy forward reserve obligations in 2017 were fast-start resources capable of providing offline reserves. The value of the forward reserve market is questionable because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day.

The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs.

In assessing the real-time NCPC charges, we found that just 6 percent of the real-time NCPC can be attributed to real-time deviations, although 55 percent of all real-time NCPC are allocated to these deviations. Hence, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. We recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a “cost causation” principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.



## VI. ASSESSMENT OF COORDINATED TRANSACTION SCHEDULING

Coordinated Transaction Scheduling (“CTS”) was implemented with the NYISO on December 15, 2015. In this process, the NYISO and ISO-NE exchange real-time market information to schedule external transactions more efficiently.<sup>57</sup> The CTS intra-hour scheduling system is very important because it is a means to allow the RTOs to fully utilize the large interface between the markets. If it functions well, this lowers costs and improves reliability in both areas. The CTS has at least three advantages over the hourly price-based scheduling system that was used previously.

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

It is important to evaluate the performance of CTS on an on-going basis to maximize its benefits and identify potential improvements. The CTS performance depends critically on two factors: the RTOs’ forecasts used clear the CTS bids that result in interchange adjustments, and the quantity and price-sensitivity of the CTS bids themselves.

In the subsections below, we first provide a summary evaluation of the efficiency of the CTS process in 2017, then evaluate these two key factors. We also evaluate the CTS performance relative to “Tie Optimization”, a process whereby the RTOs would make interchange adjustments based exclusively on the price forecasts without participant bids.

### A. Evaluation of Scheduling Efficiency of CTS Process

The first analysis evaluates the overall efficiency of the CTS scheduling process (relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process). To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we compare the final CTS schedule to advisory schedules in NYISO’s RTC

<sup>57</sup> ISO-NE provides a forecasted supply curve to NYISO every 15 minutes, which the NYISO uses to schedule CTS transactions. The NYISO’s scheduling model (“RTC”) evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the CTS bid and (b) ISO-NE’s forecasted marginal price. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to the sum of: (a) the bid and (b) ISO-NE’s forecasted marginal price.

model that are determined 30 minutes before each hour.<sup>58</sup> This method likely under-estimates the benefits of CTS because it uses advisory schedules that are informed by the ISO-NE forecast.

Table 1 shows the market efficiency gains (and losses) from CTS in 2016 and 2017, which is measured by production cost savings. Production cost savings are the reduction in the as-offered dispatch costs of the generators dispatched to satisfy the system's needs. Importantly, lowering producing costs will tend to lower prices and produce consumer savings that are much larger than the production cost savings. Nonetheless, we report producing costs savings because they are the most accurate measure of efficiency gains. The table shows the following breakdowns of the savings:

- **Projected Savings at Scheduling Time** – This measures the expected production cost savings at the time when RTC determines the interchange schedule across the interface.
- **Net Over-Projected Savings** – This estimates the portion of savings that were inaccurately projected because of NYISO and ISO-NE forecast errors.
- **Unrealized Savings** – This estimates production cost savings not realized because of:
  - **Real-time Curtailment** - Some of RTC scheduled transactions may be curtailed for various reasons (e.g., real-time cuts for reliability). The reduction of flows in the efficient direction reduces market efficiency gains.
  - **Interface Ramping** – The price forecasting engine and real-time dispatch model in each market (e.g., CTSPE and UDS in ISO-NE) assume different timing for interface schedules to ramp in, which leads a portion of projected savings to be unrealized.
  - **Price Curve Approximation** – CTSPE forecasts a 7-point piecewise-linear supply curve and transforms it into a step-function for use in CTS. This causes the CTS scheduling to not be fully consistent with ISO-NE's marginal cost of interchange.

The results are shown separately for periods with large price forecast errors (>\$20/MWh) and smaller forecast errors. The table also shows the size and frequency of the adjustments:

- **% of All Intervals** – This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
- **Average Flow Adjustment** – The estimated CTS adjustment where positive values for the net indicate adjustments from New England to New York.

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<sup>58</sup> RTC is the NYISO's real-time commitment engine used to schedule CTS transactions and other external transactions. RTC determines hourly schedules at 15 minutes past previous hour, while determining advisory schedules for future periods. Our evaluation uses these advisory schedules to estimate the hourly schedules that would have occurred without CTS by taking the average of the four advisory quarter-hour schedules that RTC produced for each hour.

**Table 4: Efficiency of Intra-Hour Scheduling Under CTS**  
2016 - 2017

		Average/Total During Intervals w/ Adjustment						
		2017			2016			
		Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total	Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total	
% of All Intervals w/ Adjustment		77%	12%	89%	75%	11%	87%	
Average Flow Adjustment (MW)	Net Imports	14	0	12	-0.3	-2	-0.5	
	Gross	95	109	97	73	101	76	
Production Cost Savings (\$ Million)	Projected at Scheduling Time	\$3.7	\$2.2	\$5.9	\$2.4	\$2.1	\$4.5	
	Net Over-Projection by:	NY	-\$0.1	-\$0.1	-\$0.2	-\$0.02	-\$0.3	-\$0.3
		NE	\$0.1	-\$0.5	-\$0.5	-\$0.1	-\$1.0	-\$1.1
	Other Unrealized Savings	-\$0.2	-\$0.3	-\$0.4	-\$0.4	-\$0.7	-\$1.1	
	Actual Savings	\$3.5	\$1.4	\$4.8	\$1.9	\$0.1	\$2.0	

Our analyses show that the estimated production cost savings increased from \$2.0 million in 2016 to \$4.8 million in 2017, indicating that the overall performance of the CTS process improved notably from 2016 to 2017. The higher savings achieved in 2017 resulted from:

- Increased flow adjustments – Gross flow adjustments (including both import and export directions) averaged nearly 100 MW in 2017, up 28 percent from 2016. This was partly due to increased price-sensitive CTS bidding in 2017 (see Figure 11); and
- Better price forecasting – During intervals with CTS adjustments, NYISO forecast errors fell from 29 percent in 2016 to 25 percent in 2017, and ISO-NE forecast errors fell from 33 percent in 2016 to 24 percent in 2017. As a result, the net over-projected savings from forecast errors fell from \$1.4 million in 2016 to \$0.7 million in 2017.

The table shows that most of the unrealized production cost savings were caused by price forecast errors. The reduction in savings was much larger in periods when the forecast errors exceeded \$20 per MWh and much smaller in other periods. Therefore, improvements in the CTS process should focus on identifying sources of forecast errors (which are discussed later in this subsection).

