ANALYSIS GROUP

Energy Security Improvements Impact Assessment

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April 2020

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Glossary of Terms

Abbreviation	Definition
CMR	Current Market Rules
DA LMP	Day-Ahead Locational Marginal Price
DA energy	DA energy award (forward position resulting from day-ahead energy market)
DA energy option	DA energy option (as defined under ESI)
DFO	Distillate fuel oil
EIR	Energy Imbalance Reserves
ESI	Energy Security Improvements
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FER	Forecast Energy Requirement
FRM	Forward Reserve Market
GCR	Generation Contingency Reserves
LDC	Local Distribution Companies
NEPOOL	New England Power Pool
RER	Replacement Energy Reserves
RFO	Residual fuel oil
RT LMP	Real-time Locational Marginal Price

Energy Security Improvements Impact Assessment

I. Executive Summary

ISO New England ("ISO-NE") is proposing new market rules intended to address gaps in the current marketplace that have contributed to concerns about the region's ability to handle ongoing and persistent fuel security challenges.[1] Developing long-term solutions to these challenges is important as the concern may worsen with future changes in system and market conditions given resource retirements and policy-driven shifts in energy supplies.

This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address identified gap in the market; these ancillary services can improve reliability outcomes but are not appropriately incented by the current market rules. By creating these services, the proposal aims to provide technology neutral market signals aligned with the underlying gap in ancillary services needed to address fuel security concerns. In so doing, ESI aims to improve both reliability and market efficiency by better aligning individual market participant incentives with the value of these reliability services.

This report provides an assessment of the impact of these proposed rules, providing both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. Quantitative analysis is based on simulation of the New England day-ahead and real-time energy markets. Using these simulations, impacts are calculated as the difference in market outcomes with and without the ESI market rules changes in effect. Our quantitative analysis estimates the ESI proposal's expected impacts under particular scenarios, while also demonstrating how ESI would be expected to change market outcomes, including the mechanism through which it would improve incentives for resources to provide energy security that improves system reliability.

Our assessment reaches a number of key findings about the expected impacts of ESI, which we summarize below. These findings reflect both the results of both our quantitative analysis and our qualitative assessment, accounting for both economic and analytic considerations.

1. ESI would create strong financial incentives for resources to maintain more secure energy supplies (e.g., higher levels of energy inventories) and generally improve their ability to deliver energy supplies in real-time. These incentives are created primarily through two channels. First, resources that supply day-ahead energy ("DA energy") are compensated with Forecast Energy Requirement ("FER") payments for helping to meet the FER in the day-ahead market. These FER payments represent a new revenue stream, paid in addition to the day-ahead locational marginal price ("DA LMP"), that compensates resources for their contribution to meeting the FER. Second, the new ESI products allow resources that do not sell DA energy,

[1] The authors would like to thank the following Analysis Group, Inc. employees for their assistance with modeling and research as part of this project: Kathryn Barnitt, Tyler Farrell, Leigh Franke, Henry Lane, Danny Nightingale, and Abiy Teshome.

but are able to deliver energy in real-time to meet certain reliability needs, to be compensated for providing these services.

Our quantitative analysis focuses on the incentives for units with stored fuel tanks to expand inventory and refuel more aggressively, and for natural gas units with no on-site storage to make contractual fuel arrangements in advance of winter. ESI's incentives may also impact other decisions affecting the availability of real-time energy supplies, such as plant operational decisions (e.g., preservation of reservoir volumes at hydropower units), plant investment decisions (e.g., dual fuel retrofits) and resource entry and exit decisions.

Consistent with its market-based design, ESI's incentives are greatest during periods when energy security risks are most severe, thereby creating the strongest price signals when energy needs are greatest. These incentives to improve deliverability will also be largest for those resources with the greatest risk of having fuel inventories reduced to the point where supply decisions are constrained. Thus, ESI's incentives efficiently target those opportunities to increase inventory that would provide the greatest value to system reliability relative to their incremental costs. The quantitative analysis demonstrates the alignment of ESI's incremental incentives with these periods of need. Moreover, the analysis shows that these incentives are large in magnitude relative to the costs of certain incremental actions (e.g., incremental fuel storage) and are strongest for those resources best able to improve reliability through cost-effective improvements in their ability to supply energy in real-time.

2. By introducing a new market that compensates resources for providing energy security and imposes significant costs if they cannot deliver energy during stressed conditions, ESI would increase incentives to preserve existing energy inventories. With ESI, resources with energy inventories can be compensated for maintaining reserve energy supplies via their sale of day-ahead energy options ("DA energy options") "backed" by this energy. Under current market rules, resources maintaining reserve energy supplies without a day-ahead position are uncompensated. ESI's design creates these incentives because market participants that sell these services via DA energy options face significant costs if they cannot deliver that energy in real-time during stressed system conditions.

3. Under ESI, the day-ahead market would be more likely to clear energy supplies at (or above) forecasted load and any remaining gap between cleared supplies and forecast load will tend to be smaller. This outcome is a consequence of the day-ahead auction clearing mechanism under ESI, which will implicitly assign a cost to not meeting the FER, as the optimization will procure new ancillary services to cover any such "gap" between the forecasted load and cleared DA energy.

4. ESI's collective impact – including points (1) through (3) – would be expected to improve reliability outcomes, particularly during winter periods. ESI would support delivery of energy in real-time to customer load, supply real-time operating reserves and maintain reliable operations during prolonged system contingencies. Although our quantitative analysis is not designed to precisely analyze system reliability, it quantifies certain aspects of fuel system operations to demonstrate ways in which ESI can reduce stress on fuel systems relied on for energy delivery. The analysis shows that incremental inventoried energy incented by ESI would reduce use of the natural gas pipeline system during tight market conditions, increase aggregate fuel oil inventories, and reduce the rate at which fuel supplies are depleted under stressed conditions. These results are consistent with more reliable electricity system outcomes, particularly during periods of greater fuel system stress.

5. ESI would be expected to improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory reduces energy production from less efficient suppliers and higher cost fuels. Improvements in market efficiency to meet customer loads are expected through improved energy deliverability in tight market conditions, which helps to address the underinvestment in energy security under current market rules (identified as the "misaligned incentives" problem in ISO-NE's "Energy Security Improvements" White Paper) and more efficient unit commitment to meet real-time operating reserves.[2] Under stressed conditions, production costs are conservatively estimated to fall by $19 million and $36 million for the cases evaluated. These reductions in production costs are separate from the improvements in reliability that ESI would also be expected to create.

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While generating these efficiency and reliability benefits, the ESI proposal is also expected to have consequences for payments by load and net revenue to resource owners in the ISO-NE energy markets. **Table 1** provides the estimated changes in total payments during the three winter months for each winter Central Case.

Table 1. Summary of Impacts to Total Payments for Winter Cases

	Frequent Case		Extended Case		Infrequent Case	
Product / Payment	**Payments ($Million)**	**ESI % Change**	**Payments ($Million)**	**ESI % Change**	**Payments ($Million)**	**ESI % Change**
Change in Energy & RT Operating Reserves	-$183	-4.5%	-$214	-7.8%	-$41	-2.4%
Net DA Ancillary Services	$66		$32		$15	
FER Payments	$250		$113		$61	
Change in Total Payments	$132	3.2%	-$69	-2.5%	$35	2.0%

With ESI, aggregate payments by load (to suppliers) would be expected to increase during periods when stressed market conditions are uncommon or infrequent. In the winter months, the estimated change in payments is $35 million over the 3-month winter in the Infrequent Case. In the non-winter months, the estimated changes in payments is $89 million or $125 million (depending on the severity of non-winter market conditions).

Under stressed market conditions, total payments by load (to suppliers) could increase or decrease. The impact on payments under stressed conditions depends on a combination of factors, including the nature of the stressed conditions (e.g., frequency and duration of stressed conditions) and the amount of incremental energy inventory incented by ESI, as this inventory can lower energy prices, particularly during stressed market conditions. In the winter months, this results in an increase in payments of $132 million in the Frequent Case, and a decrease in payments of $69 million in the Extended Case.

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2 ISO New England, Energy Security Improvements: Creating Energy Options for New England, April 15, 2020 ("ESI White Paper").

Overall, aggregate customer payment impacts are modest relative to all ISO-NE markets. Annual impacts range from $20 million to $257 million annually, combining individual winter and non-winter Central Cases, representing a 0.2% to 2.1% increase in total customer payments.

Aggregate impacts to supplier net revenues tend to be the opposite of payments by load. Increased revenues to resource owners generally translate into increased net revenues, although there are some increased costs associated with ESI implementation (e.g., increased fuel inventory holding costs). Thus, in general, increased payments by customers would generally translate into increased net revenues to resource owners, while decreased payments by customers would generally translate into decreased net revenues.

Impacts on net supplier revenues vary across resource types. Net revenue impacts vary across resource types, although direction of these impacts under particular market conditions (i.e., whether net revenues increase or decrease) is generally the same across different resource types.

Estimated changes in payments (and generator net revenues) reflect only changes in energy and ancillary services market outcomes, and do not consider impacts on other wholesale markets such as the Forward Capacity Market ("FCM") or Forward Reserve Market ("FRM").

II. Introduction

ISO-NE is proposing new market rules intended to address a number of gaps in the current marketplace that have contributed to on-going concerns about the region's ability to maintain the necessary fuel security for reliable operations, particularly as the region's fuel and electricity infrastructure evolves in response to policy and market forces. This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address these gaps. The proposal develops day-ahead ancillary service products to address identified gaps in energy supplies that can improve reliability outcomes but are not currently incented by the market. By creating these services, the proposal also aims to improve efficiency by better aligning individual market participant incentives with the region's need for energy supplies during tight market conditions.

This report provides an assessment of the impact of these proposed rules. It provides both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. This information has been developed through a consultative process, with input from both ISO-NE and New England Power Pool ("NEPOOL") stakeholders. Preliminary results were shared with NEPOOL stakeholders in a series of presentations that also provided information on the research approaches, data and assumptions we intended to use. Through this process, we received feedback from stakeholders on these approaches, data and assumptions, and incorporated this information into our assessment, when appropriate. We also received requests for quantitative analysis of impacts under particular assumptions that were considered when developing the set of Scenarios that we analyze in our scenario analysis.[3] Our final set of Scenarios addresses a large fraction of these requests and reflects subsequent communications with stakeholders about which requests were the highest priority among scenarios identified in written requests.

A. Assignment

Analysis Group has been asked to develop an Impact Assessment for the ESI market rule changes being proposed by ISO-NE. Our Impact Assessment is designed to provide both quantitative and qualitative assessment of the likely impacts of the ESI proposal to provide ISO-NE and stakeholders with information about possible impacts of the proposed rule changes (relative to current rules), including the potential efficiency and reliability benefits, costs, impact on consumer payments, and other changes relevant to policy goals. In particular, our Impact Assessment provides information on changes to customer payments and production costs; changes to incentives to market participants to take steps to improve their ability to supply energy in real-time; changes to fuel system operational outcomes that have implications for system reliability; and other expected energy market impacts.

Our assessment includes quantitative analysis of the impacts of the ESI proposal on energy market outcomes based on market simulations. Rather than trying to evaluate expected outcomes across a wide range of probability-weighted scenarios, this work both evaluates particular deterministic winter scenarios, and

[3] "Energy Security Improvements (ESI) Impact Assessment - Extension Priorities." NESCOE. October 15, 2019. "Scenario Request for Impact Assessment for Long-Term Energy Inventory Security Proposal." Massachusetts Attorney General's Office. August 6, 2019.

illustrates particular mechanisms by which ESI may change market outcomes, drawing on particular examples from the model simulations. Our assessment does not consider impacts to other New England markets, including the FCM and FRM.

B. Overview of Energy Security Improvements

ISO-NE is proposing the ESI market rule changes to address persistent fuel security concerns within the New England region that create adverse risks to reliable system operations. Developing robust long-term solutions is important as these challenges may become more significant with future changes in system conditions given resource retirements and policy-driven shifts in energy supplies. These fuel security concerns were a focus of an Order from the Federal Energy Regulatory Commission ("FERC"), which directed ISO-NE to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[4] The ESI market rule changes are proposed in response to this directive.

The ESI proposal is summarized in the ESI White Paper, and is defined further in subsequent presentations to the NEPOOL Markets Committee. ESI is designed to provide a long-term, market-based and technology-neutral solution to existing concerns with the region's markets, including persistent energy security challenges. To this end, the ESI proposal introduces multiple new ancillary services to address different gaps in the current services procured day-ahead and thereby improve reliability outcomes. Through new payment streams and the financial positions it creates for market participants providing the new ancillary services, ESI creates new incentives for resource owners to take actions (e.g., procuring fuel) to increase the likelihood that they are able to deliver energy in real-time. These new services can also better align resource incentives to maintain fuel security with the benefits these arrangements provide. In particular, the ESI White Paper identifies a "misaligned incentives" problem that occurs when a resource's private incentives to improve its ability to provide energy supply in real-time do not align with society's incentives for market participants to undertake such arrangements.

Specifically, ESI proposes to introduce the following three new ancillary services, and compensate resources that provide each accordingly:

- ***Energy Imbalance Reserves ("EIR") and Forecast Energy Requirement ("FER").*** ESI imposes an FER, which requires that EIR be procured to cover the gap, if any, between (1) the expected real-time load, as estimated prior to clearing the day-ahead market, and (2) the supply of physical energy cleared in the day-ahead market. At present, ISO-NE ensures reliable operations if there is a gap between the forecast load and the cleared day-ahead physical energy supply through supplemental reliability commitments that are made after the day-ahead market is run. However, this service (through ramping capability from committed units, reliance on fast start units, or incremental commitments, if needed) is currently uncompensated.

  Along with the EIR, ESI would also compensate day-ahead physical energy supply that contributes to meeting the FER. The FER price paid to DA energy is set to either (1) the (marginal) savings from

[4] ISO New England Inc., 164 FERC ¶ 61,003 at P 2 (2018).

supplying DA energy, calculated as the avoided cost of a DA energy option to meet the FER constraint, or (2) the (marginal) cost of supplying additional DA energy (e.g., the difference between marginal supply and demand offers) if cleared DA energy exactly meets the forecast load. At this price, the resource is no worse off from supplying DA energy as compared to supplying EIR, thus providing incentives to offer supply of DA energy and DA energy options at the respective opportunity costs.

- ***Generation Contingency Reserves ("GCR").*** With GCR, ESI provides an approach to procuring, in the day-ahead energy and ancillary services market, the resource capabilities that ISO-NE currently designates and maintains in real-time for operating reserves. This ensures that adequate energy supplies are available to supply these operating reserves, thus allowing operators to meet system contingencies in real-time. In addition, day-ahead procurement of real-time operating reserves would improve market efficiency by ensuring that day-ahead commitments reflect a co-optimized procurement of energy and operating reserves.

- ***Replacement Energy Reserves ("RER").*** The RER seeks to ensure that there are sufficient energy reserves to maintain reliable system operations in the event of an extended resource contingency. In particular, the RER is designed to allow real-time operating reserves to be restored after a system contingency.[5]

Together, procurement of these new ancillary services would improve the system's ability to respond to unanticipated, real-time stressed system conditions that create adverse reliability risks, and would provide price signals to the market that incentivize market participants to take steps to improve fuel security and resource performance.[6]

Except for FER payments to resources that supply DA energy, the new ancillary services would be delivered through provision of "real" energy options. Market participants would submit offers to supply an energy (call) option, specifying the minimum price they are willing to be paid to accept the energy offer obligation. A standardized, uniform energy option will be procured for all ESI products. The energy option is structured as a call option, where, in exchange for this up-front payment, the supplier pays (credits) load the difference between the real-time locational marginal price ("LMP") and a pre-determined strike price, if that difference is greater than zero. That is, the per-MWh payment – or "closeout cost" – is:

Closeout cost = maximum (0, real-time LMP – strike price).

Ability to supply each of the ESI products depends on each resource's physical energy capabilities to ensure that the option for energy supply being procured is consistent with the underlying real-time need associated with each product. Thus, the ability to supply GCR products reflects the same operational requirements as real-time operating reserves; the ability to supply EIR reflects operational requirements consistent with the

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5 ISO New England, "Energy Security Improvements: Market-based Approaches, Replacement Energy Reserves," January 14-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx

6 Mark Karl and Peter Brandien, Letter to NEPOOL Markets Committee, December 4, 2019. https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_i_memo_re_how_market_improvements_address_fuel_security.pdf

energy being available within 60 minutes, and the ability to supply RER products reflects longer-lead time (90- or 240-minute) operational capabilities.

Under ESI, ISO-NE will co-optimize the procurement of energy and energy options in the day-ahead market to clear supply offers and demand bids, ensure load balancing, and meet new ESI product constraints. While the proposal introduces new products to the day-ahead market, market-clearing of New England's real-time energy and ancillary services would be unchanged.

III. Approach to Impact Assessment

The Impact Assessment reflects both *quantitative analysis* of changes in outcomes from our economic model and *qualitative assessment* of factors not captured by our quantitative analysis. Quantitative impacts are estimated through a simulation of the New England day-ahead and real-time energy markets (including real-time reserves). The production cost model used to simulate the market will be run two times, once using assumptions consistent with market-clearing under Current Market Rules (CMR), where the new ancillary services are not procured in the day-ahead market, and a second time using assumptions consistent with market-clearing under the ESI, where these new ancillary services are procured.[7] ESI's impacts are estimated to be the difference in outcomes between the ESI case and the corresponding CMR case, as this difference represents the (positive or negative) incremental impacts associated with the market rule change. For example, our estimate of ESI's impact on total customer payments is the total payments under the ESI case minus the total payments under the CMR case. Using this approach, we develop estimates of changes in economic outcomes (e.g., prices, production costs, total payments) and changes in system operational outcomes reflective of reliability impacts (e.g., fuel inventory, reserve shortages).