Finally, our evaluation likely under-estimates both projected and actual savings because our methodology for identifying the hourly level of interchange that would have occurred (absent CTS) will still be influenced by the lookahead forecast of ISO-NE. Nonetheless, these results remain useful for identifying sources of inefficiency in the CTS process.

## B. Evaluation of CTS Bidding Patterns

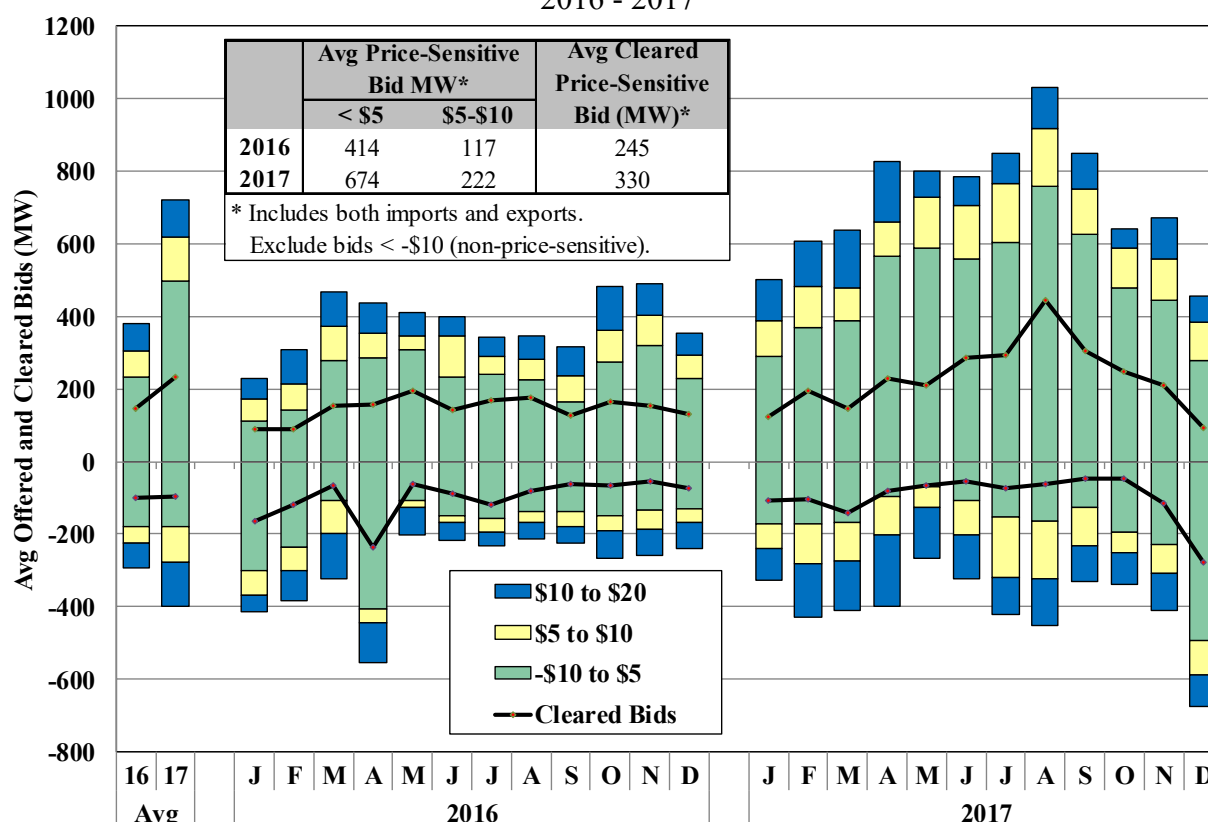
CTS requires traders to submit bids that will be scheduled only when the RTOs' forecasted price spread is greater than the bid price. Hence, the performance of the CTS depends critically on the submission of a substantial quantity of price-sensitive bids by market participants, which we evaluate in this subsection.

Figure 11 evaluates the price-sensitivity of CTS bids, showing the monthly and annual average quantities of bids during peak hours (i.e., HB 7 to 22) in 2016 and 2017. Positive numbers indicate export bids from New England to New York and negative numbers represent import offers from New York to New England.

The bars show the average quantities of price-sensitive CTS bids for three price ranges. The two black lines in the chart indicate the average scheduled price-sensitive CTS imports and exports in each month. The inset table summarizes the quantity of price-sensitive bids in each year along with the average quantity of cleared transactions.

The average amount of price-sensitive CTS bids submitted at the NE/NY interface rose notably from 2016 to 2017. In 2017, the amount of bids offered between \$-10 and \$10 per MWh averaged nearly 900 MW (including both import offers and export bids), up nearly 70 percent from 2016. Likewise, the cleared bids in the same price range increased 35 percent from 2016 to 2017. As a result, interchange schedules were adjusted more frequently in 2017 and higher savings in production costs were achieved as a result (as shown in Table 4).

**Figure 11: Average CTS Transaction Bids and Offers by Month**  
2016 - 2017



Despite the increase in price-sensitive scheduling, the volume of price-sensitive CTS bids was still modest compared to the transfer capability of the interface. This is largely attributable to risks that participants face – a significant portion of scheduled CTS transactions may be



unprofitable because of forecast errors in the scheduling process. Thus, if the ISOs can improve the price forecasts that underlie the CTS prices, it should further improve both the quantity and the price-sensitivity of the CTS bids, and ultimately allow the process to achieve larger savings.

### C. Performance of Price Forecasting and Drivers of Forecast Errors

Price forecasting by the RTOs is essential in the CTS process because it determines how efficiently the CTS process will clear CTS bids and make associated interchange adjustments. It also is the key determinant of risk for the participants submitting CTS bids (i.e., that the ISO will strike CTS bids that ultimately result in settlement losses because of the forecast errors). Hence, accurate forecasting will tend to reduce participants bid prices and allow transactions to clear be scheduled based on smaller forecasted price spreads between the markets. In this subsection, we evaluate the RTO's forecasting performance and identify the key sources of forecast errors to facilitate improvements.

#### 1. Price Forecasting Performance

The next analysis compares the performance of price forecasting by the two ISOs in the CTS process. Figure 12 shows the cumulative distribution of forecast errors in 2017. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price. The figure shows the ISO-NE forecast error based on the piecewise linear curve produced by its forecasting model and based on the step-function that the NYISO model uses to approximate the piecewise linear curve.<sup>59</sup>

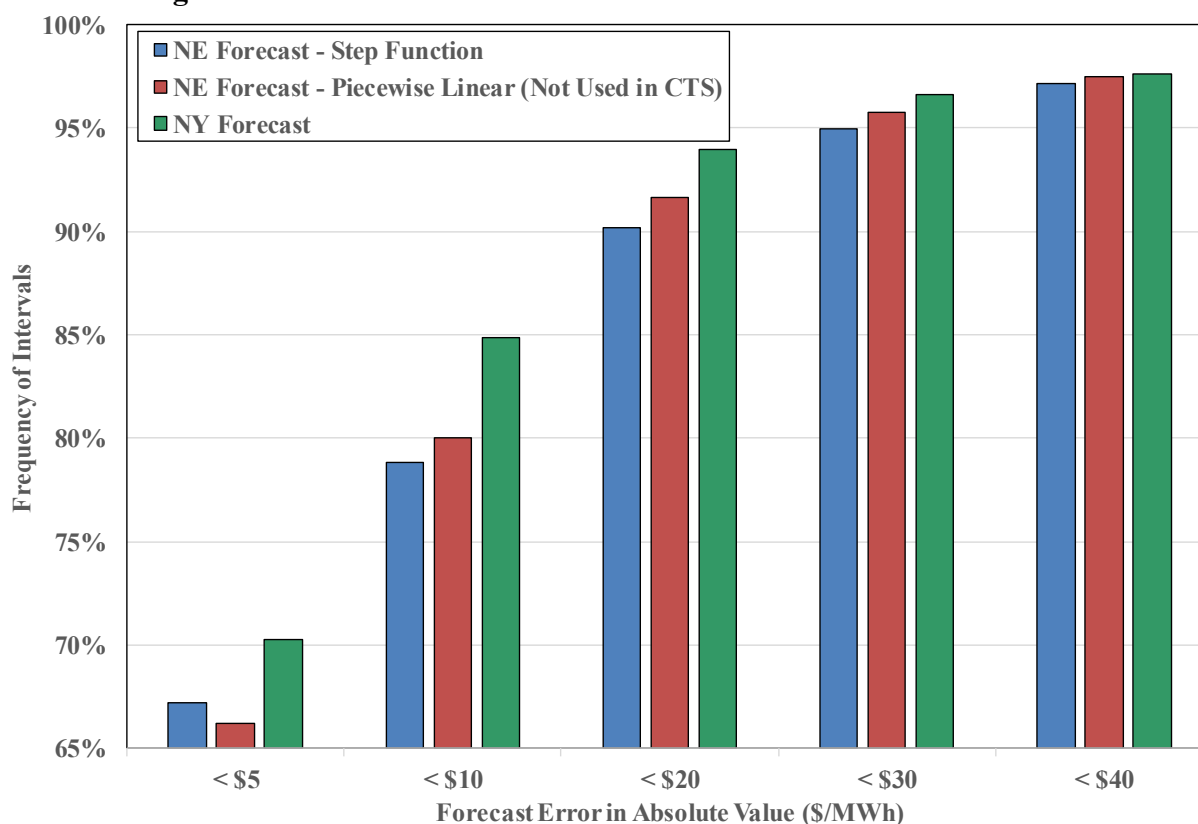
Figure 12 shows that the forecasting performance was slightly better on the NYISO side of the interface in 2017. For example, price forecast errors were greater than \$10/MWh in roughly 20 percent of intervals at the ISO-NE side but in only 15 percent of the intervals at the NYISO side. This is expected because the CTS process requires ISO-NE to produce a forecast first, and this is used as an input to the NYISO forecast. Nonetheless, there is ample opportunity for improvement by both RTOs and we are identifying the sources of the forecast errors and recommended improvements for both RTOs.

The improvements recommended to NYISO are contained in the NYISO 2017 State of the Market Report.<sup>60</sup> The next subsection summarizes our analysis of factors that contribute to forecast errors by ISO-NE.

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<sup>59</sup> Figure 15 in the Appendix shows an example of piecewise linear curve and its approximated step-function curve.

<sup>60</sup> See Section XI.B in our *2017 State of the Market report for the New York ISO*.

**Figure 12: Distribution of Price Forecast Errors Under CTS in 2017**

## 2. Drivers of Price Forecasting Errors

The CTS Pricing Engine (“CTSPE”) is a forecasting tool that ISO-NE uses to provide supply curves for the CTS scheduling process. The effective supply curves are normally generated with a lead time of around 40 minutes.<sup>61</sup> Inconsistency between CTSPE and UDS prices (as shown in Figure 12) is an indication that some look-ahead assumptions may be inaccurate.

We have performed a systematic evaluation of factors that led to inconsistencies between CTSPE prices and UDS prices in 2017. This evaluation measures the contributions of individual factors and inputs in each pricing interval to differences between CTSPE and UDS, and this allows us to compare the relative significance of factors that contribute to forecast errors over time.<sup>62</sup> We summarize the factors and inputs that lead to differences between CTSPE and UDS in the following categories:

- Load Forecast Error – Combines the forecast of the load forecasting model with any upward or downward adjustment by the operator.
- Wind Forecast Error – Primarily the error of the wind forecasting model.

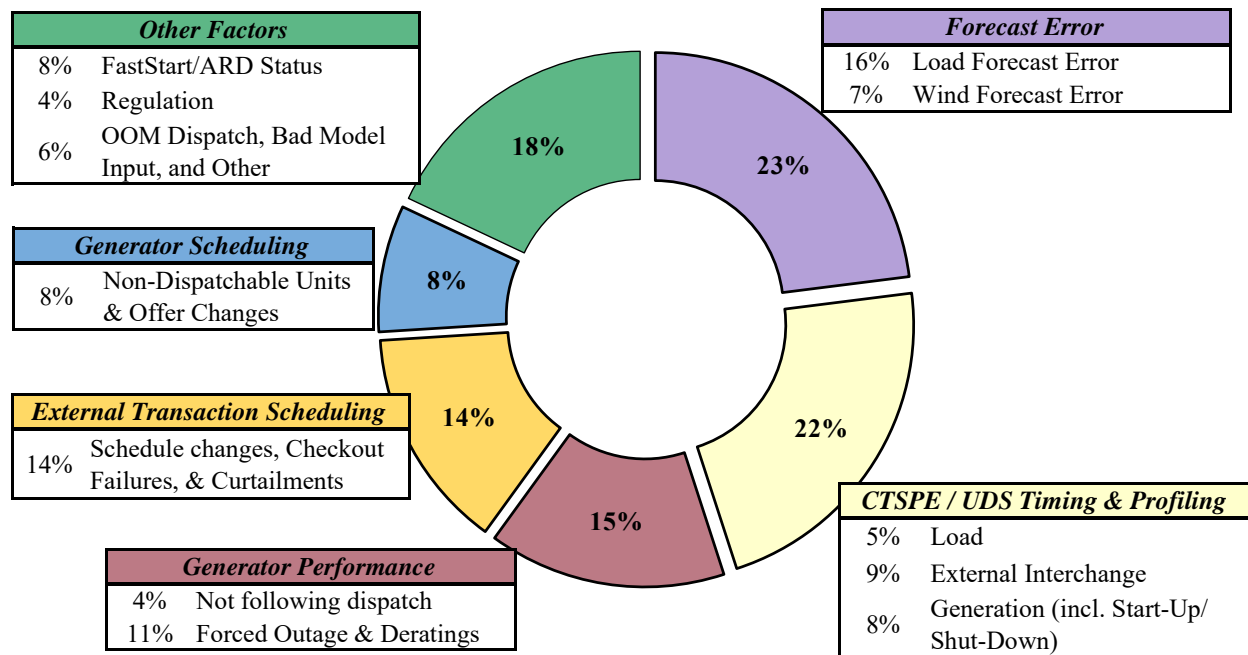
<sup>61</sup> CTSPE is a 12-interval look-ahead model. The first interval is 7 minutes ahead and the remaining 11 intervals each look out an additional 15 minutes. The third interval is sent to NYISO for CTS scheduling.