The quantitative analysis is performed by evaluating individual scenarios under assumed market conditions. These scenarios do not represent forecasts or predictions of future outcomes. Instead, these deterministic scenarios are intended to represent potential market and resource conditions that might reasonably arise in the future, and provide an indicative snapshot of ESI's impacts under these conditions. The scenario analysis also does not provide an indication of ESI's probability-weighted expected impacts, as the model does not weight the likelihood that the different scenarios being evaluated, or the many potential scenarios that are not evaluated, will occur.

The quantitative analysis considers different Cases reflecting potential future market and system conditions, and different levels of stress on the fuel supply systems. We consider both winter month and non-winter month cases. Much of our quantitative analysis focuses on ***impacts in winter months***, because energy security currently poses the most pressing challenges to New England in the winter months. However, we also evaluate ESI's impacts during non-winter months as the ESI proposal introduces these new day-ahead ancillary services across all twelve months for a combination of reasons, including energy security concerns that could become more pronounced during non-winter months as the region's resource mix and energy infrastructure

7 Throughout the report, the acronym CMR is used when referring to the specific "case" we analyze, while the phrase "current market rules" is used when referring to the ISO-NE energy market's current market design and rules.

evolves, and the possibility that the "misaligned incentives" problem would otherwise reduce market efficiency during non-winter months.[8]

For the winter months, we evaluate three levels of market and system stress based on historical New England winters:

- ***Frequent Stressed Conditions ("Frequent Case").*** The Frequent Case is based on market conditions from the winter of 2013/14. This winter experienced multiple, shorter periods with fuel system constraints, driven in large part by numerous cold-snaps.
- ***Extended Stressed Conditions ("Extended Case").*** The Extended Case is based on market conditions from the winter of 2017/18. This winter experienced one extended period with fuel system constraints, which occurred during a long cold-snap in late December and early January.
- ***Infrequent Stressed Conditions ("Infrequent Case").*** The Infrequent Case is based on market conditions from the winter of 2016/17. This winter experienced particularly mild temperatures and no periods of stressed conditions. One indicator of the mildness of these conditions was that day-ahead natural gas prices at Algonquin Citygate never exceeded $13 per MMBtu over the entire winter.

Impacts in non-winter months are evaluated through two Cases, also based on historical non-winter periods:

- ***Severe Stressed Conditions ("Severe Case").*** The Severe Case reflects more stressed market conditions (e.g., high customer loads), based on the 2018 non-winter months.
- ***Moderate Stressed Conditions ("Moderate Case").*** The Moderate Case reflects typical non-winter conditions without periods of more stressed market conditions, based on the 2017 non-winter months.

These Cases provide information on ESI's economic impacts but do not analyze changes in operational metrics that signal improvements in reliability.

While these winter and non-winter Cases are based on historical periods, load and supply conditions are updated to be more consistent with a future year, assumed to run from December 1, 2025 to November 30, 2026. More specifically, they assume a future resource mix that includes current resources in the fleet and announced retirements and fuel (natural gas) availability consistent with current infrastructure and potential retirements (e.g., Distrigas LNG terminal in Everett, Massachusetts). Other assumptions are based on actual market conditions from the historical periods identified above, including loads, certain resource supplies (such as, wind and solar), natural gas prices and availability of natural gas supplies to the electricity sector (given demand from natural gas Local Distribution Companies ("LDCs")).

Our core analysis – or Central Case – evaluates each of these different market conditions (or levels of system stress) in substantial detail, and the results from these Cases are presented in **Sections IV.A** (winter) and **IV.B**

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8 ISO New England, "Energy Security Improvements," ISO Discussion Paper, Version 1, April 2019.

(non-winter). In addition, we analyze multiple Scenarios in **Section IV.C** that alter particular assumptions related to ESI market design, system resources, fuel supplies and costs.

The Central Cases are not intended to represent "business as usual" cases, but plausible future *scenarios* consistent with the current mix of resources and infrastructure in New England. Consistent with this scenario-based approach to our analysis, we do not assign probabilities to each Case, particularly as these Cases represent a subset of the range of possible future market conditions. It is beyond the scope of this analysis to attempt to assign probabilities to these Cases. While there is substantial weather data available that might support the assignment of probabilities to particular weather conditions, ESI impacts reflect not only factors driven by weather conditions, such as electricity market loads and natural gas supplies, but many other factors, such as the retirement and entry of energy infrastructure, that will depend on market, regulatory and policy outcomes that are difficult to forecast.

A. Production Cost Model: Overview

The New England energy market is analyzed using an integrated production cost model that captures key features of the markets to provide reasonable measures of the impacts of the proposed ESI rules. This model incorporates both day-ahead and real-time energy markets, real-time ancillary service markets for 10- and 30-minute operating reserves, opportunity cost bidding options allowing market participants to account for limited energy, and the proposed ESI day-ahead ancillary services.[9]

The production cost model simulates market clearing consistent with a competitive wholesale energy market. The model maximizes social welfare[10] as reflected in demand bids and supply offers, while satisfying other physical system requirements, including supply-load balancing and procurement of various ancillary services in day-ahead and real-time.

The model simulates market-clearing across all 24 hours of each day. Each day's market is simulated sequentially, with the outcomes of real-time market clearing in each day affecting the supply offers in subsequent days, given limited fuel supplies and the constraints associated with fuel replenishment. Day-ahead and real-time market-clearing is coordinated, in the sense that the consequences of supply decisions in real-time affect day-ahead offers in a manner consistent with market participants' reasonable expectations about inventories when submitting day-ahead offers.

Figure 1 provides a schematic for the model's structure. The model's core includes algorithms to replicate market clearing in the New England day-ahead and real-time energy markets. The algorithms account for key features of the markets as they operate under current market rules and as they would operate under ESI, including supply-load balancing and ancillary service constraints. The algorithms account for some, but not

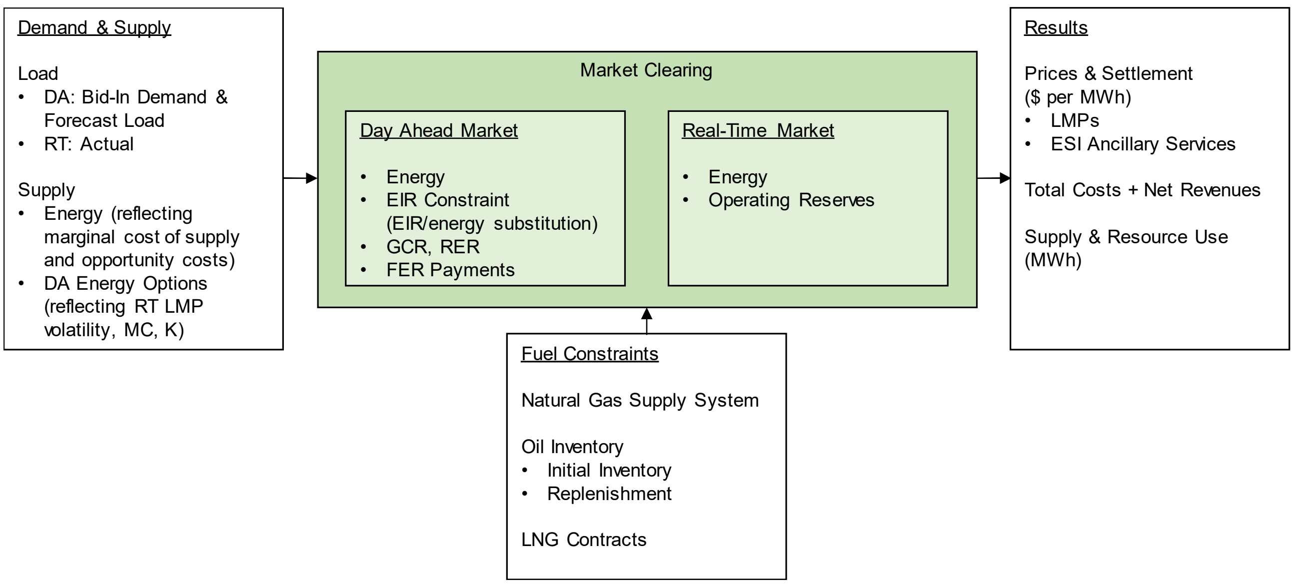
9 The analysis in this report does not account for locational constraints and therefore simulates a single DA and RT LMPs for the entire region. As a result, when the report refers to the DA or RT LMP, this is the price all energy supply is paid, and energy options are settled at the RT LMP.

10 Social welfare in the day-ahead market reflects the sum of bid-in demand net of the sum of supply offers for energy and ancillary services needed to meet all day-ahead market constraints, accounting for any penalty factors associated with failure to meet particular constraints. This welfare calculation is discussed in more detail in the appendix.

all, resource operational limitations. For example, the model does not account for unit commitment logic, through which certain intertemporal parameters (for example, start-up costs, minimum run-time, and minimum down-time) are accounted for. Thus, our analysis will not quantify all factors that determine energy and ancillary service positions, or all changes in production costs associated with ESI.

Information on supply offers and demand bids are inputs to the model based on each Case's assumptions. In addition, information about fuel constraints is captured by the model, including natural gas supply available to the electricity sector, fuel oil inventories, and any forward LNG contracts. These fuel constraints are dynamically determined through the modeling of fuel inventory, including replenishment. The model provides outputs, to be used for analysis, including product prices (LMPs, ancillary service prices), day-ahead and real-time supply of energy and ancillary services, and fuel inventories.

Figure 1. Overview of Modeling Approach: Model Components



B. Day-Ahead and Real-Time Markets

Within the **day-ahead market module**, market participants submit supply offers to sell both energy and DA energy options and demand bids to purchase quantities of energy. The model clears these offers to sell and bids to buy such that welfare is maximized, supply equals demand, and, in the ESI cases, ESI ancillary service constraints are met over all hours of the day.[11] Offer prices and quantities for each resource are dynamically bid into the model based on case and resource-specific assumptions (e.g., fuel prices, variable operating costs) and the results of market clearing in prior days (e.g., including an opportunity cost as appropriate to account for limited fuel inventory). Bid prices for load reflect the quantity of energy that the market (including physical load and virtual load) is willing to purchase at different energy prices.

[11] As we describe below, the model includes shortage prices for all day-ahead and real-time ancillary services consistent with current market rules or the ESI proposal.

The **real-time market module** is designed similarly, with three key differences. First, this module includes real-time operating reserves instead of ESI products, consistent with the current market design, which would be unchanged under ESI. Second, all offers in the real-time market reflect actual fuel inventory available given previous days' generation and refueling, rather than assuming fuel inventory based on the resource's day-ahead awards. Third, electricity demand is inelastic (i.e., set at a fixed level in each hour).

The model evaluates outcomes in winter months and non-winter months. In general, model operations, assumptions and data are similar for winter and non-winter months, but we identify differences when they arise in the descriptions below.

1. Day-Ahead Energy Market Demand

We analyze three future winter cases for the year 2025/26, reflecting Frequent, Extended, and Infrequent stressed conditions. These Cases are based on weather and load patterns from the three-month (December through February) winters of 2016/17, 2017/18, and 2013/14, respectively. We also model two future non-winter cases, Moderate and Severe, based on weather and load patterns from the nine-month non-winter period (March through November) for 2017 and 2018, respectively. In each Case, weather patterns and other factors affect both electricity demand and natural gas supply available to the electricity sector, given LDC (non-electricity) demand. Gas supply is discussed in **Section III.C.1**.

Bids to buy DA energy are based on historical bid-in demand from physical load, virtual trades, and pumped storage. Bid-in demand is modeled as a sloped demand curve (with discrete quantities at different price levels) in each hour, so the market awards hourly DA energy positions to the demand bids (and supply offers) that maximize welfare while meeting the various energy balance and ancillary service constraints. The day-ahead load forecast and actual real-time load (demand) are based on historical data from the respective year for each Case. These data provide the hour-to-hour load patterns that are used in the future cases.

To calculate future (2025/26) hourly values for the load forecast, day-ahead demand bids, and real-time energy load, we scale the historical values so that future bids and loads are consistent with the forecast peak load and forecast adjusted total energy from the 2019 CELT Report for the year 2025/26.[12] For each Case, **Table 2** lists the historical base year used as the basis for hour-to-hour load patterns, and the forecast peak load and adjusted total energy values (from CELT) used as the benchmarks for future loads.

[12] ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report). Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (ISO New England, 2018)

Table 2. Summary of Load by Future Winter Case

Season	Case	Base Year	CELT Scenario	Peak Load	Total Energy
Winter	Infrequent Case	2016/17	20/80 Peak Load Unmodified total energy for 2025/26	19,250 MW	31,525 GWh
	Extended Case	2017/18	50/50 Peak Load Predicted total energy for 2025/26 +1%	19,436 MW	31,840 GWh
	Frequent Case	2013/14	80/20 Peak Load Predicted total energy for 2025/26 +2%	19,837 MW	31,156 GWh
Non-Winter	Moderate Case	2017	50/50 Peak Load Unmodified total energy for 2026	24,315 MW	88,287 GWh
	Severe Case	2018	80/20 Peak Load Predicted total energy for 2026 +1%	25,412 MW	90,053 GWh

Day-ahead bid-in demand varies between the CMR and ESI cases. In the CMR cases, bid-in demand is based on historical bid-in demand, calibrated so that the market clears at an energy price consistent with historical day-ahead energy market outcomes (that in principle are consistent with expected real-time market outcomes), while also accounting for changes in demand from historical to anticipated future levels. In the ESI cases, bid-in demand also accounts for the shift in demand that would occur due to the impact of ESI on energy prices and the market response given arbitrage opportunities. We discuss this further in **Section III.B.5**.

2. Day-Ahead Ancillary Service Product Demand for ESI Runs

In the runs where ESI is assumed to be in effect, the model simulation clears supplies of day-ahead energy options to meet the new ESI constraints. This simulation co-optimizes the market-clearing of all products in the day-ahead market, including energy and each of four ESI products – GCR10, GCR30, RER, and EIR.[13] We model hourly requirements for GCR10, GCR30, RER, and EIR.

For ***GCR***, we model GCR10 and GCR30, but do not account for separate spinning and non-spinning requirements for GCR10. The model assumes the required quantities of GCR10 and GCR30 are 1,600 and 2,400 MW, respectively, levels that are consistent with the ESI proposal. While, in practice, these values will vary from day to day depending on each day's first- and second-contingencies, we expect this variation to be sufficiently small that assuming a fixed requirement is unlikely to meaningfully affect estimated impacts. Committed GCR10 quantities cascade, such that they can contribute to meeting both the GCR10 and GCR30 requirements.

For ***RER***, we model a single RER product, combining the RER90 and RER240 products.[14] The model assumes a fixed requirement of 1,200 MW in each hour for both RER90 and RER240. This requirement cascades with the GCR10 and GCR30 requirements, such that the combined requirement of GCR10, GCR30, and RER is 3,600 MW.

[13] The model collapses the two RER products proposed by ISO-NE into a single product for simplicity.

[14] This modeling assumption will therefore compensate all resources that provide the RER90 or RER240 product at a single price that is more in line with the RER240 product. In practice, it may therefore understate the compensation to resources that provide the RER90 product in hours when this product would be priced above the RER 240 product.

For ***EIR****,* rather than assuming a fixed value, the requirement is modeled endogenously as a function of cleared energy supply – which is solved simultaneously – and the ISO-NE load forecast, which is fixed in each hour. We describe this constraint in further detail below, in **Section III.B.5**.

ESI product awards are limited by resource-specific characteristics given each resource's ability to provide each ESI service. Offline capability reflects a unit's Claim10, Claim30, "Claim60", or "Claim240" capability to provide GCR10, GCR30, EIR, and RER, respectively.[15] A unit with a DA energy award can also supply ESI products through the unit's ramp capability, and the model's logic is designed such that this ramp capability can receive an ESI award only when it is also supplying DA energy (in quantities consistent with a plant's minimum load).[16] Data on Claim10, Claim30, "Claim60", and "Claim240" capability are provided by ISO-NE.

The analysis also assumes ESI awards are limited by the availability of fuel to physically support the DA energy option. At the resource level, cleared DA energy option quantities are limited to the resource's available energy inventory. For example, oil-only units will only sell a DA energy option if they have fuel in inventory to cover this position. At the system level, the total supply of ESI products awarded to gas-only resources is limited by the hourly supply of natural gas available through the pipeline system to the electricity sector.