<sup>62</sup> See the Appendix Section VII.A for a detailed description of this metric (illustrated with examples).

- Schedule Timing and Ramp Profiling – This includes differences that result from inconsistent timing and treatment of ramp between CTSPE and UDS for load forecast, external interchange, self-scheduled generation, and dispatchable generation.
- Generator Not Following Dispatch – Includes situations where a generator’s UDS schedule is affected by a ramp-constraint and where the ramp-constraint was tighter as a result of the generator not following its schedule in a previous interval.
- Generator Forced Outages and Derates
- External Transaction Schedule Changes, Curtailments and Checkout Failures
- Generator on OOM Dispatch
- Generator Dispatch In Merit – Includes differences that result from economic dispatch of fast-start units, ARD resources, and non-fast-start units by CTSPE and UDS.

The evaluation distinguishes detrimental changes between CTSPE and UDS (i.e., that cause prices to diverge between CTSPE and UDS) versus beneficial changes (i.e., that improve price convergence). Figure 13 summarizes the price divergence metric for “detrimental” factors.

**Figure 13: Detrimental Factors Causing Divergence Between CTSPE and UDS**  
March to December 2017<sup>63</sup>



Our evaluation identified two groups of factors that contributed the most to divergence between CTSPE and UDS in 2017. First, differences in load forecasting and wind forecasting were the most significant contributor, accounting for 23 percent of the overall divergence between CTSPE and UDS in 2017. Errors in load forecasting had a larger impact partly because of the difficulty

<sup>63</sup> January and February 2017 were excluded from the analysis to focus on the period after the ISO implemented major changes to the UDS pricing logic on March 1, 2017.

to forecast behind-the-meter (“BTM”) net demand levels as the BTM solar generation tends to vary unpredictably with rapid changes in weather patterns.

The second largest category, which accounted for 22 percent of the divergence, was related to inconsistencies in assumptions related to the timing of the CTSPE evaluation versus the UDS evaluation. This includes inconsistencies in the ramp profiles assumed for external interchange, load, self-scheduled generators, and dispatchable generators starting-up and shutting-down.

For example, CTSPE assumes external transactions ramp to their schedule by the quarter-hour (i.e., at :00, :15, :30, and :45), while UDS assumes that external transactions start to ramp five minutes before the interval and reach their schedule five minutes after the interval (five minutes later than CTSPE). Since a single UDS solution may be used for several 5-minute intervals in a row, if UDS runs with a target time of :10 and it is not replaced by a newer run at :15, CTSPE will use the external interchange schedule for :15, while UDS will use the schedule for the previous 15-minute period. These inconsistencies were a significant source of divergence between the two models.<sup>64</sup>

Many other factors collectively made significant contributions to CTSPE forecast errors in 2017. These inconsistencies warrant further evaluation to estimate the forecasting improvements that would be achieved by reducing the inconsistencies. This will allow the ISO to prioritize the necessary enhancements to address inconsistencies between CTSPE and UDS. Since the analyses discussed in Subsection A indicate that the most significant production cost inefficiencies came from periods when the forecast error exceeded \$20 per MWh, we plan to further analyze contributors to forecast error during such periods.

### **D. Expected Performance of the Tie Optimization Alternative**

When ISO-NE and NYISO considered market design changes to improve interchange scheduling between the two markets, two options emerged: CTS and Tie Optimization. Unlike CTS, Tie Optimization would adjust interchange based only on the ISO’s forecasts without trader participation. Although CTS was adopted, the ISOs’ joint proposal included a process (and trigger) for switching to Tie Optimization if warranted.<sup>65</sup> This subsection evaluates whether Tie Optimization would likely have performed better than CTS at the primary NE/NY interface during the second year of implementation.

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<sup>64</sup> Figure 16 in the Appendix illustrates differences that result from the ramp profiles that are assumed by CTSPE and UDS and other timing issues.

<sup>65</sup> The trigger requires that, for the second year of CTS implementation, : (i) the “foregone” bid production cost savings from implementing CTS rather than Tie Optimization is greater than \$3 million; and (ii) the “foregone” savings from (i) is more than 60 percent of the “foregone” savings of implementing Tie Optimization rather than Optimal Interchange.

As required by the Tariff, we performed a study to estimate the savings that would result from the Tie Optimization alternative. Specifically, this analysis compared two scenarios:<sup>66</sup>

- A Tie Optimization scenario – Interchange that would have occurred if the ISOs had an infinite number of zero bids given the ISOs’ actual price forecasts; and
- An Optimal Interchange scenario – Interchange that would have occurred if the ISOs had an infinite number of zero bids assuming perfect price forecasts;

Table 5 shows the estimated production cost savings in 2017 for the Optimal Interchange (“OI”) and Tie Optimization (“TO”) cases for intervals where the cases would make the same adjustment, or when the TO case would deviate from the OI case in the following ways:

- Over-Adjustment: (a) TO over-adjusts the interchange in the same direction as OI, or (b) TO adjusts but OI does not.
- Under-Adjustment: (a) TO under-adjusts the interchange in the same direction as OI, or (b) OI adjusts but TO does not.
- Adjustment in Wrong Direction: TO adjusts in the opposite direction as OI.