The prices for each ESI product is limited by administratively determined penalty factors. Penalty factors cap the price for each ESI product, including circumstances when there is insufficient supply of eligible DA energy options to meet a particular requirement. **Table 3** provides the modeled penalty factors (per MWh), which align with ISO-NE's proposed market design:[17]

Table 3. ESI Day-Ahead Ancillary Service Penalty Factors

Ancillary Service Product	Penalty Factor (per MWh)
RER	$100
GCR30	$1,000
GCR10	$1,500
EIR	$2,929

3. *Day-Ahead Energy Market Supply*

Our analysis assumes the operation of resources currently in the New England market, defined to be resources that have cleared the 13th Forward Capacity Auction (FCA 13) but have not submitted retirement notifications for FCA 14. This assumes the retirement of the Mystic 8 and 9 generation facilities that currently have a cost-

15 In this report, Claim10, Claim30, Claim60, and Claim240 represent the capacity in MW that a unit can provide from an offline state in 10, 30, 60, and 240 minutes, respectively. While Claim10 and Claim30 are currently defined parameters that correspond with the procurement of operating reserves, Claim60 and Claim240 are not currently defined (thus, placed in quotations), but are used to reflect the analogous parameters for 60- and 240-minute capability to deliver energy within 60 and 240 minutes, respectively.

16 For simplicity, resources are modeled as either "claim" (cold start) or "ramp" (must be providing energy) eligible.

17 The penalty factor for RER is set to $100 per MWh, which corresponds to the penalty factor for RER240. The penalty factor for RER90, which is not modeled in this analysis is currently proposed to be set to $250 per MWh.

of-service contract.[18] **Table 4** summarizes the mix of resources by resource-type, reporting total capacity by category for the winter months, based on winter claimed capability. The analysis of non-winter month relies on summer claimed capability. The fleet of resources are assumed to be the same under CMR and ESI, although certain gas-only resources are categorized differently – under ESI these resources have a forward LNG contract, whereas under CMR they do not.

Table 4. Future Resource Mix Scenarios, Winter Months, Capacity (MW)[19]

	CMR	ESI
Natural Gas Fired Resources		
Natural Gas with Oil Dual Fuel	7,928	7,928
Natural Gas Only	8,603	7,987
Natural Gas with LNG Forward Contract	0	616
Natural Gas Fuel Cell	21	21
Oil Only	6,304	6,304
Coal	535	535
Nuclear	3,344	3,344
Hydroelectric Resources		
Hydro: Pondage	1,241	1,241
Hydro: Run-of-River	749	749
Pumped Storage	1,778	1,778
Wind Resource		
Land Based Wind	1,401	1,401
Offshore Wind	832	832
Solar	1,671	1,671
Biomass/Refuse	849	849
Battery Storage	458	458
Price Responsive DR	285	285
Total	**35,998**	**35,998**

Energy-supplying resources are modeled as either **optimized resources** or **profiled resources**.

Optimized resources submit energy market offers in each hour at a price reflecting their marginal cost of production. These resources include fossil fuel resources, biomass, fuel cells, price responsive demand, and imports.[20] Resource offers generally reflect the same cost factors in winter and non-winter months, and the total day-ahead supply each resource can clear in the market – including DA energy and ESI products – is limited to its seasonal claimed capability, which can vary between summer and winter. In addition, the quantity

18 164 FERC ¶ 61,022, Order, July 13, 2018

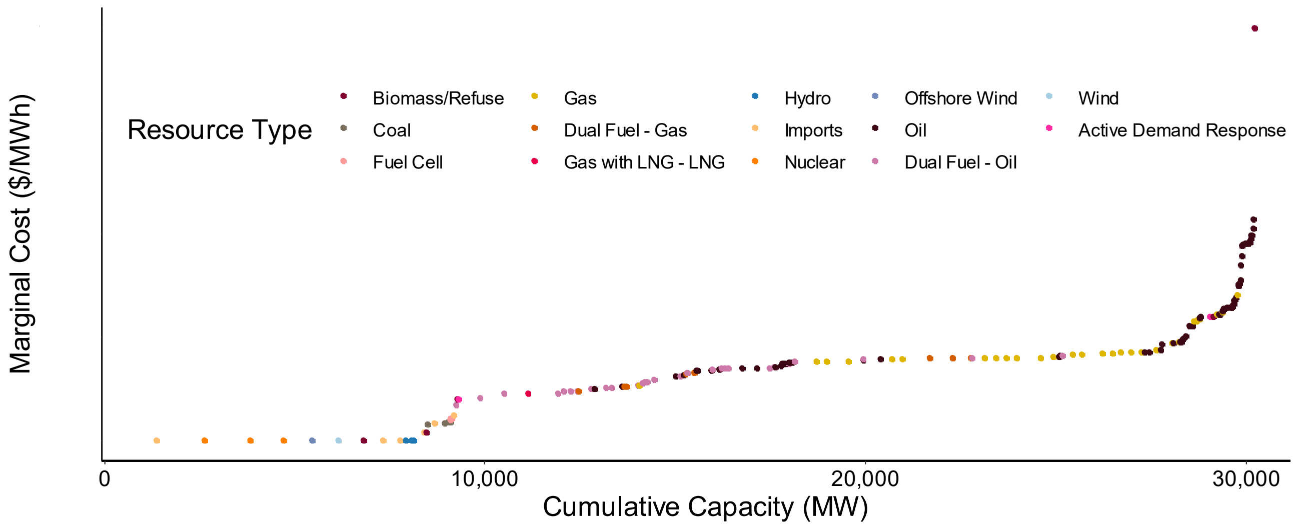
19 Capacity is based on FCA 13 results (excluding resources that have submitted FCA 14 retirement notifications). Dispatched units assume seasonal claimed capability and profiled units assume nameplate capability from the 2019 CELT Report. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore). The winter month analysis assumes winter claimed capability and the non-winter month analysis assumes summer claimed capability. Additional information on assumed retirements, dispatched units, and profiled units is provided in the appendix.

20 The full set of dispatched resources are: Gas, Oil, Coal, Nuclear, Biomass/Refuse, Imports, Fuel Cell, and Price Responsive Demand.

each resource can supply is also adjusted for its average forced outage rate. For example, a 100 MW unit with a 5% forced outage rate is assumed to be capable of supplying 95 MW across all hours. Market-clearing also reflects resource-specific offers for supplying a DA energy option, as discussed further in **Section III.B.4**.

Supply offers from optimized resources are used to create a supply curve, as illustrated in **Figure 2**. As we describe in further detail below, supply from some resources may be limited by fuel inventories and the capacity of fuel systems. These limits include resource-level constraints due to limited fuel oil inventories and limited LNG contracts, and system-level constraints due to fixed natural gas pipeline transmission infrastructure.

Figure 2. Illustrative Resource Energy Supply Curve



Each resource's energy supply is offered at a price based on its marginal cost of supplying energy. The marginal cost of supply can reflect production costs and opportunity costs. Marginal production costs for fossil resources include costs for fuel, variable operations and maintenance ("O&M"), and emissions. These costs reflect resource-specific characteristics, including fuel type, heat rate, and emission rates.[21] Dual-fuel (gas/oil) resources are modeled such that units offer supply using the fuel with the lowest marginal cost, subject to constraints on fuel supply. The model does not consider unit-level permit requirements that may impose certain operational limitations, including limitations on the use of alternate fuels.[22]

Unit-specific production costs, heat rates, and emissions rates underlying units' offers are based on data from SNL Financial as of August 2019. Units not yet in service are assigned unit characteristics from similar, recently-built units. The model simplifies unit offers by assuming supply is offered in one block rather than multiple blocks. This assumption simplifies certain modeling complexities that are beyond the project's scope,

21 For additional information on data sources, please see Section III.B. Emission costs for Massachusetts Global Warming Solutions Act compliance are $9.67 per metric ton based on the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.

22 The model assumes that all resources with dual-fuel capability generate power using the fuel that allows generation at the lowest marginal cost. We do not account unit-specific environmental permit requirements that may limit the circumstances in which certain units with dual-fuel capability can operate on their alternate fuels.

but appear unlikely to meaningfully affect the analyses' estimates of ESI's impacts. The model accounts for certain unit operational limitations. Units that can supply DA energy options or real-time operating reserves through ramp capability can only provide such ancillary service supply when also supplying energy.

For resources with limited fuel inventory, particularly oil-fired resources, offers reflect both the resource's production costs and its opportunity costs. Because of these resources' limited fuel inventory, supplying energy in one hour may limit a resource's ability to supply energy in a different hour, in the same day or in a subsequent day. **Opportunity cost adders** allow a resource to account for this opportunity cost, and increase the likelihood that limited energy supply is used in the highest-priced hours. ISO-NE recently changed market mitigation procedures to provide automated calculation of opportunity costs that allow oil-only and dual-fuel resources to facilitate inclusion in their market offers.[23]

In our analysis, opportunity cost bid adders are calculated using a similar methodology to that incorporated into the opportunity cost models that ISO-NE makes available for market participant use. The adder reflects expected net revenue earned by a resource's "last" unit of energy over a three-day, multi-day horizon when hourly net revenues are sorted from highest to lowest. The net revenues of a resource's last unit of energy is calculated assuming that the resource only provides energy during the most profitable hours and that the resource has imperfect information about the fuel inventories of other resources and future energy prices. A resource only has an opportunity cost in situations where fuel is limited: if there is enough fuel to operate as expected for all profitable hours in the future time horizon at-issue, the resource has an opportunity cost of zero because it is assumed that using energy now will not preclude it from producing energy in the future.[24]

Imports are categorized as either price-responsive or non-price-responsive based on analysis of historical import offer patterns. Price-responsive imports are modeled using an offer curve calibrated against historical pricing, while non-price-responsive imports are modeled as a fixed quantity of imported energy in every hour.

Profiled resources are assumed to supply energy and ancillary services at levels consistent with historical supply patterns. For these resources, we rely on historical patterns because these resources would otherwise be particularly complex to model (e.g., pumped storage units) or their output is generally based on exogenous factors (e.g., solar and wind variable renewables).[25] For existing resources, we assume that each resource supplies energy and ancillary services consistent with its historical supply. For new resources (i.e., cleared in an FCA, but not yet operational) with a profiled technology, we assume supply is consistent with existing resources in the market. For variable renewable generation, including wind and solar generation, base year generation output is scaled to future levels consistent with new capacity that has cleared the FCA but is not yet operational. For example, given 2017-2018 historical total solar nameplate capacity of 941 MW and assumed future total solar nameplate capacity of 1,671 MW, the solar output for each hour is scaled up by

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[23] Lowell, Jonathan, "Opportunity Costs and Energy Market Offers (Phase 1), ISO's Proposal to Estimate Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations," October 9-10, 2018. https://www.iso-ne.com/static-assets/documents/2018/10/a7_presentation_opportunity_costs_and_energy_market_offers.pptx

[24] For more information on the opportunity cost adder calculation, see the appendix.

[25] The full set of profiled resources are: Battery Storage, Hydro - Pondage, Hydro - Run of River, Hydro - Weekly, Pumped Storage, Solar, Offshore Wind, and Onshore Wind.

77.5% (1,671 MW/941 MW = 1.775). Offshore wind generation profiles are based on historical wind buoy data from ISO-NE.

For profiled resources, we assume that each resource supplies GCR10 and GCR30 at levels consistent with historical supply of 10- and 30-minute real-time operating reserves. If the total quantity of historical cleared operating reserves exceeds the assumed GCR10 and GCR30 requirements (which occurs in some hours), the excess supply is used to satisfy other requirements introduced under ESI.

4. Day-Ahead Energy Option Offers

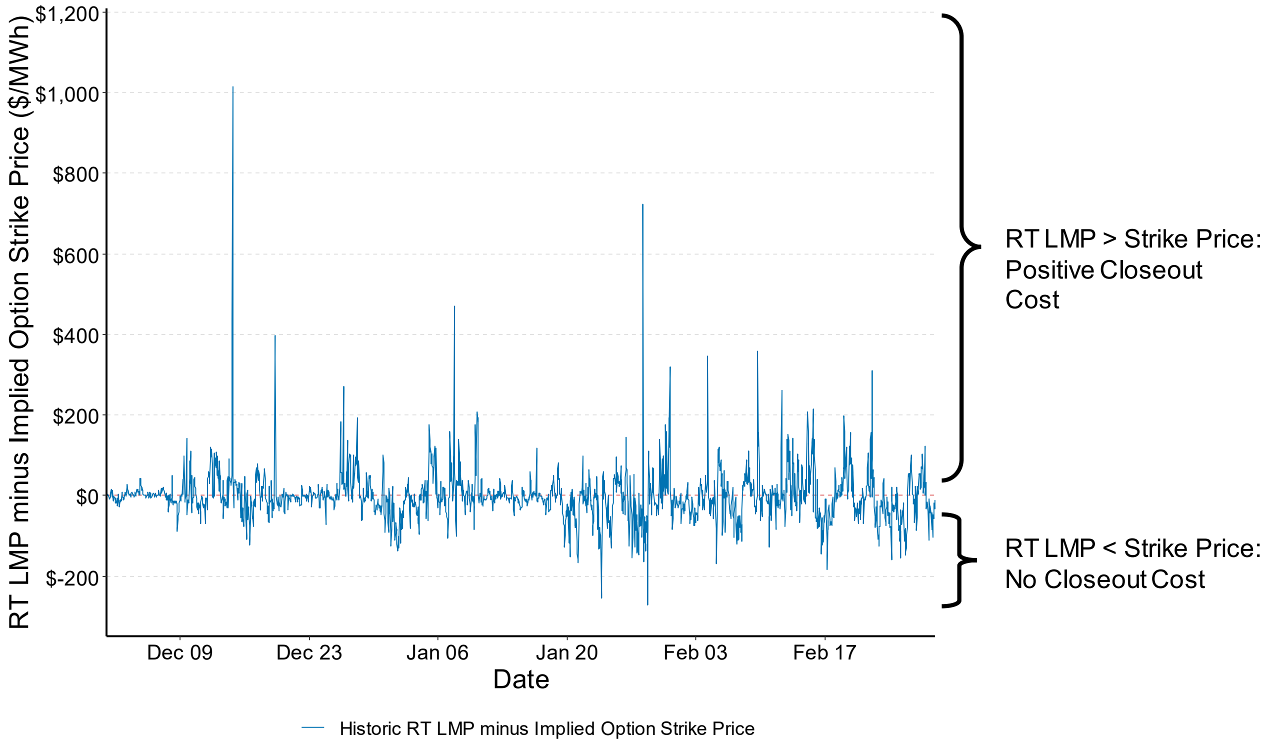
Under the ESI proposal, market participants submit offers to supply energy options into the day-ahead market. While the ESI proposal includes multiple day-ahead ancillary service products, the same underlying commodity – a DA energy option with the same strike price and that settles against the same real-time LMP ("RT LMP") – is used to satisfy each of the new GCR, RER, and EIR services. Thus, ***each resource submits an offer(s) for one commodity – the DA energy option – in each hour, even though the market participant may be able to supply multiple ESI products.***

While the financial settlement of each energy option product is equivalent, market-clearing prices for ESI products can differ if the optimization selects higher-priced option offers to satisfy the requirements for products with more-restrictive eligibility requirements. For example, the GCR10 price may be greater than the prices for other ESI products if resources meeting the more-restrictive 10-minute operational requirement offer options at a higher price. However, under ESI's pricing rules, a more flexible resource that is able to provide multiple ESI products is compensated at the rate that corresponds with the "highest quality" product it can provide.

We estimate supplier offers for DA energy options through a quantitative analysis based on historical market data. The estimated option offer prices reflect the basic financial tradeoff for suppliers if they are awarded a DA energy option. If they are awarded an option, they receive a fixed payment, reflecting the market-clearing price for the ESI product. In return, they agree to pay a settlement (or "closeout") cost, which is a function of the difference between the RT LMP in that hour and the strike price, which is set at a fixed value prior to submittal of option offer prices. When the RT LMPs are higher than the strike price, the option is "in the money" and suppliers must pay the difference between the RT LMP and the strike price. When this difference is zero or negative, the option is "out of the money" and the closeout cost is zero. Regardless of the closeout cost, option suppliers keep the fixed payment earned by writing the option.

Given uncertain RT LMPs, the seller receives a sure payment in exchange for an uncertain (potentially zero) closeout cost. This risky closeout cost is illustrated by **Figure 3**, which shows the difference between the RT LMP and the strike price on each day, where the strike price is set to the hourly historical DA LMP.

Figure 3. Difference between RT LMP and Implied Strike Price, and Corresponding Closeout Cost Winter 2013/14



Note: Strike price is modeled as the historical DA LMP.

Competitive offers for DA energy options will reflect suppliers' willingness to accept the obligation to settle ("close out") at the option's payout terms. In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option closeout, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to sell the option reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. That is, in each hour:

$$DA\ energy\ option\ offer(h)\ = expected\ closeout\ cost(h) + risk\ premium\ (h)$$

This approach differs from the approach commonly taken to estimate the value of options traded in financial markets, which relies on constructing a portfolio (a "replicating portfolio") of financial products that replicates the returns for the option. The options procured through ESI, however, cannot be replicated through a portfolio of thickly traded assets (e.g., forwards and cash positions), as is the case for many options.[26] Thus, valuations

[26] The real options procured through the ESI proposal differ in many respects from financial options for thickly traded assets, such as stocks traded on major exchanges. The underlying asset for the DA energy options – RT energy – is not traded on any open

will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[27]

The analysis (as well as the settlement of the DA energy options) is undertaken using historical RT LMP data rather than using an iterative process based on model output data. The use of historical data provides a robust approach to valuing DA energy options, as the option value is dependent on an actual distribution of real-time energy prices.[28] Future market conditions may differ from historical market conditions, but alternative approaches to estimating expected closeout costs, which are not grounded in historical data, would do no better in addressing such potential differences. Scenario analysis in which the model's assumed risk premiums are varied tests the sensitivity of this assumption on ESI's impacts.