**Table 5: Estimated Production Cost Savings for TO and OI**  
By Category of Interchange Adjustment, 2017

Category of Adjustment		Production Cost Savings		
		Tie Optimization (TO)	Optimal Interchange (OI)	% of 5-Minute Intervals
No Adjustment				22%
Same Adjustment		\$0.6	\$0.6	5%
Over Adjustment	Same Direction as OI	-\$0.03	\$0.1	9%
	No OI Adjustment	-\$0.5		9%
Under Adjustment	Same Direction as OI	\$0.7	\$1.5	17%
	NO TO Adjustment		\$2.0	24%
Adjustment in Wrong Direction		-\$1.3	\$1.1	14%
<b>Total</b>		<b>-\$0.4</b>	<b>\$5.3</b>	<b>100%</b>

We estimate that, in 2017, Tie Optimization would have *increased* regional production costs by \$0.4 million (relative to the current CTS process), while Optimal Interchange would *reduce* these costs by \$5.3 million. These results are very similar to the findings in our assessment for 2016.

Forecast errors are the primary reason that Tie Optimization would have raised costs. The table shows that Tie Optimization would result in the same interchange adjustments and benefits as

<sup>66</sup> Assumptions and methods used in our analysis can be found in the presentation *Second Year Evaluation of CTS between New England and New York* to NEPOOL Markets Committee Meeting on May 8, 2018

Optimal Interchange in only 27 percent of the intervals in 2017. In the remaining 73 percent of intervals, Tie Optimization would lead to reduced or *negative* savings from sub-optimal adjustments because of the forecast errors discussed in the prior subsection.

### E. Conclusions and Recommendations

Based on a detailed study of the performance of CTS scheduling process between New York and New England, we find that the performance of the CTS process improved substantially in 2017 because of improvements in price forecasts and increased CTS bid liquidity. However, forecast errors are still significant enough that moving from CTS to Tie Optimization would increase *costs* rather than savings.

We have performed a systematic evaluation to identify factors that contributed to forecasting errors in CTSPE and find that:

- Errors in load forecasting and wind forecasting were the largest contributor in 2017, accounting for 23 percent of overall divergence between CTSPE and UDS.
- Differences in timing and ramp profiles between CTS and UDS were the second largest contributor, accounting for 22 percent of the overall divergence.
- Forced outages and poor dispatch performance by generators accounted for 15 percent of the divergence.
- Other external interfaces had schedule changes, transaction checkout failures, curtailments and other changes that accounted for 14 percent of the divergence.
- Other factors also made significant contributions collectively, but had relatively small impact individually.

Although there are significant opportunities to improve the performance of the CTS process, it is important to note that the CTS process with NYISO is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). The primary reason the other CTS processes have performed poorly is that the CTS are allocated substantially costs and transmission charges. We applaud ISO-NE and NYISO for agreeing not the charge such charges to their CTS transactions.

We will continue monitor the performance of CTS and evaluate factors that contribute to particularly large forecast errors (>\$20 per MWh) because these account for a large share of the production cost inefficiencies identified in our analyses.

## VII. APPENDIX: ASSUMPTIONS USED FOR KEY ANALYSES

### A. Divergence between CTSPE and UDS

Figure 13 provide the results of our systematic evaluation of factors that lead to inconsistent results between CTSPE and UDS. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it distinguishes between factors that *cause* differences between CTSPE forecast prices and actual RT prices (which we call “detrimental” factors) and factors that *reduce* differences between CTSPE forecast prices and actual RT prices (which we call “beneficial” factors).<sup>67</sup>

Inconsistencies between CTSPE and UDS prices are an indicator of forecast errors that may have led to inefficient CTS scheduling outcomes. For example, suppose that CTSPE forecasts an LMP of \$45/MWh with 1000 MW of CTS imports from NYISO but UDS clears at \$65/MWh with the same level of imports because actual load is 100 MW higher than the load forecast that was used in CTSPE. Suppose that UDS satisfies the additional load with 100 MW of online generation priced at \$65/MWh, while 100 MW of CTS import offers priced at \$50/MWh were not scheduled because of the under-forecast by CTSPE. In this example, the under-forecast of load leads the ISO to use 100 MW of \$65/MWh generation rather than \$50/MWh of CTS imports, resulting in \$1,500/hour (= 100 MW \* {\$65/MWh - \$50/MWh}) of additional production costs. Thus, the inefficiency resulting from poor forecasting by CTSPE is correlated with:

- The inconsistency between the price forecasted by CTSPE versus the actual price determined by UDS; and
- The inconsistency between the MW value used in CTSPE versus the one used in UDS.

Hence, we use a metric that multiplies the MW-differential between CTSPE and UDS with the corresponding price-differential for resources that are explicitly considered and priced by the real-time market models.

#### 1. Description of Evaluation Metric

In particular, for generation resource, external transaction, or load  $i$ , our inconsistency metric is calculated as follows:

$$\text{Metric}_i = (\text{NetInjectionMW}_{i,\text{CTSPE}} - \text{NetInjectionMW}_{i,\text{UDS}}) * (\text{Price}_{i,\text{CTSPE}} - \text{Price}_{i,\text{UDS}})^{68}$$

<sup>67</sup> Although CTSPE produces twelve forecasts looking 210 minutes (i.e., ten 15-minute intervals plus two 30-minute intervals) into the future, this metric is calculated comparing just the third 15-minute interval of each CTSPE (which sets the supply curve for the CTS interface with NYISO) to the 5-minute real-time market interval (scheduling and pricing results from one UDS run can be associated with multiple 5-minute intervals).

<sup>68</sup> Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

Hence, for the load forecast in the example above, the metric is:

$$\text{Metric}_{\text{load}} = 100 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = -\$2,000/\text{hour}$$

For the high-cost generator in the example above, the metric is:

$$\text{Metric}_{\text{generator}} = -100 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = +\$2,000/\text{hour}$$

For the foregone CTS imports in the example above, the metric is:

$$\text{Metric}_{\text{import}} = 0 \text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = \$0/\text{hour}$$

The metric produces a negative value for the load forecast, indicating that the under-forecast of load was a “detrimental” factor that contributed to the divergence between the CTSPE forecast price and the actual UDS price. The metric produces a positive value for the generator that responded to the need for additional supply in UDS, indicating that the generator’s response was a “beneficial” factor that helped limit the divergence between the CTSPE forecast price and the actual UDS price. The metric produces a zero value for the foregone CTS imports, recognizing that the divergence was not caused by the CTS imports not being scheduled, but rather that their not being scheduled was the result of poor forecasting.