When estimating option offers, the strike price varies by hour and is set at the historical DA LMP in each hour. In practice, of course, the ESI proposal envisions that the strike price will be set through different means, as the DA LMP will not be known when the day-ahead market is run. But for the purposes of our analysis, the historical DA LMP provides a reasonable estimate of the market's corresponding expectations for RT LMPs in each hour. In fact, this strike price would likely be more precise than any metrics available for use to set the strike price, as it is set within the day-ahead optimization rather than before it. **Figure 4** and **Figure 5** provides the distribution of all estimated offers and all cleared offers across all hours in the Frequent Case.

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exchange at present, making it impossible to "replicate" the option through a combination of cash purchases and forwards. Thus, the risk and financial properties of these options will differ from those of more liquid financial assets. To the extent that financial markets developed new products or expanded trading in existing illiquid products, potentially in response to ESI, the methods for pricing options and mitigating option risks could evolve.

27 Cochrane, John and Jesus Saa-Requejo, 1999, "Beyond Arbitrage: Good-Deal Asset Price Bounds in Incomplete Markets."

28 Among available options, the use of historical data is the most robust approach to estimating this distribution, as other approaches would require parametric assumptions without an empirical foundation. **Section III.D.2** provides further detail on, and rationale for, the use of historical RT LMPs for settlement of DA energy options.

Figure 4. DA Energy Option Offer Prices, All Market Offers, Winter Frequent Case

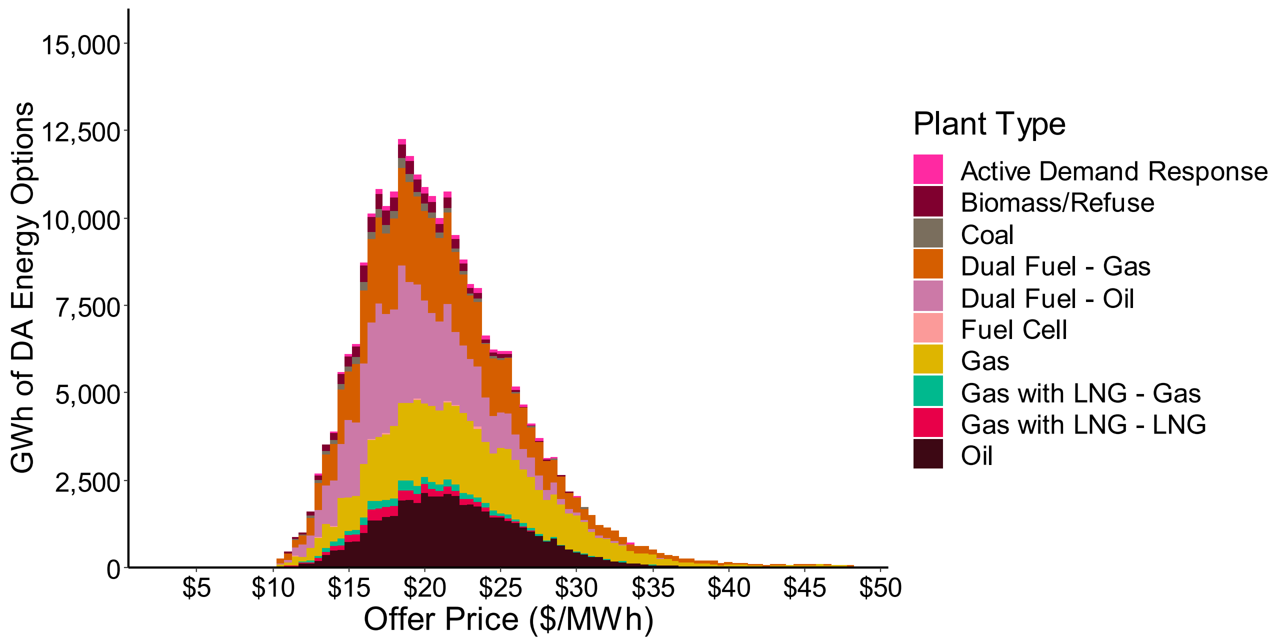
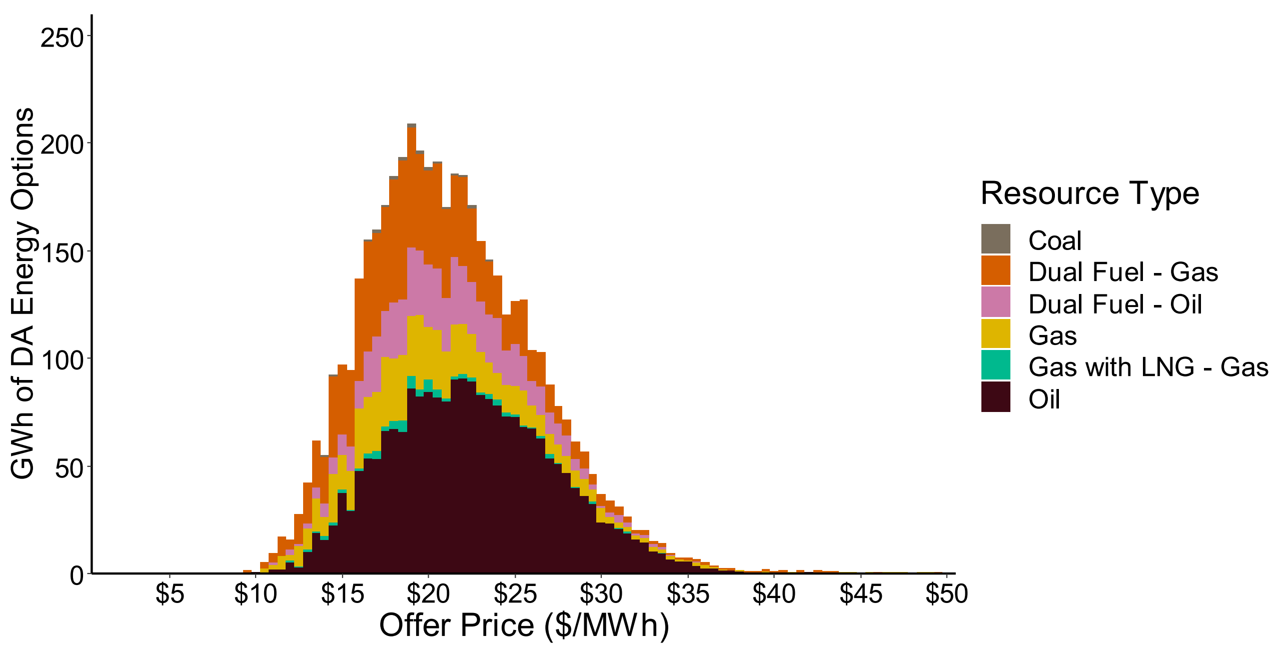


Figure 5. DA Energy Option Offer Prices, Cleared Offers, Winter Frequent Case



Below, we briefly describe our methodology for estimating the offer prices for DA energy options. In the appendix, we describe our methodology in greater detail.

a) Expected Closeout Costs

Expected closeout costs are estimated through a simulation process drawing on historical data from recent winters (2012 to 2018). This simulation process is used to estimate the distribution of RT LMPs (relative to the strike price) in each hour, and then to estimate the expected closeout cost of the option conditional on that distribution. Because the closeout costs of the DA energy option have an asymmetric structure, with positive costs if the RT LMP exceeds the strike price and no cost otherwise, it is necessary to evaluate this distribution to ensure that the expected cost is not understated.

Expected closeout costs are assumed to be uniform across all market participants. While, in reality, there may be differences in market participants' expectations regarding RT LMPs, the challenges associated with estimating these differences in a reasonable manner for each supplier in each hour across all potential market conditions would be significant. Thus, all heterogeneity in DA energy option offers is due to the risk premiums, which differ across resources.

Expected closeout costs are estimated in several steps. First, we develop a single "point estimate" for the difference between the RT LMP and the strike price (i.e., *RT LMP – K*) given hour-specific market and weather conditions. This point estimate is created by estimating a linear regression model for *RT LMP – K* as a function of several variables, including temperature, rolling historical volatility in closeout costs, and various date fixed effects, and then using this model to estimate a single fitted value for each hour based on its observable characteristics.[29] Including these variables in the regression controls for information that would be available to suppliers when forming expectations about closeout costs in order to develop an option offer price in the day-ahead market.

The second step accounts for the statistical uncertainty in our single point estimate. Accounting for uncertainty in the potential values for *RT LMP – K* ensures that expected closeout costs are not understated. **Figure 6** illustrates this effect for a distribution of values of *RT LMP – K*. Because closeout costs are asymmetric, the closeout costs associated with a distribution of values of *RT LMP – K* (the dashed orange line) are equal to zero when *RT LMP – K* is negative. Thus, the average closeout cost estimated over the full distribution is greater than the point estimate, because it accounts for the closeout costs asymmetric distribution. The Monte Carlo simulations we use to estimate the probability distribution illustrated in **Figure 6** are described in greater detail in the appendix.

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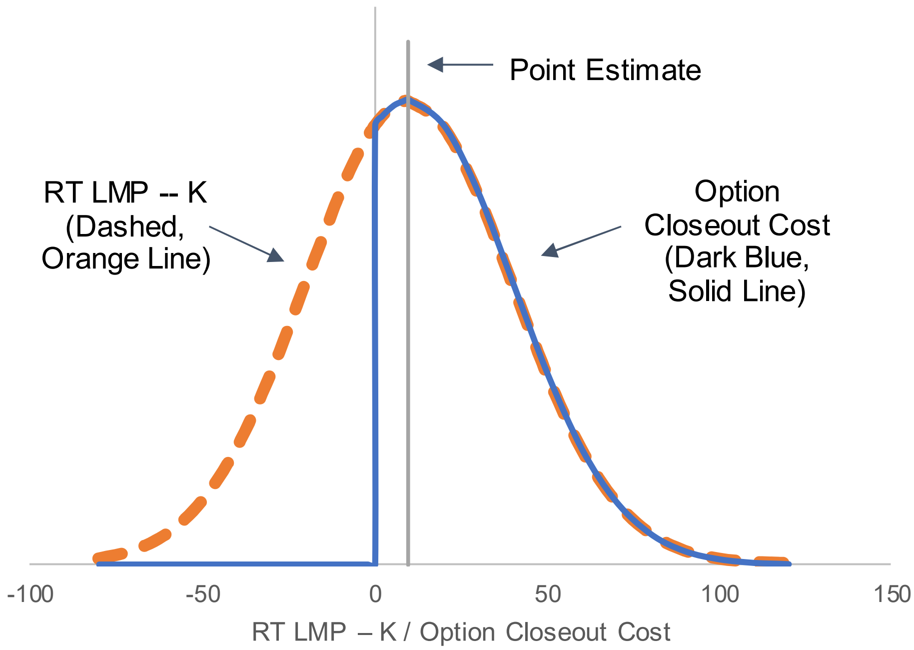
29 The model is fit using data from winter months from December 2012 through February 2018. For the non-winter cases, the same model is fit to data from each of the nine-month periods that comprise the non-winter seasons.

Figure 6. Illustration of Distribution of DA Energy Option Closeout Costs



b) Risk Premium

Our estimates for risk premiums build off risk preferences revealed in the market. In particular, we assume that the risk premiums for taking forward positions in DA energy markets provide information about market participants' willingness to take on a potentially risky forward position. The estimated risk premium component of the DA energy option offer reflects estimates of these forward risk premiums, with adjustments made to account for differences in the respective financial positions (e.g., the relative prices and the relative magnitude of the financial risk). **Figure 7** and **Figure 8** provide the estimated risk premiums for all hourly DA energy option offers and cleared DA energy option offers for the Frequent Case, where ESI is assumed to be in effect. Further details on the methodology we used to estimate the risk premiums is provided in the appendix.

Figure 7. DA Energy Option Risk Premiums, All Market Offers, Winter Frequent Case

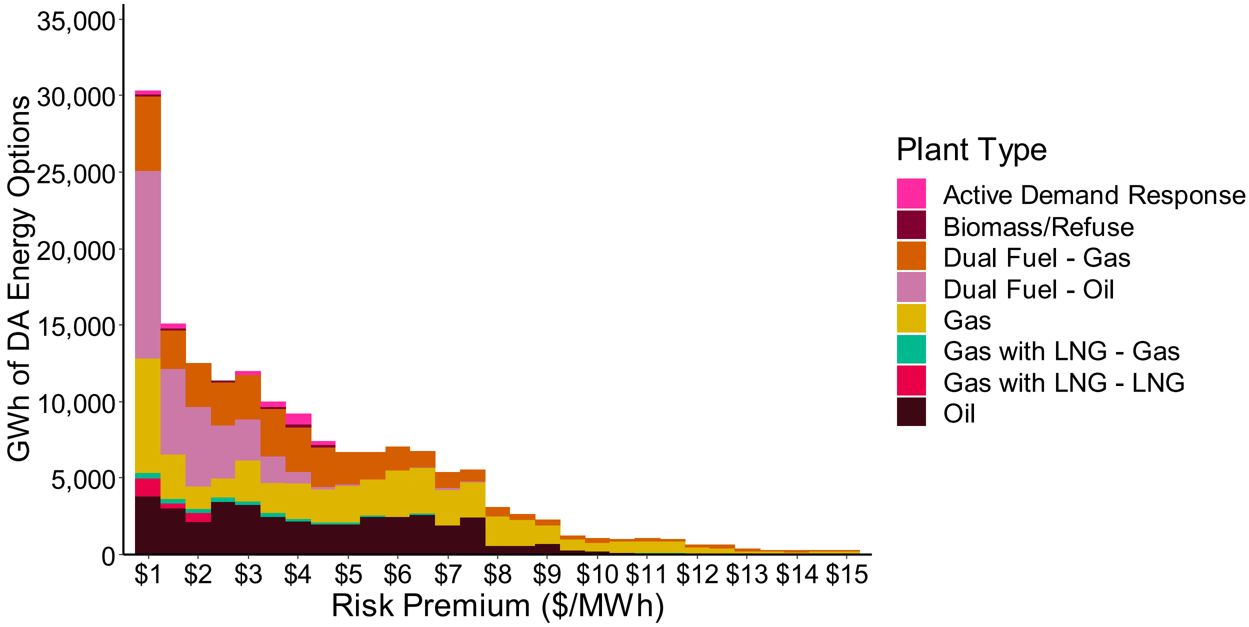
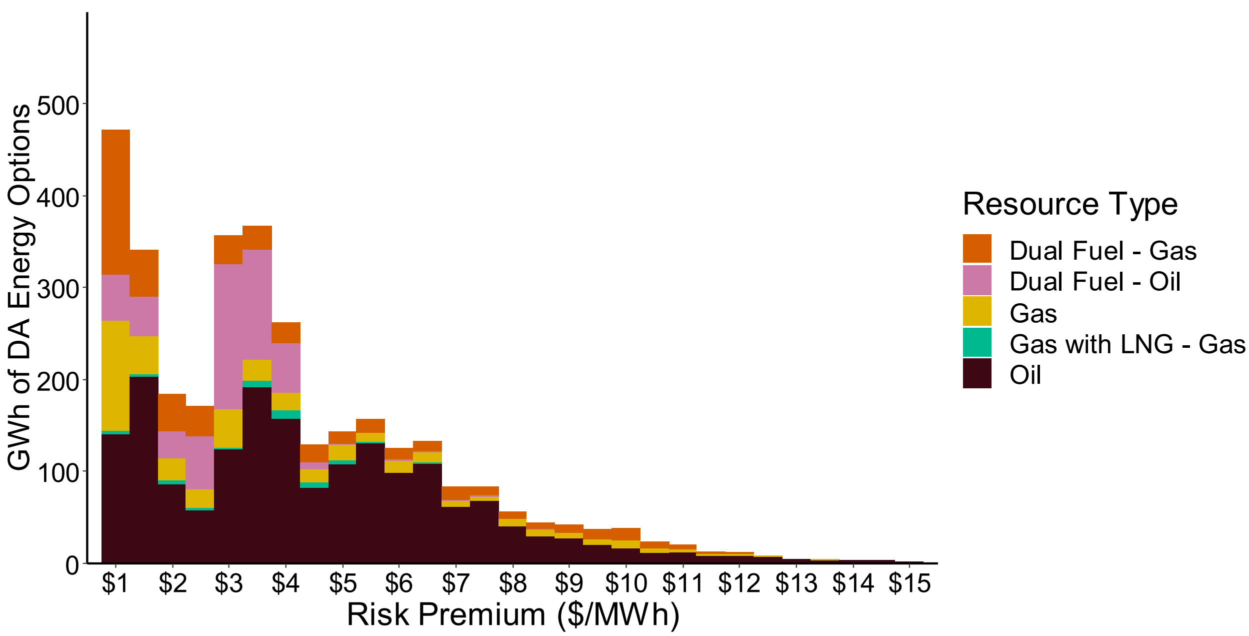


Figure 8. DA Energy Option Risk Premiums, Cleared Offers, Winter Frequent Case

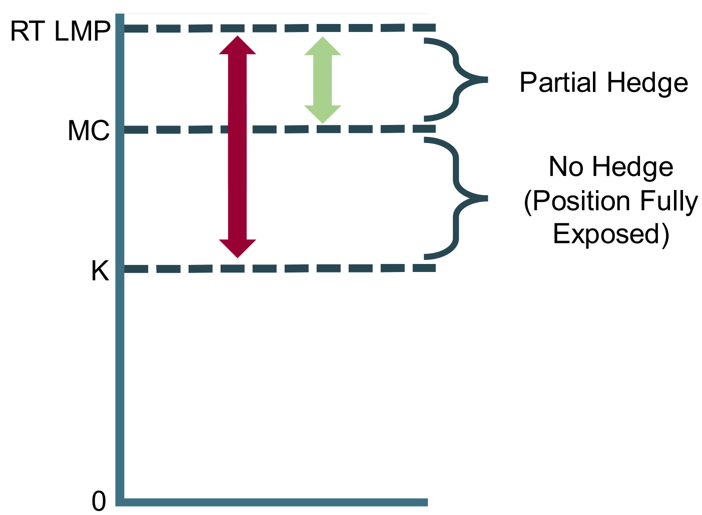


Like any financial option, financial risk is greatest when the underlying commodity prices (in this case, RT LMPs) are more volatile. With higher volatility, there is a greater risk of large closeout costs that can have a variety of follow-on corporate implications (impacts to cash flow, credit ratings, etc.). Thus, we assume that the risk premium is greater under system conditions in which higher levels of RT LMP volatility are expected. However, the impact of a DA energy option award on a supplier's financial risk will depend not only on the magnitude of this risk but also on other market net revenues earned by the supplier and the extent to which these revenues are correlated with the DA energy option's closeout costs.