For transmission constraints that are modeled, it is also important to quantify inconsistencies that lead to divergence between CTSPE and UDS. To the extent that such inconsistencies result from reductions in available transfer capability that increase congestion, the metric will produce a negative (i.e., detrimental) result. On the other hand, if inconsistencies result from an increase in transfer capability that helps ameliorate an increase in congestion, the metric will produce a positive (i.e., beneficial) result. For each limiting facility/contingency pair  $c$ , the calculation utilizes the shift factors and schedules for resources and other inputs  $i$ :

$$\begin{aligned} \text{Metric\_BindingTx}_c = & \text{ShadowPrice}_{c,\text{CTSPE}} * \sum_i \{ \text{ShiftFactor}_{i,c,\text{CTSPE}} * (\text{MW}_{i,\text{CTSPE}} - \text{MW}_{i,\text{UDS}}) \} \\ & - \text{ShadowPrice}_{c,\text{UDS}} * \sum_i \{ \text{ShiftFactor}_{i,c,\text{UDS}} * (\text{MW}_{i,\text{CTSPE}} - \text{MW}_{i,\text{UDS}}) \} \end{aligned}$$

*Example 1*

The following two-node example illustrates how the metrics would be calculated if a generator tripped after the CTSPE run, causing a divergence between CTSPE and UDS prices. Suppose, CTSPE forecasts:

- Load<sub>A</sub> = 100 MW and Load<sub>B</sub> = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);



- Gen<sub>A</sub> produces 200 MW at a cost of \$20/MWh and Gen<sub>B</sub> produces 100 MW at a cost of \$20/MWh; and
- Thus, in CTSPE, Price<sub>A</sub> = \$20/MWh, Price<sub>B</sub> = \$20/MWh, Flow<sub>AB1</sub> on Line 1 = 33.33 MW, so the ShadowPrice<sub>AB1</sub> = \$0/MWh.

Suppose that before UDS runs, Gen<sub>B</sub> trips, increasing flows from Node A to Node B from 100 MW to 150 MW, requiring 50 MW of additional production from Gen<sub>A</sub> and requiring 50 MW of production from a \$45/MWh generator at Node B. This will lead to the following changes:

- Gen<sub>A</sub> produces 250 MW at a cost of \$20/MWh and Gen<sub>B2</sub> produces 50 MW at a cost of \$45/MWh; and
- Thus, in UDS, Price<sub>A</sub> = \$20/MWh, Price<sub>B</sub> = \$45/MWh, Flow<sub>AB1</sub> on Line 1 = 50 MW, so the ShadowPrice<sub>AB1</sub> = \$75/MWh.

In this example, the metric would be calculated as follows for each input:

- Metric\_Load<sub>A</sub> = \$0 = (-100MW - -100MW) \* (\$20/MWh - \$20/MWh)
- Metric\_Load<sub>B</sub> = \$0 = (-200MW - -200MW) \* (\$20/MWh - \$45/MWh)
- Metric\_Gen<sub>A</sub> = \$0 = (200MW - 250MW) \* (\$20/MWh - \$20/MWh)
- Metric\_Gen<sub>B</sub> = -\$2,500/hour = (100MW - 0MW) \* (\$20/MWh - \$45/MWh)
- Metric\_Gen<sub>B2</sub> = \$1,250/hour = (0MW - 50MW) \* (\$20/MWh - \$45/MWh)
- Metric\_BindingTx = \$1,250/hour = \$0/MWh \* 0.333 \* (200MW - 250MW) - \$75/MWh \* 0.333 \* (200MW - 250MW)

Metric\_BindingTx exhibits a positive value, indicating a beneficial factor because excess transfer capability was utilized to reduce the divergence between CTSPE prices and UDS prices that was caused by the generator trip at Node B. Metric\_GenB2 exhibits a positive value, indicating a beneficial factor because the divergence between CTSPE prices and UDS prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between CTSPE and UDS prices.<sup>69</sup>

## 2. Categories of Major Factors Affecting CTSPE/UDS Price Divergence

CTSPE and UDS forecasts are based on numerous inputs. We summarize inputs that change between CTSPE and UDS in the following major categories for the purposes of this analysis:<sup>70</sup>

<sup>69</sup> By design, as illustrated in this example, the sum of this metric over all beneficial and detrimental resources (including transmission lines) is zero when ignoring transmission losses.

<sup>70</sup> Note, that the metric for binding transmission constraints was still under development at the time of publication, and so the results in this report do not include this component. However, the overall significance of changes in transfer capability as a detrimental factor is likely to be small given the relatively low levels of congestion in New England. Nonetheless, we will incorporate this component in future reports.

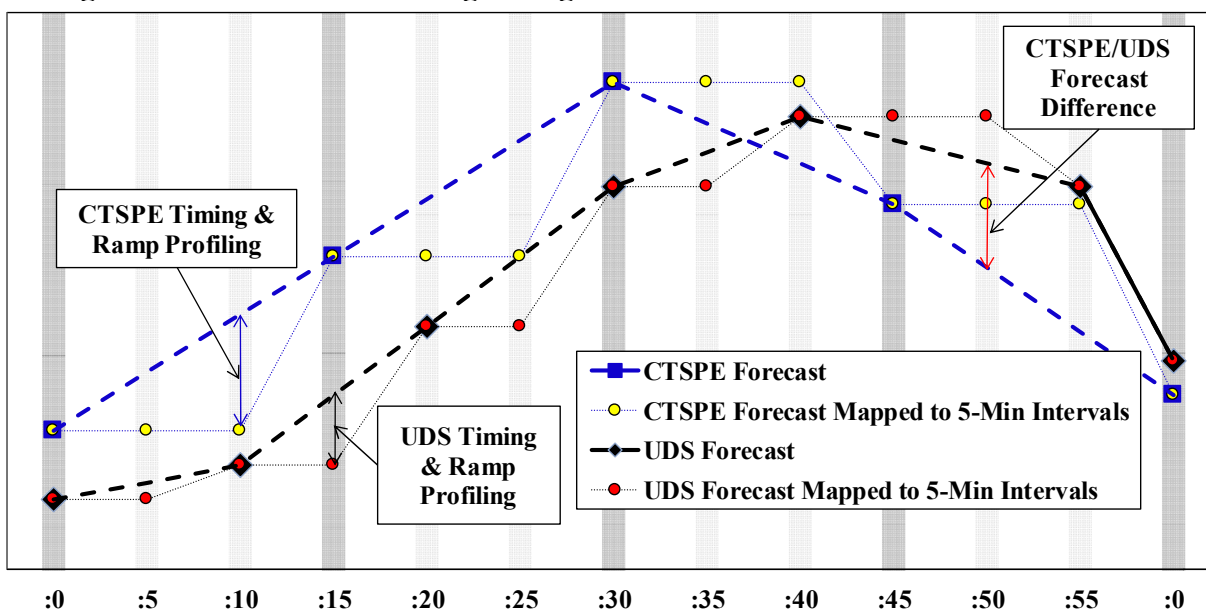
- Load Forecast Error – Combines the forecast of the load forecasting model with any upward or downward load bias adjustment by the operator.
- Wind Forecast Error – Primarily the error of the wind forecasting model.
- Schedule Timing and Ramp Profiling – This includes differences that result from inconsistent timing and treatment of ramp between CTSPE and UDS for load forecast, external interchange, self-scheduled generation, and dispatchable generation.
- Generator Not Following Dispatch – Includes situations where a generator’s UDS schedule is affected by a ramp-constraint and where the ramp-constraint was tighter as a result of the generator not following its schedule in a previous interval.
- Generator Forced Outages and Derates
- External Transaction Schedule Changes, Curtailments and Checkout Failures
- Generator on OOM Dispatch
- Generator Dispatch In Merit – Includes differences that result from economic dispatch of fast-start units, ARD resources, and non-fast-start units by CTSPE and UDS.