For valuing the risks associated with selling energy options, an important factor to consider is that closeout costs and supplier revenues in the real-time energy markets will often be negatively correlated. When RT LMPs exceed the strike price, set roughly at the corresponding DA LMP for that hour, this signals that energy is likely needed from resources that did not clear for energy in the day-ahead market. Thus, while suppliers of DA energy options face positive closeout costs when RT LMPs exceed the strike price, they are also more likely to provide energy in real-time and receive incremental real-time energy revenues during these hours. As a result, the resource's ability to provide energy to the system in real-time serves as a hedge for the sale of a DA energy option, as the real-time energy ("RT energy") revenues associated with high RT LMPs may offset the closeout costs during such periods.

The hedge provided by physical energy inventory is greatest when this inventory can be supplied to the market at a lower marginal cost. This point is illustrated by **Figure 9**. Assume that the strike price is *K* and that the DA energy option settles at *RT LMP*. In this case, the closeout cost faced by someone holding a DA energy option is represented by the red arrow. Suppose, however, that this resource can supply RT energy to the market at marginal cost of *MC*. In this case, on a per MWh basis, the option holder earns *RT LMP – MC* in net energy revenues (equal to the energy market revenues it is paid for providing this energy, less the marginal costs of producing it), while paying out *RT LMP – K* in closeout costs. The net result is a smaller net loss of *MC – K* compared to the closeout cost alone (and where this loss does not account for the initial day-ahead payment for selling the option). Thus, the physical energy inventory provides a partial hedge to the DA energy option's risks.

Figure 9. Illustration of Physical Hedge Provided by Energy Inventory to DA Energy Option Risk



As the above example illustrates, the extent to which physical energy inventory hedges the risks of a DA energy option depends on the marginal costs at which that inventory can be supplied. When the marginal costs are low relative to the strike price (e.g., when MC is equal to K), the inventory provides a more effective hedge, whereas when the marginal costs are high relative to the strike price, the inventory provides a more limited hedge. As a result, the financial risks of a DA energy option depend on the resource's marginal costs, given the potential for this energy supply to offset closeout costs when RT LMPs are higher. Thus, we account for the resource's cost of energy supply when calculating risk premiums.

The potential for physical energy inventory to mitigate the financial risk of a DA energy option depends not only on the marginal costs of this supply, but also on operational and intertemporal factors that may limit a resource's ability to supply energy in real-time in response to higher-than-expected RT LMPs. We account for certain operational and intertemporal factors when calculating the risk premium. These factors include:

- ***Performance Risk.*** For all resources, there is the risk that the resource is unable to provide energy during periods of high RT LMPs due to a forced outage or other operational factors (e.g., transmission outage).
- ***Lead Time and Intertemporal Factors.*** Lead times required for a resource to become fully energized and other intertemporal factors may limit a resource's ability to hedge closeout cost risk if these factors limit its ability to deliver energy supply during periods of high RT LMPs to cover the real-time settlement cost of a DA energy option. Similarly, some resources' supply may be limited by inter-temporal factors, as reflected by offer parameters such as minimum run-time and minimum down time.
- ***Fuel Cost Risk.*** Natural gas-only resources face fuel price risk because prices may be higher in the intra-day natural gas markets compared to the day-ahead natural gas market, especially during periods when the RT LMP exceeds the DA LMP, and when trading in supply for delivery to a particular resource may be illiquid.
- ***Start-up Cost.*** Offline resources may incur start-up costs in addition to short-run marginal costs for physical energy supply to cover a DA energy option settlement. This factor considers this incremental cost via an additional risk factor.

These parameters vary across technologies, depending on technology-specific attributes. **Table 5** shows how these factors vary across electricity generation technologies, with more detail provided in the appendix. In the table, a check mark indicates that the category is modeled for the given technology, and the risk premium is increased accordingly. A check with a "+" symbol indicates that the levels modeled are greater, relative to those with just a check.

Table 5. Operational and Intertemporal Factors Accounted for in Estimated Risk Premium

	Operational and Intertemporal Factors (*p*)		Cost Factors (*m*)	
	Performance Risk	Lead Time	Fuel Cost Risk	Start-up Cost
Combustion Turbines				
Gas-only			✓+	✓+
Oil-only, Dual Fuel			✓	✓+
Combined Cycle				
Gas-only	✓	✓	✓	✓
Oil-only, Dual Fuel, LNG Contract	✓	✓		✓
Steam				
Oil-only, Dual Fuel	✓+	✓+		✓

5. *FER Requirement and Payments*

The FER constraint ensures that there are sufficient DA energy awards and options available to meet forecast energy in each interval. With other ESI products (RER and GCR), the quantity procured is largely independent of the quantity of energy procured, as these quantities are set to meet contingencies. However, with EIR, the market clearing algorithm (endogenously) *solves for both the quantity of EIR and the quantity of cleared DA energy*. Specifically, the FER constraint, satisfied through EIR, has the following structure:

EIR = maximum (0, forecast load – cleared physical DA energy supply)

By virtue of this structure, so long as cleared DA physical energy is less than forecast load, additional DA energy supply leads to a direct ("1-for-1") reduction in the quantity of EIR that needs to be procured to ensure that there is energy in real-time to meet the forecast load.

For example, assume that for a given hour, the forecast load is 110 MWh and the cleared physical DA energy is 100 MW. In this case, the EIR is 10 MWh, equal to the difference between the forecast load and cleared physical DA energy. Consider the impact of a 1 MWh increase in cleared DA physical energy from 100 MWh to 101 MWh. With the 1 MWh increase in energy, the total cost of procuring DA energy increases. But, the 1 MWh increase in DA energy reduces EIR by 1 MWh to 9 MWh:

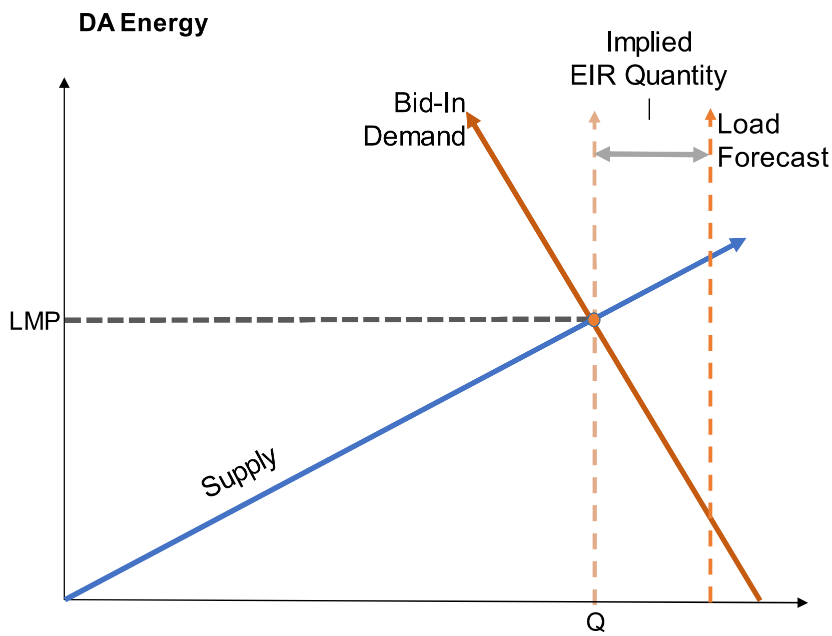
EIR = maximum (0, 110 MWh – (100 MWh + 1 MWh)) = 9 MWh

Thus, if the day-ahead optimization clears 1 MWh of additional physical energy, it will reduce the quantity of EIR by 1 MWh.

When determining the optimal quantity of DA energy and EIR, the optimization accounts for this interaction between the cleared physical DA energy and EIR, which is an inherent element of the ESI design. As a result, when determining the quantity of DA energy that clears the market, the clearing algorithm accounts for the cost sellers incur by providing additional DA energy, the benefit that energy provides to buyers, and the savings associated with a potential reduction in quantity of EIR that is procured.

Under current market rules the day-ahead market does not procure EIR to offset any difference between forecast load and physical energy supplied, and any such costs that would be associated with a shortage are therefore not considered. As such, the DA energy market generally clears at a price and quantity where the supply offer curve and bid-in demand curve intersect. As shown in **Figure 10**, the resulting outcomes can lead to a gap between the quantity of physical energy that clears the market and the load forecast. In **Figure 10**, this gap is represented by the "Implied EIR Quantity".

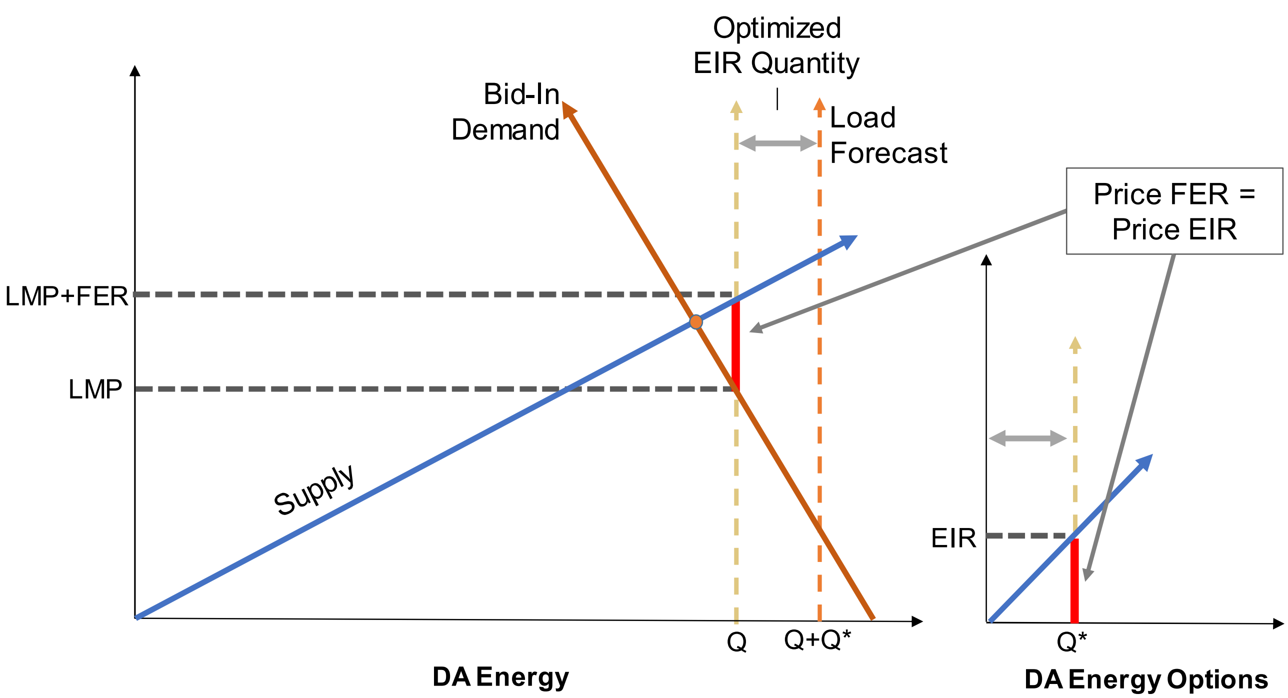
Figure 10. Illustration of the Implied EIR Quantity Under Current Market Rules



Under the ESI proposal, the market-clearing algorithm determines the optimal (least cost) quantity of DA cleared energy and EIR by balancing (on the margin) the loss from additional MW of DA energy with the cost of additional DA EIR energy option MWh. In this tradeoff, the optimization calculates the welfare "loss" of additional DA energy as the *difference* between the social cost of supplying power for energy, reflected by supply offer prices, and customers' demand for power, reflected by demand bid prices for energy. At the intersection of supply and demand (price "LMP" in **Figure 10**), this loss is zero because the cost to supplying this increment is equal to the benefit that demand derives from procuring it. However, once the FER, and the procurement of EIR to satisfy this requirement, is considered under the ESI design, social welfare may not be maximized at this point. In particular, if the market clears the same quantity of DA energy as under current market rules, a large quantity of EIR would be required to meet the load forecast, which could be costly as the market would procure DA energy options to make up this EIR gap.

Figure 11 illustrates the market outcome after co-optimization of DA energy and EIR under ESI. With the co-optimization of DA energy and EIR, total social surplus is maximized by increasing the quantity of DA energy procured, which in turn decreases the EIR quantity, until the marginal loss from procuring DA energy equals the cost of DA energy options, on the margin. In **Figure 11**, the marginal loss from procuring DA energy is reflected by the difference between the Supply and Bid-In Demand curves at the market clearing quantity of energy, *Q*, represented by the red vertical line. Physical generators supplying DA energy are paid a total price of LMP+FER, the cost of the marginal energy supply offer. In addition, a quantity of EIR (*Q**) clears to ensure that the sum of *Q* and *Q** equals the load forecast. The quantity of DA energy and the price paid for this energy increase compared to the market-clearing quantity and price under current market rules.

Figure 11. Illustration of Interaction between DA Energy and EIR under ESI



Consistent with the ESI market design, the model solves for both the quantity of DA energy and the quantity of EIR while accounting for this interaction between the DA products. Thus, the analysis provides estimates for the increases in cleared DA physical energy supplies that are expected under ESI due to this co-optimization, which will reduce the gap between cleared DA physical energy supplies and the ISO-NE load forecast, relative to current market rules.

Our analysis also accounts for expected market responses to these shifts in cleared DA energy supply due to ESI co-optimization of ESI products, including these EIR interactions. In particular, the model accounts for adjustments to bid-in demand that would be expected in response to the reduction in DA LMP, illustrated by comparison of **Figure 10** and **Figure 11.** Because there has been no change in the underlying expected RT LMP under ESI, if the model did not include such an adjustment, there would be a persistent and predictable difference between DA and RT LMPs that could offer a profitable trading (arbitrage) opportunity where participants buy at the (lower) DA LMP and then sell at the (higher) RT LMP. Faced with such an opportunity to earn positive profits, market participants will increase their bid-in demand for DA energy until their trading activity has competed away these expected profits. To account for this trading activity, we adjust (increase) bid-in demand so that the resulting DA LMPs remain generally consistent with the expected RT LMPs. As a result, DA LMPs remain roughly in-line with *expected* RT LMPs, while DA LMPs and RT LMPs vary from day-to-day given the usual idiosyncratic variation in weather, loads and other factors between day-ahead and real-time markets.

6. Real-Time Markets

The real-time energy market functions similarly to the day-ahead market described above. Resources offer into the real-time energy market based on their marginal and opportunity costs. The market clears to ensure that demand is met, supply and demand are balanced, and real-time operating reserve constraints are met, while co-optimizing the procurement of energy and operating reserves. The model includes a single 10-Minute Reserve product that combines spinning and non-spinning reserves and 30-Minute Operating Reserves product. Consistent with current market rules (which ISO-NE is not proposing to change with ESI), resources do not provide bids for these reserve products; instead, reserves are co-optimized to minimize energy offer costs based on the Claim10 and Claim30 capabilities of off-line resources (or ramp capabilities for on-line resources). Consistent with their GCR counterparts, the requirements in each hour for TMR and TMOR are assumed to be fixed at 1,600 MW and 2,400 MW, respectively, and quantities of MW provided toward TMR cascade into the TMOR requirements. Reserve Constraint Penalty Factors are set at $1,500 (for TMR) and $1,000 (for TMOR).

As is generally consistent with actual market operations, the RT energy market clears at inelastic (fixed) load levels, and does not reflect the clearing of supply offers and demand bids, as is the case in the day-ahead market. The model's realized RT load levels differ from both its cleared DA energy demand and the forecast load, reflecting normal daily variation and market uncertainty. We do not model differences in resource availability between day-ahead and real-time markets, although several scenarios explore the impact of shocks to resource availability due to sudden unexpected outage contingencies.