Some of these categories are not straightforward, so they are explained with illustrative examples below.

*Load/Wind Forecast Error vs Timing and Ramp Profiling Inconsistency*

Figure 14 illustrates how the load difference between CTSPE and UDS is quantified for the reason of forecast errors and the inconsistency in scheduling timing and ramp profiling. Similar breakdowns are done for wind resources.

**Figure 14: Illustration of Categorizing Load Difference between CTSPE and UDS**



The blue squares in the figure indicate forecasted load (plus any adjustment by the operator) in CTSPE at each quarter-hour interval (i.e., :00, :15, :30, and :45). The yellow circles represent CTSPE load in our metric for each 5-minute interval.<sup>71</sup> Unlike CTSPE that runs regularly every 15 minutes, UDS tends to run at irregular intervals. The illustration in the figure assumes that UDS runs for the interval at :00, :10, :20, :30, :40, and :55 and the black diamonds represent forecasted load (plus any adjustment by the operator) in UDS for these intervals. Similarly, the red circles represent UDS load in our metric for each 5-minute interval.<sup>72</sup>

We assume that changes in load forecasts between sampling points are linear, therefore, the dashed blue line connecting blue squares is the assumed load forecast profile curve in CTSPE. Likewise, the dashed black line connecting black diamonds is the assumed load forecast profile curve in UDS. Then, at each 5-minute interval  $i$ , the load MW differential in our metric is broken into the following three components:

$$\begin{aligned} \text{MW differential}_i &= \text{Load}_{i\text{CTSPE}} (\text{yellow circle}) - \text{Load}_{i\text{UDS}} (\text{red circle}) \\ &= [\text{Interpolated Load}_{i\text{CTSPE}} (\text{blue dashed line}) - \text{Interpolated Load}_{i\text{UDS}} (\text{black dashed line})] \\ &\quad + (\text{Load}_{i\text{CTSPE}} - \text{Interpolated Load}_{i\text{CTSPE}}) \\ &\quad + (\text{Interpolated Load}_{i\text{UDS}} - \text{Load}_{i\text{UDS}}) \end{aligned}$$

The first component represents the difference between the blue dashed line and the black dashed line in the figure, which is categorized as “Load Forecast Error” in our evaluation. The remaining two components represent differences due to different timing and ramping in CTSPE and UDS, which are grouped into the “Schedule Timing and Ramp Profiling” category.

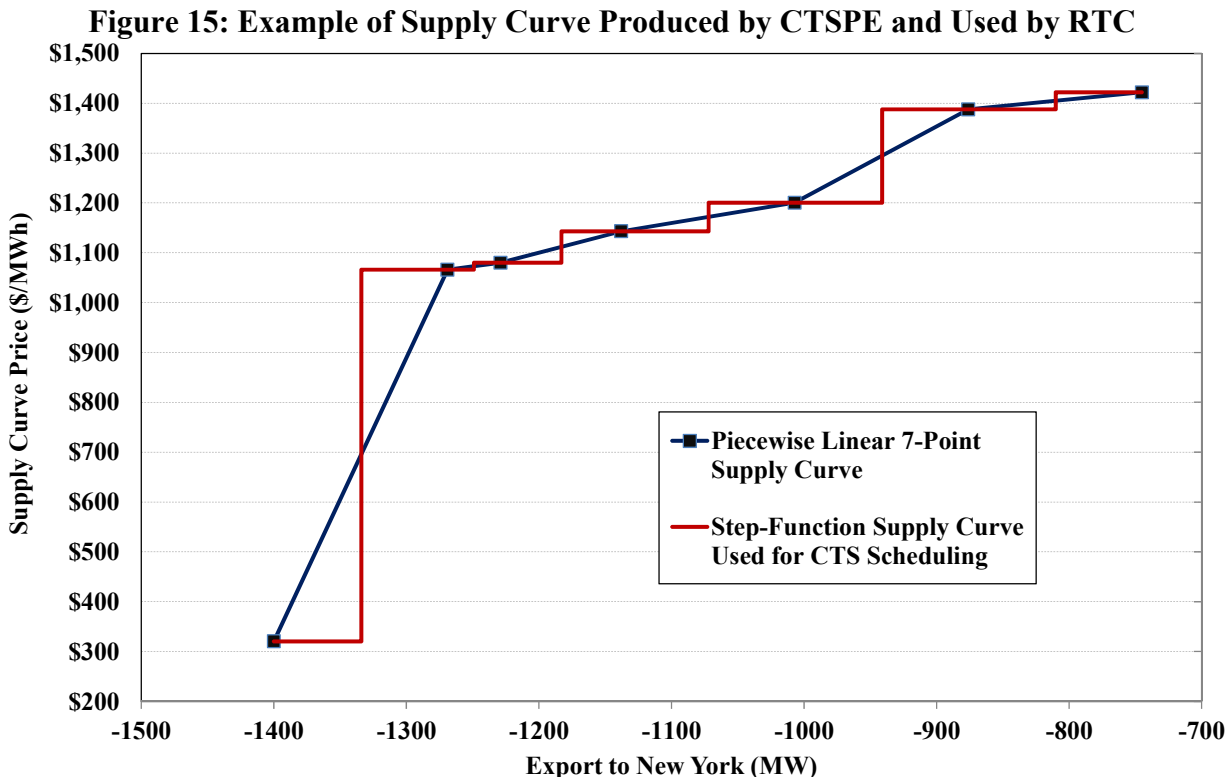
#### *External Transaction Timing and Ramp Profiling Inconsistency*

Each CTSPE run has price forecasts for seven scenarios based on seven different interchange levels over its CTS interface between NYISO and ISO-NE, then an approximated step-function curve based on these seven price/quantity pairs is generated and used in NYISO’s RTC for scheduling CTS transactions at the New England border. This is illustrated in Figure 15.

In the figure, the blue squares show the seven price/quantity pairs that CTSPE produces. The blue line connecting these seven squares represents a piecewise linear supply curve at the New England border, while the red step-function curve is actually used by RTC.

<sup>71</sup> For the purpose of this evaluation, each CTSPE run is associated with three 5-minute intervals. For example, the CTSPE schedules at :15 are used for three 5-minute intervals at :15, :20, and :25.

<sup>72</sup> An approved UDS run can be associated with two or more 5-minute intervals, as the scheduling and pricing outcomes from that UDS run are fed into the LMP Calculator (“LMPc”) to calculate real-time LMPs for these intervals.



Since CTS transactions are scheduled based on the red step-function curve, the cleared quantity normally does not coincide with one of the seven scenarios in CTSPE. In our metric calculation, we use information from the CTSPE scenario that has the closest NY/NE interchange level to the RTC schedule.

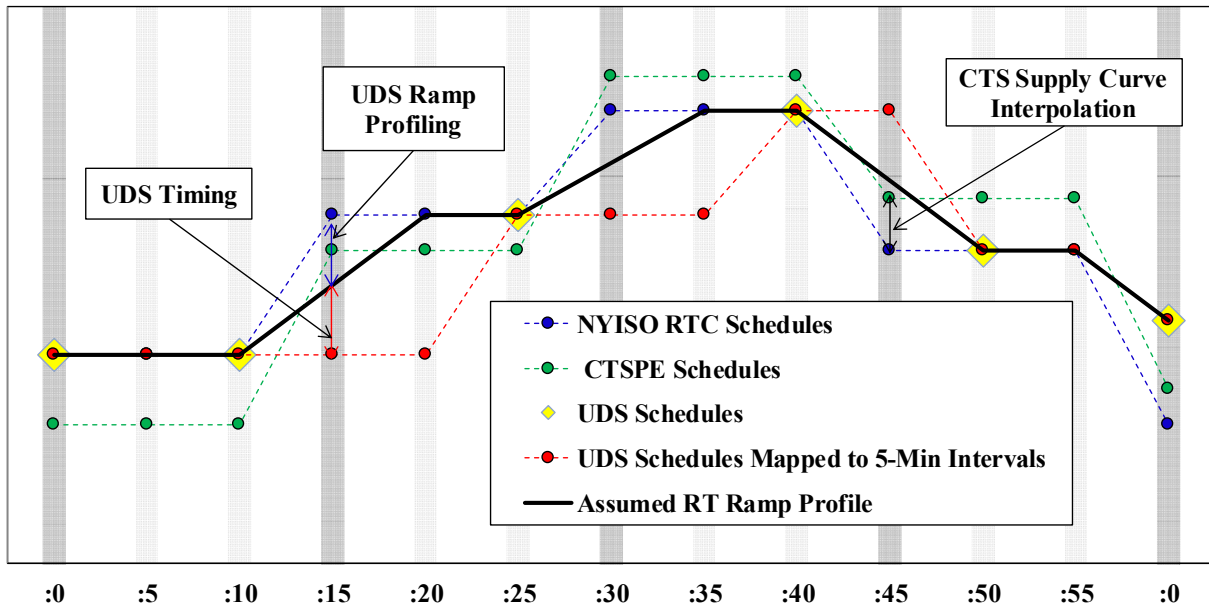
Figure 16 illustrates several categories in our evaluation metric for CTS transactions. The first category measures the effect of different ramping assumptions used in CTSPE (and RTC) and UDS. In UDS, transactions are assumed to move over a 10-minute period from one scheduling period to the next. The 10-minute period goes from five minutes before the quarter-hour to five minutes after. The black line in the figure illustrates such an assumed ramping profile. On the other hand, CTSPE (and RTC) assume that transactions reach their schedule at the quarter-hour, which is five minutes earlier than UDS. These are illustrated by the blue and green circles in the figure. The difference between the blue circles and the black line, “UDS Ramp Profiling” in the figure, results from the difference in ramping assumptions.

The second category is related to the timing of UDS runs. Since UDS runs at irregular intervals and clearing results from one UDS run may be used for multiple 5-minute real-time intervals. In the figure, UDS runs for the intervals at :00, :10, :25, :40, and :50 (represented by yellow diamonds). The red circles represent UDS results mapped to 5-minute intervals. For example, UDS results at :25 are used for three 5-minute intervals at :25, :30, and :35. If UDS is executed for the two intervals at :30 and :35, the two associated red circles will move up on to the black

line. The difference between the black line and the red circle, “UDS Timing” in the figure, results from the timing of UDS runs.

The third category measures the difference between RTC schedules and CTSPE schedules (from the chosen scenario as explained above in Figure 15). This is represented by the difference between blue circles and green circles, “CTS Supply Curve Interpolation” in the figure.

**Figure 16: Illustration of Categorizing CTS Interchange Difference in CTSPE and UDS**



Therefore, at each 5-minute interval  $i$ , the CTS MW differential in our metric is broken into the following three components as mentioned above:

$$\begin{aligned}
 \text{MW differential}_i &= \text{CTSMW}_{i\text{CTSPE}} \text{ (green circle)} - \text{CTSMW}_{i\text{UDS}} \text{ (red circle)} \\
 &= \text{CTSMW}_{i\text{RTC}} \text{ (blue circle)} - \text{RT Ramp (black line)} \\
 &\quad + \text{RT Ramp (black line)} - \text{CTSMW}_{i\text{UDS}} \\
 &\quad + \text{CTSMW}_{i\text{CTSPE}} - \text{CTSMW}_{i\text{RTC}}
 \end{aligned}$$

The first two components are grouped into the “Schedule Timing and Ramp Profiling” category for CTS resources. The third component is reported under “External Transaction Schedule Changes” category.

Similar categorization is done for hourly-scheduled transactions at other external interfaces except that:

- RTC schedules are replaced with GCA (which is ISO-NE’s real-time commitment engine) schedules; and

- The third component does not result from “CTS supply curve interpolation”. Rather, it reflects schedule changes as neighboring markets (especially Quebec and New Brunswick) update their clearing results with ISO-NE.