C. Fuel Inventory Constraints

Fuel availability has a significant impact on the energy supplies that certain types of fossil-fuel resources can deliver in real-time during winter months. The model accounts for both natural gas system delivery constraints and resource-specific fuel oil constraints. As described earlier, offer prices from fuel-oil resources with limited fuel supplies reflect these constraints through the opportunity cost adders that support the delivery of this energy when it is most valuable. In addition, the model assumes that resources do not supply energy and/or ancillary services in the day-ahead or real-time markets if these positions cannot be supported by physical inventory available at the start of the day. While these fuel constraints are modeled in both the winter and non-winter months, given the lower level of LDC natural gas demand these constraints generally have no material impact on market outcomes during non-winter months.

1. Natural Gas Market Assumptions

Natural gas is used extensively for residential and commercial heating in New England during the winter and is drawn off interstate gas pipelines for residential distribution by LDCs. Gas-fired power plants draw their fuel supply off the same interstate pipelines but generally have interruptible (i.e., less firm) contracts with fuel suppliers. As a result, during cold winter days when demand for natural gas to use in heating is high, less natural gas is available for use by electrical generators. In the model, the natural gas available for electrical generation in any given hour is calculated as the total potential injections into the system from the interstate pipeline system and LNG terminal supplies less the demand for natural gas from LDCs:[30]

Natural Gas Available for Generators

≤ Interstate Pipeline Capacity + LNG Terminal Supply – Net LDC Gas Demand

Our gas availability analysis is based on natural gas pipeline capacity and LDC demand (by temperature) data and models provided by ISO-NE, and is consistent with the fuel security review of Forward Capacity Market de-list bids performed by ISO-NE for FCA 14 (the FCA 14 Fuel Security Review).[31] Pipeline capacity into ISO-NE is assumed to total 3.59 Bcf per day, which includes capacity for Algonquin, Iroquois, Tennessee, and Portland. This pipeline capacity takes into account capacity expansions expected to be completed by 2025 and subtracts gas under "pass-through" contracts that flow to Long Island. LDC demand by temperature is modeled using the ICF model from the FCA 14 Fuel Security Review. LDC demand increases, and gas available for electric generation drops, when the ISO-NE hub temperature falls.[32] Thus, based on the historic 2016/17 winter when temperatures were generally mild, more natural gas is available for electric generation in the Infrequent Case than in the Frequent Case, which uses the historic 2013/14 winter when winter temperatures tended to be lower.

In the Central Cases, we assume that the region's available LNG supply is consistent with (1) the estimated delivery capability of the Canaport LNG facility to New England, and (2) the exit of the Everett Marine Terminal LNG facility in Everett, MA (commonly referred to as Distrigas or DOMAC.[33] This assumption may either under- or overstate the likely supply of LNG under Central Case conditions. While potential supply from Canaport may not be fully contracted at present, the assumed exit of DOMAC would likely increase demand for natural gas from remaining sources of fuel supply.

Figure 12 shows the natural gas supply available to the electricity sector at various temperatures after accounting for these supplies and uses**.** This available supply reflects the difference between the maximum available natural gas supply, represented by the shaded area, and LDC gas demand, represented by the black line. As the temperature gets colder (moving to the right on the figure), the LDC natural gas demand increases, leaving a decreasing quantity of gas supply for the electric sector.

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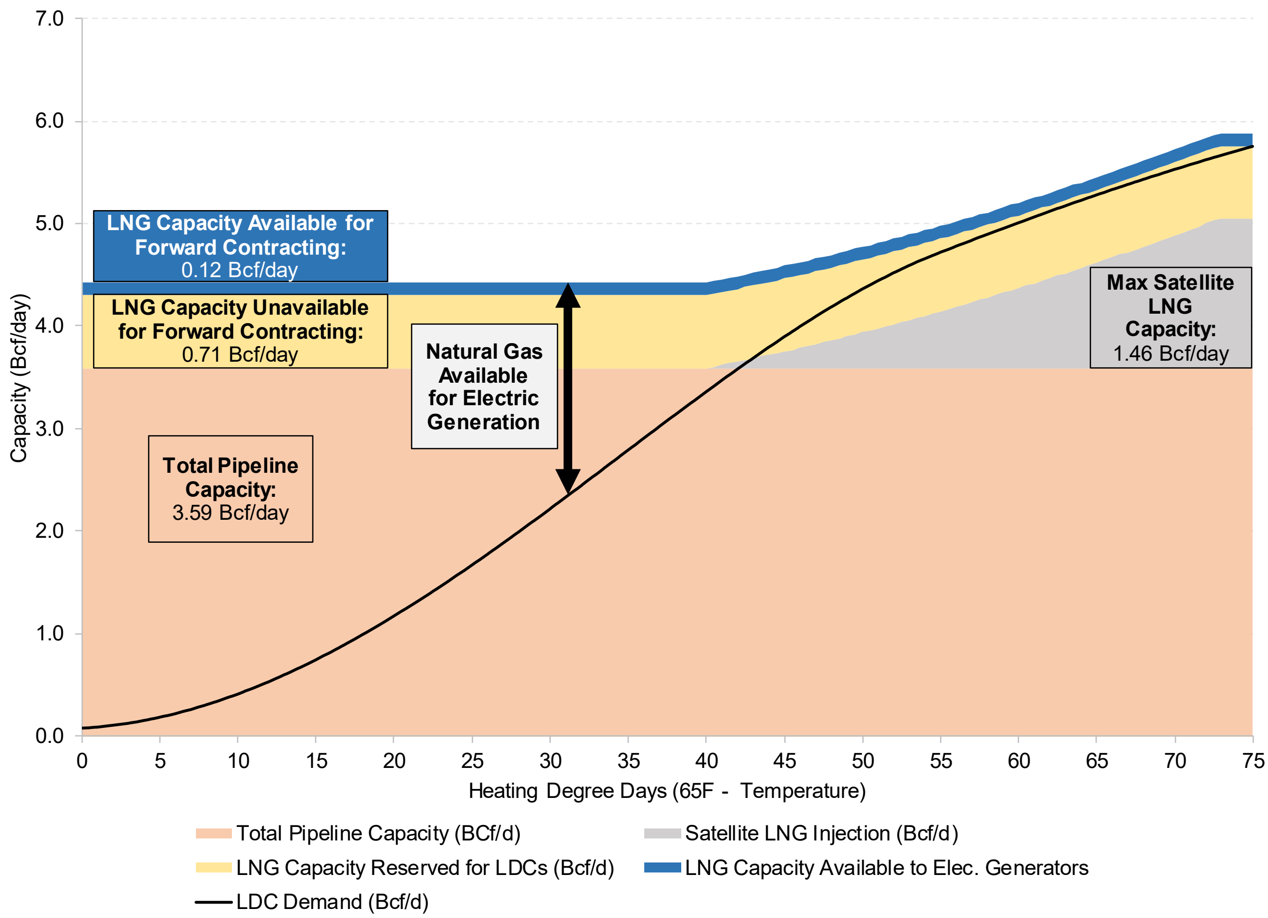
30 Natural gas available for generation is "shaped" across the hours of a day to allow for greater gas use during hours of peak electrical demand. No geographic constraints are modeled.

31 Sproehnle, Norman, "Forward Capacity Auction 14 (FCA 14): Fuel Security Review Inputs Development," March 29, 2019.

32 LDC demand for pipeline gas is also (partially) offset by injections of gas supply from satellite LNG facilities during periods of extreme cold when demand is highest. These satellite facilities are typically owned and operated by the LDCs.

33 Deliverable LNG supplies from Canaport are transported to New England via the Maritimes and Northeast Pipeline.

Figure 12. Natural Gas Supply and Demand by Heating Degree Day



In response to the increased incentives for delivery of energy in real-time created by ESI, we assume that certain gas-only generation units enter into forward contracts with an LNG terminal in the ESI cases. Under these forward contracts, the contract holder pays an up-front reservation charge in exchange for the right to purchase natural gas at an agreed-upon commodity price, assumed to be $10 per MMBtu, on 10 days over the course of the winter. These contracts do not increase the aggregate supply of natural gas available to the electricity sector, as we assume that the LNG terminals supply fuel to the market at their full transmittable capacity even if no such contracts are signed.[34] However, the forward LNG contracts may reduce the cost at which fuel is procured, and may lower the cost of power supply for resources with these contracts. To the extent that ESI would incent contracts with LNG terminals for supplies that would otherwise not be brought to the region, the Impact Assessment would tend to understate the reliability benefits of ESI.

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34 The structure of this contract does not have a material effect on outcomes of the Impact Assessment. The assumed commodity price ($10 per MMBtu) for the contract is most consistent with a call option contract, in which the contract holder has the right, but not the obligation, to take supplies. If a take-or-pay contract were assumed, the commodity cost would likely be lower, which could lower production costs during some hours, but would otherwise generally leave market outcomes unchanged.

Daily natural gas prices in each case are the unadjusted historical base year prices for Algonquin natural gas for the given day (where the historic day-ahead price is assumed for both day-ahead and real-time), and are used in conjunction with unit heat rates to determine fuel costs for natural gas and dual fuel units. Our natural gas market analysis does not attempt to calculate a general equilibrium natural gas price and quantity for each day. Such modeling is beyond the scope of our assignment, and would be particularly complex, given the region's unique natural gas demand and supply conditions.

2. Liquid Fuel Price, Storage, and Refill Assumptions

The energy supply that can be produced by oil-only and dual-fuel units running on oil is constrained by the amount of fuel oil that is in their storage tanks at the beginning of each hour. The model maintains an accounting of fuel in inventory (storage tanks) for each unit given its initial inventory, subsequent use to generate power, and replenishment of inventory ("refueling"). Inventory levels are updated for each operating day.

Each oil-only or dual-fuel unit starts the winter (or other modeling period) with an initial inventory that is drawn down if the unit generates electricity (using oil). If the inventory falls below a unit-specific "trigger quantity," then the unit receives a replenishment shipment of liquid fuel (equivalent to a number of tanker truck or fuel barge loads) after a specified order lead time. Unit replenishment behavior is assumed to differ across units based on the means of replenishment (tanker or barge), maximum tank size, and other characteristics. **Figure 13** shows an illustrative example of the fuel inventory of a specific resource on each day, and the various parameters that affect refueling over the course of the winter.

Figure 13. Illustrative Daily Fuel Inventory with Refueling Model Parameters

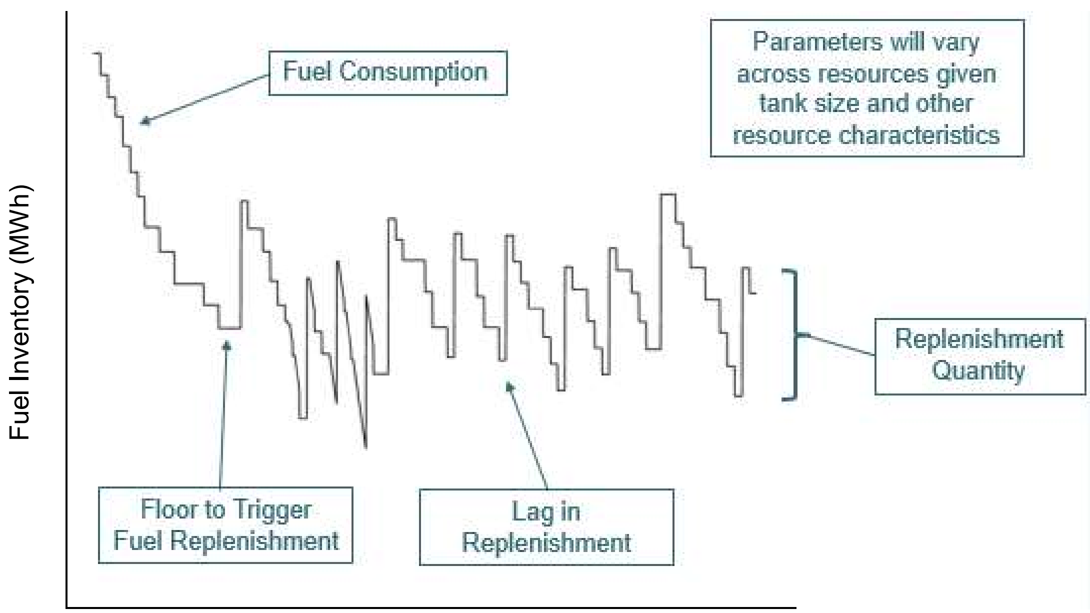


Table 6 summarizes the parameters used in each unit's refueling model. These parameter estimates are based on a combination of sources, including the ISO-NE fuel surveys, discussions with system operators and other New England market participants, and experience with fuel security analysis in other regions.

Table 6. Fuel Oil Resources, Initial Inventory and Refueling Model Parameters

Refuel Type		**Truck**			**Barge**
Size		**Small**	**Medium**	**Large**	
Unit Tank Storage Capacity (days)		(0 - 1]	(1 - 3]	(3 +)	(0 +)
Initial Fuel Inventory	CMR	December 2018 Inventory			
	ESI	CMR Fuel Levels + Incremental Inventory			
Rate of Fuel Delivery (gals per day)	CMR	123,750	123,750	123,750	375,000
	ESI	165,000	165,000	165,000	500,000
Last Refill Date		2/28/2026	2/28/2026	2/28/2026	2/14/2026
Order Lead Time (days)		1	1	1	4
Refill Threshold (percentage of initial inventory)		70%	40%	30%	10%

Note: Rates of fuel delivery are based on delivery capability and shipment quantity.

The maximum fuel oil storage capacity for oil and dual fuel units is based on historical unit-specific fuel survey data from ISO-NE. Units are assumed to enter the winter modeling period with a winter starting fuel quantity that is a fraction of their maximum fuel storage capacity, also based on historical fuel survey data.[35] Under CMR, each unit's starting inventory is based on its December 2018 inventory, when the Winter Fuel Program was not in effect.

The incentives created by the ESI proposal are expected to change these fuel inventory and refueling decisions. Under ESI, we assume the units start the winter with a larger initial inventory than in the CMR Case. Initial inventories under ESI are set using information on December inventory levels from years when ISO-NE's Winter Program was in effect (winters of 2014 to 2017). These programs compensated resources for increasing stored fuel supplies, with compensation mechanisms differing across the years the programs were in effect. Thus, the initial inventories held during these winters reflect the market's response to the incentives created by the earlier winter programs, and are a reasonable starting point for an expected response to ESI.

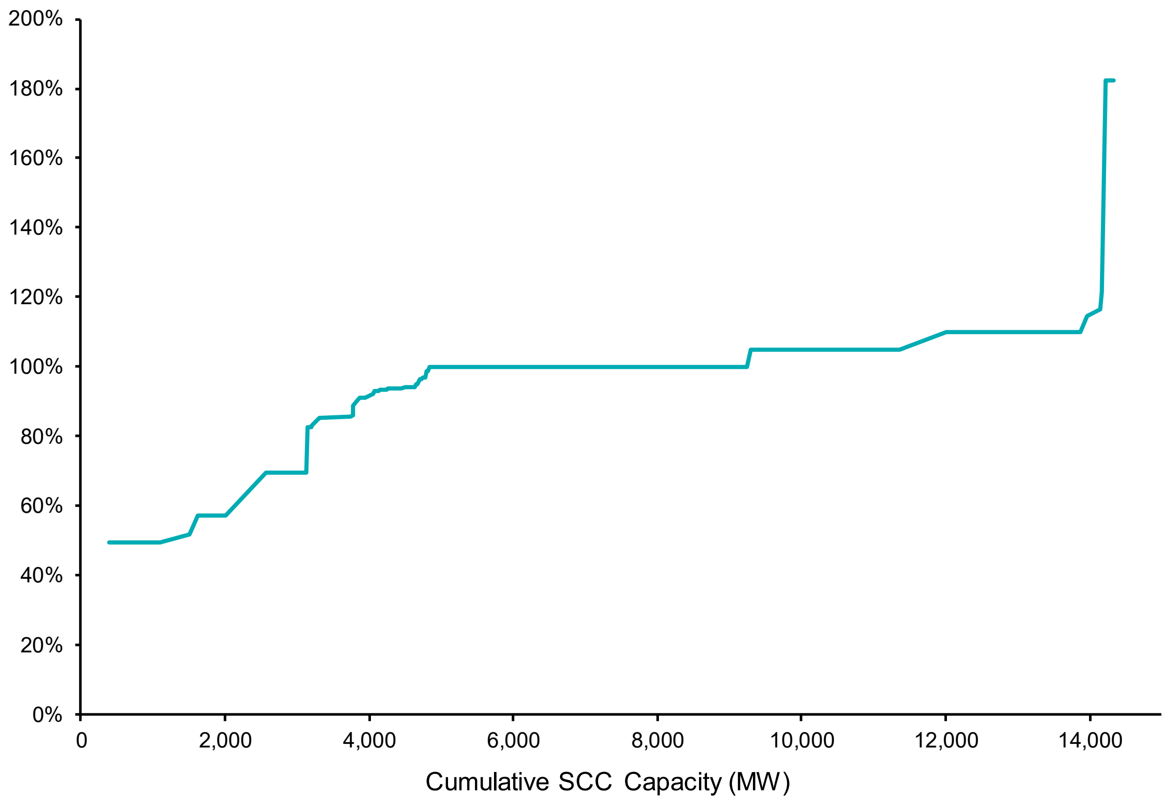
Using the average December inventory as a starting point for calculating assumed initial fuel inventories under ESI, we make subsequent adjustments (above or below the 2014-17 Winter Program levels) to account for a number of factors. In particular: units with low marginal generation costs are assumed to hold more fuel (relative to other units), as these resources are more competitive at supplying DA energy and DA energy options; certain units with very large storage tanks (relative to capacity) are assumed to hold less fuel than was held during the Winter Program periods, as less market benefit was observed from incremental inventory; and some units with small tanks (relative to capacity) are assumed to hold more fuel, when historical December inventories were relatively low. In **Section IV.1**, we evaluate whether the assumption about this increase in starting inventories appears to be consistent with the incremental incentives to maintain energy inventories that ESI creates. **Figure 14** illustrates this variation in initial inventory, showing the distribution of the ratio of

[35] Units with storage enter the modeling period with as much liquid fuel as they held during winters of 2016/17 and 2017/18, when the ISO-NE Winter Fuel Program was in effect.

(1) assumed initial inventory under ESI to (2) the average Winter Program initial inventories (December 2014 to 2017) across the set of resources in the analysis that can hold fuel oil in the analysis.

Figure 14. Initial Fuel Oil Inventory under ESI

Assumed Initial ESI Inventory Relative to 2014-17 Average December Storage



Within the model, fuel inventories start at the initial level and are reduced as the resource consumes fuel to supply electricity in real-time. Fuel inventories are drawn down until fuel stock declines below a unit-specific refueling threshold that is set as a fixed fraction of initial inventory. When inventories fall below this threshold, refueling occurs. Both the refueling threshold and the refill rate – i.e., the quantity of liquid fuel (per day) – depend on how the resource is refueled (tanker or barge) and the size of the unit's fuel tank. For example, as illustrated in **Table 6**, units that refuel by barge will refuel less frequently but with a larger quantity per refill compared to units that refuel by truck. In all cases, units will never refuel to a level greater than their initial inventory.

Along with the changes to initial inventory levels discussed above, we also assume changes to the refueling strategies used by market participants in response to ESI's incentives for increased energy inventories. In particular, we assume that under ESI, fuel-oil resources refuel at a faster rate (i.e., more fuel per day), one-third higher than in the CMR case. This assumption is designed to reflect the potential responses of market participants to the incentives created by ESI.[36]

Assumed fuel oil prices are the unadjusted monthly Chicago Mercantile Exchange futures contract prices as of August 2019 for delivery months as far into the future as possible. If a unit is modeled to run on liquid fuel in a given hour, fuel costs are based on fuel replacement cost at the time it is burned, not the original purchase price of the fuel.

D. Market Settlement & Model Outputs

The model determines production of electricity in each hour, day-ahead and real-time energy and ancillary service prices, quantities of day-ahead and real-time products supplied by each resource, and various resource- and system-level variables related to energy inventory and aggregate fuel use. These outputs are used to develop summary metrics for each case and scenario, including market price and payment impacts, energy mix, and fuel system operational metrics. These outcomes reflect the two-part settlement process used in the New England markets. ESI's impacts on outcomes are then calculated by taking differences in outputs between CMR and ESI cases.

1. Market Price Impacts

Hourly market clearing prices (e.g., LMPs in the energy market) are simulated for the day-ahead and real-time markets. Differences between DA and RT LMPs reflect many potential factors, including: incremental energy inventory procured under ESI that is used to meet DA and RT energy demand; substitution in resource-level awards under ESI between energy and DA energy options; and/or changes in opportunity costs given fluctuations in resource-level energy inventory.

Hourly clearing prices for energy market products are set using the same approach as the current (and proposed) market algorithms. For DA energy, RT energy, RT operating reserves, and ESI products (where appropriate), clearing prices are set at the respective shadow price for the relevant product constraint. The shadow price measures the cost to the system of obtaining an additional MWh of the given product. In cases where an incremental MWh of a product can be procured from the marginal resource, the shadow price is the same as the product offer price from that resource. In instances when the incremental MWh is met by substitution of product awards between resources, the shadow price will reflect the increase in total costs associated with these changes in supply.[37] Examples of this market clearing logic can be found in various ISO-NE presentations.[38]

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[36] The assumed change in refueling rate is consistent with the range of different daily refueling rates observed among resources currently within the market.

[37] Since resources do not provide offers for RT operating reserves, shadow prices for these products are set based on the total change in costs associated with the redistribution of resource product awards, rather than a RT operating reserve offer from a marginal resource. This approach is consistent with how RT operating reserves prices are established in New England today.

[38] ISO NE, "Winter Energy Security Improvements: Market-Based Approaches", May, June, and July 2019.

2. Customer Payments

Customer payments are estimates for each case, reflecting (1) net payments for energy to suppliers, including day-ahead payments and settlement of real-time deviations; (2) FER payments associated with the sale of DA energy; and (3) the payments for ESI products, including the day-ahead purchase of energy options and the settlement of these DA energy options against RT LMPs. The model does not consider any changes in payments to other ISO-NE-administered wholesale markets such as the FCM or the FRM. Changes in payments reflect several factors, including the changes in energy supply due to the effect of ESI incentives on energy inventories, substitution among resource-level awards that shifts the mix of resources supplying energy, and the procurement of additional services in the day-ahead market that may improve system reliability.

Day-Ahead and Real-Time energy payments are calculated based on the sum of all cleared day-ahead positions (DA LMP * quantity), minus any deviations in real-time position at the RT LMP. This cost component is calculated in the same fashion under both the CMR and ESI model runs.

FER payments are not part of current market rules, but are made to resources supplying energy when their energy supply contributes to meeting the FER under ESI. This occurs when there is a positive EIR or when the EIR is exactly zero, in which case the FER constraint is binding and (all else equal) there is a positive cost to the system to serve an incremental 1 MWh higher load forecast (as described in **Section III.B.5**). The total FER payment is the EIR price times the quantity of DA energy awards.

Net ESI product payments reflects two components. The first component is the payment to generators for supplying DA energy options to meet ESI product demand. This payment is equal to the market-clearing price of the DA energy option for each ESI product times the quantity of this product procured.

The second component accounts for settlement of the DA energy options against the RT LMP. Load is paid the option closeout cost by DA energy option suppliers, which is therefore represented as a credit to load. The option closeout cost is RT LMP minus the strike price if the RT LMP is greater than the strike price, while the closeout cost is zero if the RT LMP is less than the strike price. Closeout costs are estimated by settling historical RT LMPs against the strike price.[39] The net cost of the ESI products thus reflects these upfront option payments net of real-time closeout costs.

3. Changes in Production Costs and Energy Mix

The model analyzes changes in production outcomes, including production costs and clearing resource mix. Production costs include both modelled variable production costs (including fuel, variable operations and

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[39] We calculate energy option prices and settlement using the same underlying historical distribution of prices. There are several reasons for employing this methodology. In theory, output from our production cost model could be used to calculate energy option prices and settlements. However, there are several concerns with an approach that uses modeled output to determine these prices. First, production cost models generally understate market volatility (and therefore may estimate energy option prices and settlements below their expected values), unless calibrated to capture such volatility, which our model is not. Second, because energy option offers are an *input* to our model, we cannot rely on an *output* of the model, RT LMPs, to calculate them. More importantly, when estimating prices and settlement of financial options, the larger time-series available through historical data will provide a more reliable approach than reliance on a smaller sample of real-time prices from our production cost model. And, settling an option priced using historical data with prices from a different mathematical framework (i.e., our production cost model) would create an internal inconsistency, making the prices invalid and causing the resulting settlement to have excess (or insufficient) returns.

maintenance, and emissions) and fixed costs of production. Fixed costs of production represent changes in costs associated with taking action to secure fuel incentivized by the proposed ESI rules. These fixed costs include the holding costs associated with larger end-of-winter fuel inventories and upfront LNG forward contract costs.

4. Operational and Reliability Metrics

The production cost model is designed to simulate the market clearing in the New England day-ahead and real-time energy and ancillary services markets. Thus, its primary function is to assess market outcomes, illustrating differences between current market rules and those under the ESI proposal. However, due to the design of our model and the deterministic scenario approach we take, our assessment is not designed to provide a thorough or complete analysis of reliability outcomes and may not fully capture the likelihood that extreme reliability events may occur, or the extent to which ESI would reduce the likelihood that they occur. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability outcomes, especially during stressed conditions. The model does not account for the full range of contingency events that can affect resource, transmission and fuel availability, where the contingencies for which we do account reflect average, not probabilistic, effects (e.g., using average forced outage rates rather than probabilistically sampled outage rates). Using these averages may not fully consider the heightened risks posed by such contingencies during acute periods of system stress due to constraints on fuel supplies. Our analysis also does not account for transmission topology, which can capture the locational limits and constraints that can lead to reliability concerns in particular zones or load pockets.

Furthermore, our model does not include plant commitment and dispatch and other intertemporal limits to plant operations (e.g., minimum run times and minimum down times). As a result, our model assumes smoother and more continuous plant operations than occurs under actual system operations. Finally, the model seeks to evaluate the expected market impacts of ESI and assumes a market response to stressed conditions, such as additional fuel procurements and improved fuel supply chain logistics, especially under the ESI Scenarios where the incentives to make such procurements are increased because of the additional revenue associated with the new ancillary services.

Due to the combined impact of these factors, our model may not fully capture extreme reliability events associated with any market simulation under both CMR and ESI, including the potential for reserve shortages. To the extent that ESI would increase resource incentives to be available in real-time, the analysis may therefore underestimate potential reliability benefits of the ESI proposal. Despite these limitations, we analyze several metrics related to fuel systems operations that potentially provide information related to reliability outcomes. Along with operating reserve shortages, we also measure several outcomes related to the use of the natural gas supply system and fleet-wide fuel oil inventory that seek to illustrate if ESI appears likely to increase the quantity of fuel available for electric generation, especially during stressed conditions.

IV. Impact of Energy Security Improvements on the Energy Market

The proposed ESI market rule changes would create new day-ahead ancillary services that are expected to improve both efficiency and reliability by addressing gaps in the current market. In this section of the report, we summarize the results of our assessment of the impact of the ESI proposal on the ISO-NE energy markets. Our assessment includes both quantitative estimates of impacts based on the production cost model and qualitative analysis developed through economic and market analysis. The analysis quantifies the expected impacts for particular deterministic scenarios reflecting assumptions about market and system conditions. It also illustrates the mechanisms through which ESI will impact market outcomes.

Below, we summarize our analyses' key findings regarding ESI's expected impact on market outcomes:

1. Consistent with its design, ESI would create additional incentives for resources to maintain secure energy supplies (e.g., higher levels of energy inventories). These incentives are created through two new revenue streams: FER payments for resources supplying DA energy, and revenues to compensate resources that supply the new ESI products. **Section IV.1** discusses these incremental sources of revenue, and analyzes the incremental incentives to support energy inventory.
2. ESI would provide price signals to procure the new day-ahead ancillary services. Procurement of DA energy and these new ancillary services is co-optimized, ensuring that services are procured at least cost and that price signals are consistent with the costs associated with providing this service. Our analysis reflects the gains from this co-optimization and the resulting allocation of products to different resources, given substitution possibilities and the relative cost of supplying DA energy and DA energy options. S**ection IV.1** discusses the estimated ESI prices in each Case, while **Section IV.2** discusses the mix of resources supplying ESI products.
3. ESI would better preserve energy inventory compared to current market rules. With ESI, resources can sell DA energy options and thus be compensated for maintaining energy supply in reserve, rather than using limited inventories to supply energy, which is the only source of compensation under current market rules. S**ection IV.2** discusses expected shifts in the mix of energy supplies under ESI.
4. Under ESI, the day-ahead market would be less likely to clear energy supplies that are less than the forecasted load, as compared to current market rules. And, any remaining gap between cleared supplies and forecast load will tend to be smaller with ESI. This outcome is a consequence of the auction clearing mechanism under ESI, which, as described in **Section III.B.5**, balances losses from procuring additional DA energy with cost savings from reducing the EIR quantity. **Section IV.2** shows how these shifts in DA energy supply are expected to occur under ESI.
5. ESI would be expected to increase efficiency and lower production costs, particularly under stressed market conditions when the increase in energy inventory reduces electricity production from higher cost fuels. S**ection IV.3** further discusses these changes in efficient and provides estimated production cost changes for each Case.

The ESI proposal will also have consequences for the flow of payments by load (and net revenue to resource owners) in the ISO-NE energy markets:

A. Aggregate payments by load to suppliers would be affected by ESI, although these impacts vary with market conditions. When stressed conditions are uncommon (e.g., the Infrequent Case), ESI would likely increase payments to generators from loads.

B. However, with stressed conditions, impacts would depend on two factors that affect payments in different directions. On the one hand, payments would increase for ESI ancillary services (including the FER). On the other hand, payments would decrease due to the availability of additional energy inventory supplies during tight market conditions, thus partially, fully or more than fully offsetting the cost of the ESI services. The net change in payments under stressed conditions would depend on a combination of factors, such as the nature of the stressed conditions (e.g., frequency of stressed conditions and duration of these conditions) and the market's response to ESI incentives. **Table 7** summarizes this change in payments for the three winter Central Cases.

Table 7. Summary of Change in Total Payments, Winter Central Case

		Frequent Case				Extended Case				Infrequent Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy & RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary Services	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

C. Changes in net revenues vary across resource types, although direction of these impacts (i.e., whether net revenues increase or decrease) is generally the same across resource types within each Case (i.e., given the nature of the stressed market conditions).

D. Estimated impacts reflect only energy and ancillary services market outcomes, and do not consider any changes in payments (and net revenues) associated with FCM or FRM that could potentially occur.

The following sections detail these results, evaluating price and incentive effects, the supply of DA energy and ESI products, production costs, total payments, net revenues, and operational outcomes. We first discuss the winter Cases, and then discuss the non-winter Cases. Unless otherwise stated, differences or changes in outcomes discussed in the sections that follow refer to differences between the ESI and CMR results for the relevant case.

A. Winter Cases

1. Prices and Incentives for Energy Supply

The ESI proposal would have a number of dynamic effects on day-ahead market clearing prices. Along with introducing new ancillary service products, LMPs for DA energy will be affected by the new interactions among day-ahead products under the proposed design. The resulting price signals would create incentives for resource owners to efficiently supply services to the region, particularly the reliable delivery of energy supply in real-time. Thus, in this section, we consider these price impacts and their effects on incentives in tandem.

In principle, improvements in the reliable supply of real-time energy can be made through many actions. Our quantitative analysis considers improvements in energy inventory, including increasing the quantity of liquid fuel held in on-site storage tanks and contracting for more-firm delivery of fuel, such as through a forward contract with an LNG terminal. In practice, we expect that these changes reflect a subset of the actions market participants would take to improve their ability to deliver energy in real-time. More specifically, ESI's incentives would likely affect many other types of actions that would have consequences for resources' ability to supply energy in real-time, such as preservation of limited energy inventories (e.g., at hydropower facilities),[40] investment that expands potential fuel storage (e.g., retrofitting gas-only plants for dual-fuel), general improvements in operational performance (e.g., other contractual arrangements for fuel, reducing forced outage rates), and the internalization of the potential ESI revenues (and costs) in entry and exit decisions.

For each of these decisions, resource owners go through a process of balancing various tradeoffs that have implications for the reliability of energy supply in real-time. For example, owners of resources with stored fuel supplies would balance the costs of investing in additional energy inventory against the benefits of this additional investment, in terms of increased market returns. When making this assessment, ESI would increase generator incentives to secure energy inventory relative to current market rules through two new sources of return.

- ***FER payments***. FER payments would provide incremental revenues to resources supplying DA energy. Thus, as resource owners consider the costs and benefits to holding additional fuel inventory (at the margin), FER payments would increase the return to holding additional inventory compared to current market rules, causing them to increase their inventory relative to current market rules. These decisions to hold additional inventory would manifest themselves in an increase in DA energy supply when the supply a resource might otherwise offer would be limited by its fuel inventory. Such increases in supply are most likely to occur during stressed market conditions, when fuel supplies are most limited and the economic gains (increased revenues) and reliability benefits from holding fuel supply are greatest.
- ***ESI products.*** By providing a new means to be compensated for the reliability benefits provided by energy inventory, the sale of DA energy options to satisfy ESI product requirements provides a means

[40] While the model allows fossil fuel resources with limited inventories to preserve their fuel via opportunity cost bidding, for 'profiled' limited energy resources, such as pump storage facilities, the model assumes that their energy production is constant between CMR and ESI. This methodology is discussed in more detail in **Section II.B.3**.

for resources with energy inventory (e.g., fuel supplies) to earn a return on this inventory, even if it is not consumed. Thus, at the margin, holding more fuel supply than resources would under current market rules provides additional revenue streams through the sale of DA energy options.

Along with providing the capability to support a DA energy option through the delivery of real-time energy, energy inventory can lower a resource's financial risk from selling a DA energy option. Thus, a resource with energy inventory can submit a more competitive offer for a DA energy option, making it more likely to receive an award. In turn, the financial risk, and as a result, the financial cost, may be reduced when taking a DA energy option award, providing a greater return to the energy option award.

The quantitative analysis in **Section IV.1.c)** and **Section IV.1.d)** illustrate the benefits of additional revenue streams created by ESI to support incremental energy inventory.

a) Payments to DA Energy Supply

Under ESI, the change in payments to resources that supply DA energy will reflect the net impact of several different factors. These effects derive from different aspects of the ESI design, with some increasing payments to DA energy and others decreasing payments. Our quantitative analysis captures the net impact of these different effects, which in aggregate may lead to either a positive or negative impact on payments to DA energy.

First, under ESI, resources awarded DA energy positions earn FER payments, in addition to the LMP, which will tend to increase compensation for DA energy provided. FER payments are incremental payments made to compensate generation that sells energy in the day-ahead market for helping to meet the FER requirement. These payments compensate resources that supply DA energy for their contribution to meeting the FER requirement, and ensure that resources supplying energy are no worse off for selling DA energy rather than a DA energy option (i.e., the awards are incentive compatible).

Second, ***with the FER constraint, the market will clear a larger quantity of DA energy under ESI compared to current market rules, although this effect would not be expected to meaningfully change DA LMPs***. As described in **Section III.B.5**, the total quantity of DA cleared energy will tend to increase under ESI. Our quantitative estimates of this impact are provided in **Section IV.2**. However, because ESI does not directly change RT LMPs, we would not expect this effect to produce any change in DA LMPs, assuming market participants would trade (arbitrage) on any predictable and meaningful difference between DA LMPs and RT LMPs until such differences are eliminated.[41] **Section III.B.5** describes these interactions in greater detail.

Third, co-optimization of all products in the day-ahead market can also lead to substitutions among products that can affect market clearing for DA energy. Because the optimization under ESI satisfies constraints for multiple DA products, the positions for each service awarded to a given resource will depend, among other things, on the relative offer prices from that resource for each of the services. The result is that

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41 While we would not expect DA LMPs to change from the combined effect of the FER constraint and increase in demand in response to that constraint, DA LMPs would be expected to change due to increase in energy supply in response to the incentives created by ESI, an effect that is described below.

the lowest cost offers for DA energy may not always be awarded a DA energy position. For example, a more-costly DA energy offer may clear over a lower-cost DA energy offer if the resource with the lower-cost offer creates more cost savings (social surplus increases) by supplying a DA energy option rather than DA energy.[42] In addition, given differences in energy inventories and different substitution possibilities, opportunity costs for energy limited resources (in both day-ahead and real-time) will differ between the ESI and CMR cases.

Each of these impacts is driven by changes to market-clearing with the addition of the new ancillary services. But, we also expect ESI's incentives to lead to an increase in energy inventory, which will have implications for payments to energy.

Fourth, an increase in energy inventory under ESI* would be expected to *reduce* LMPs, all else equal, *which will tend to reduce compensation for DA energy provided. In effect, ESI would increase energy supply, which can lower LMPs during tight market conditions when the market would otherwise rely on higher-cost resources. This indirect effect, the reduction in LMPs, would be expected to reduce any increases in compensation for DA energy discussed by the first factor above, and will dampen the direct effect of ESI's incentives. Such "equilibrium" adjustments by the market to new incentives occur with any change in policy or regulation.

Table 8 provides the change in payments to energy for the three Central Cases in ESI compared to CMR. Changes reflect both the change in LMPs and the additional FER payments. Across all three winter Central Cases, DA LMPs are reduced by $1.20 per MWh (Infrequent Case) to $6.43 per MWh (Extended Case). These LMP changes are the result of the combination of factors identified above, although the most important factor is the incremental energy inventory that the model assumes under ESI (i.e., the fourth factor identified above).

In the Infrequent Case, after including the FER payments, total payments to DA energy (i.e., the change in the DA LMP plus FER payments) increase by $0.74 per MWh. Without any periods of system stress, the additional supply of energy inventory incented by ESI has a smaller downward effect on LMPs. Consequently, compensation to energy supply for its contribution to meeting the FER leads to an increase in net payments to DA energy.

In the two Cases with stressed conditions, we find different impacts: in the Frequent Case, average net payments to DA energy increase by $2.27 per MWh, whereas, in the Extended Case, average net payments decrease by $2.88 per MWh. In both of these cases, additional energy supply incented by ESI has a downward effect on LMPs. In the Frequent Case, as in the Infrequent Case, the payments for FER outweigh the reductions in LMPs. In the Extended Case, however, this downward LMP effect outweighs the cost of compensating for contributions to meeting the FER, resulting in a net reduction in payments per MWh.

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[42] For example, assume Resource A offers DA energy at $50 per MWh and a DA energy option at $12 per MWh, while Resource B offers DA energy at $45 per MWh and a DA energy option at $5 per MWh. Under current market rules, Resource B would supply DA energy before Resource A due to its lower offer. Under ESI, if the system requires one resource to provide DA energy and the other DA energy options, the optimization would award Resource A energy and Resource B energy options because the total cost of doing so ($55 = $50 for A's energy plus $5 for B's option) is less than the alternate scenario where lower cost B supplies energy ($57 = $45 for B's energy plus $12 for A's option).

Table 8. Average DA Payments to Generators, Winter Central Case
CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
	Day-Ahead LMP	Day-Ahead LMP	FER	Day-Ahead LMP+ FER	Real-Time LMP	Day-Ahead LMP	Day-Ahead LMP + FER
Case	[A]	[B]	[C]	[D]=[B]+[C]	[E]	[B]-[A]	[D]-[A]
Frequent Case	$127.40	$121.91	$7.76	$129.67	$121.60	($5.49)	$2.27
Extended Case	$85.15	$78.72	$3.55	$82.27	$79.73	($6.43)	($2.88)
Infrequent Case	$54.97	$53.77	$1.94	$55.71	$55.86	($1.20)	$0.74

b) Prices for ESI Ancillary Services

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 9** reports average award prices for these products for the Central Cases. These prices are weighted averages, reflecting the quantity of each product procured in each hour. These quantities are assumed to be the same in all hours for GCR10, GCR30 and RER, although in actuality these quantities may differ from hour to hour to reflect changes to the potential size of system contingencies and other factors. By contrast, the quantity of EIR procured in each hour is dynamically determined by the model (given tradeoffs from substitution of DA energy for EIR), varies from hour to hour, and is zero in a large fraction of hours because the substitution between products leads the day-ahead optimization to procure enough energy to meet the forecast load.

Table 9. Weighted Average DA Energy Option Clearing Prices, Winter Central Case
($ per MWh)

	($/MWh)			
Case	EIR/FER	GCR10	GCR30	RER
Frequent Case	$69.11	$27.03	$27.03	$24.91
Extended Case	$47.74	$14.51	$14.45	$13.49
Infrequent Case	$8.36	$5.77	$5.75	$5.75

Average prices for GCR10, GCR30 and RER vary due to differences in resources' ability to supply each product. Procuring 'higher quality' ESI products (e.g. GCR10) may require accepting higher-priced offers from resources that can provide these services, which would increase their market-clearing price relative to the clearing price for 'lower quality' products. For example, because fewer resources are able to receive a GCR10 award, as compared to the other DA energy options, these prices are higher, reflecting the need to accept higher priced offers to meet the GCR10 requirement in some hours.

Prices vary across Cases, driven by several factors. First, the quantity of DA supply (energy and energy options) differs across cases, with the largest quantities in the Frequent Case and the smallest quantity in the Infrequent Case. When a larger DA supply is needed, prices will be higher, all else equal, because the market clears at a higher point on the DA energy and DA energy option supply curves. At the extreme, DA energy option product shortages may occur, when their prices are set by the penalty factor values. Thus, Cases with higher DA energy option product prices are due, in part, to a larger number of RER shortages. Second, expected closeout costs are highest when price volatility is greatest, though in such cases, the higher option price may be offset by larger expected closeout costs. Thus, the option prices are greatest in the Frequent

Case, which experience more hours with high levels of price volatility than in the winters in which volatile market conditions are less frequent.

Average EIR prices differ from the other ESI products because the quantity of EIR procured varies from hour to hour, and because EIR prices tend to be greatest in hours in which the EIR quantity is largest (i.e., EIR prices and quantities are positively correlated). **Table 10** provides further detail on the different outcomes for EIR/FER prices. The EIR/FER price is greater than zero whenever the FER constraint is binding. But, this constraint can bind when the EIR quantity is greater than zero and when it is *exactly* equal to zero (represented as "> 0" and "= 0" in the **Table 10**). The latter case occurs when the auction mechanism substitutes DA energy for EIR until EIR is exactly equal to zero, but the constraint continues to bind because increasing the load forecast would cause an immediate gap between cleared energy and the load forecast. In such cases, the price (i.e., "shadow price") associated with this constraint is positive and DA energy is compensated for keeping the EIR at zero. That is, decreasing DA energy would cause EIR to be positive, thus imposing a cost to procure energy options.

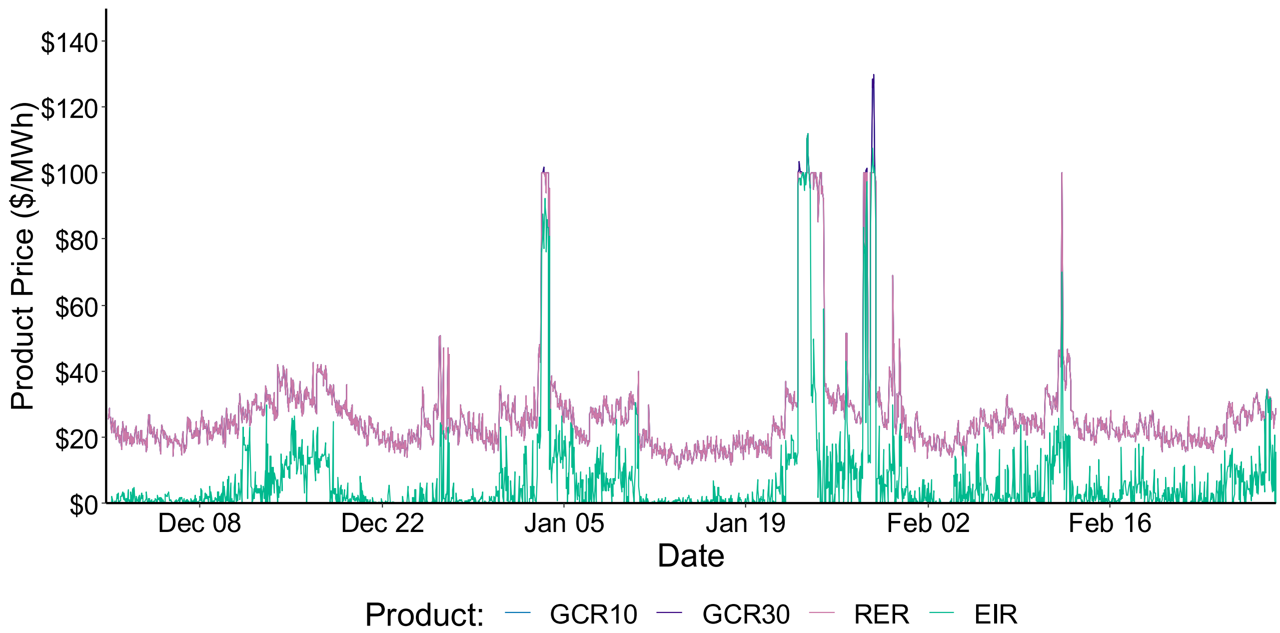
After accounting for adjustments to the EIR due to substitutions of DA energy for EIR, there is a positive quantity of EIR in a relatively small share of hours, ranging from 3% in the Frequent Case to 16% in the Infrequent Case. Hours when EIR is exactly zero, but the EIR price is positive, represents a large fraction of hours, ranging from 42% in the Extended Case to 72% in the Frequent Case. Hours in which cleared energy is greater than the forecast accounts for the remaining hours – 24% in the Frequent Case to 51% in the Extended Case.

Table 10. Frequency of EIR Quantity-Price Outcomes by Winter Central Case

ISO Forecast Load minus Cleared Energy Supply	EIR Quantity	EIR/FER Price	Frequent Case	Extended Case	Infrequent Case
> 0	> 0	> 0	3%	7%	16%
= 0	= 0	> 0	72%	42%	45%
< 0	= 0	= 0	24%	51%	39%

The average prices in **Table 9** mask hourly variation in prices within Cases. **Figure 15** illustrates this hourly variation for the Frequent Case, where it graphs prices for each of the four DA energy options. As we describe below, this hourly variation is an important element of the ESI proposal, as it signals periods of greatest need for energy inventory and compensates resources able to provide supply during these periods.

Figure 15. Estimated ESI Product Prices by Hour, Winter Central Frequent Case



c) Incentives for Investment in Incremental Fuel Oil

Under current market rules, oil-only and dual fuel generators have an incentive to hold fuel inventory so that they can earn revenues by converting this fuel into electricity and be compensated at the DA or RT LMP. Generally, we would expect these units to add fuel oil to their tanks up until the expected net revenues from additional fuel oil is outweighed by its expected incremental costs.

This same cost/benefit logic will continue to hold under ESI. However, ***ESI would increase the revenue streams earned from holding oil, thus incenting these resources to increase the quantity of fuel oil held in inventory relative to current market rules.*** More precisely, holding fuel inventory incurs additional costs given the risk that such inventory will need to be held for an extended period of time. This risk is relevant in New England, where in recent years, market prices have rarely supported power generation by fuel oil outside the winter months. On the other hand, additional fuel inventory may increase the resource's ability to supply energy and reduce its costs (and risks) of taking day-ahead positions. At present, these benefits are driven by the opportunity to earn margins (revenues in excess of costs) for selling power. With ESI, these margins would be increased by the FER payments associated with the sale of DA energy, and additional net returns earned through the sale of DA energy options.

Below, we analyze – through two different, but related avenues – the incentives for resources to make investment to improve their ability to deliver energy in real-time. First, we analyze the change in total returns from holding fuel oil under ESI, showing that these new revenues are large, particularly relative to the change in costs from holding additional fuel. Second, we analyze the price signals driving these incentives at the margin, particularly during stressed market conditions.

i. Change in Total Returns to Holding Fuel Oil under ESI

Table 11 to **Table 13** compare the new ESI revenues to the change in inventory costs for the quantity of incremental fuel ESI is assumed to incent.[43] New ESI revenue streams include FER payments and DA energy options. In these calculations, the DA energy option revenues reflect only the risk premium component of the marginal offer that sets the clearing price, but not the remainder, which corresponds to the closeout cost that the generator expects to pay back (on average) to load in the second part of the option settlement. The tables also show the change in economic costs of incremental energy inventory, measured by the financial ("holding") costs of having more fuel in inventory at the end of the winter because of decisions to increase inventory during the winter.

The tables demonstrate that the average incremental payments to resources under ESI generally far outweigh the additional holding costs. These results are indicative of the incremental returns to holding greater fuel oil due to ESI, and one illustration of the strong incentives created by the ESI proposal.[44] In the Frequent or Extended Cases, these ESI revenues far exceed the change in holding costs for all fuel-oil resource categories evaluated. For example, for Dual Fuel, Combined Cycle Units in the Frequent Case, the incremental cost of holding a larger quantity of fuel at the end of the winter because of more aggressive refueling under ESI is $14 per MW of capacity. By contrast, the additional revenues earned because of ESI compared to current market rules are $5,591 per MW of capacity ($5,452 and $139 per MW for FER payments and DA energy options, respectively), for a net increase in revenue of $5,577 per MW ($5,591 per MW in incremental revenues less $14 per MW in incremental costs).

In the Infrequent Case, where conditions are generally mild and the total quantity of oil burned is modest, the net change in revenues is lower for all technology types, and even negative for the oil-only, steam resources. However, while oil-only, steam resources incur losses in this Case, they still incur positive gains that are larger in magnitude in the winters with more frequent stressed conditions (i.e., the Frequent and Extended Cases). Thus, the precise quantity of incremental fuel inventory incented by ESI may differ from that assumed by our analysis, and may depend on a combination of factors, including resource owners' expectations about future winter market and weather conditions.

These results demonstrate that the additional revenues in the market from ESI far exceed the change in costs of holding additional fuel, and provide one illustration of the incentives ESI creates for oil resources to increase the quantity of fuel held during the winter. This incremental oil will improve the region's energy security and help maintain system reliability during periods of system stress.

[43] Incremental fuel quantities under ESI are discussed in **Section III.C.2**.

[44] As discussed above, as market participants determine the financially optimal quantity of fuel to hold, the new ESI revenues will increase the returns to holding more, rather than less, fuel in inventory, because the revenue earned from holding that fuel in inventory is greater than it otherwise would be under current market rules, thus offsetting the cost of holding additional fuel.

Table 11. New ESI Revenues and Change in Holding Costs, Winter Central Frequent Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$14	$5,452	$139	$5,577
Dual Fuel, CT	14	-$118	$5,875	$2,172	$7,929
Oil Only, CT	70	-$134	$1,784	$5,735	$7,385
Oil Only, Steam	13	-$1,257	$6,207	$583	$5,532

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 12. New ESI Revenues and Change in Holding Costs, Winter Central Extended Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$112	$2,113	$61	$2,063
Dual Fuel, CT	14	-$124	$1,760	$1,199	$2,835
Oil Only, CT	70	-$88	$654	$2,032	$2,598
Oil Only, Steam	13	-$1,291	$2,646	$98	$1,453

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 13. New ESI Revenues and Change in Holding Costs, Winter Central Infrequent Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$254	$785	$12	$543
Dual Fuel, CT	14	-$435	$150	$444	$159
Oil Only, CT	70	-$84	$7	$720	$643
Oil Only, Steam	13	-$1,315	$94	$3	-$1,218

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

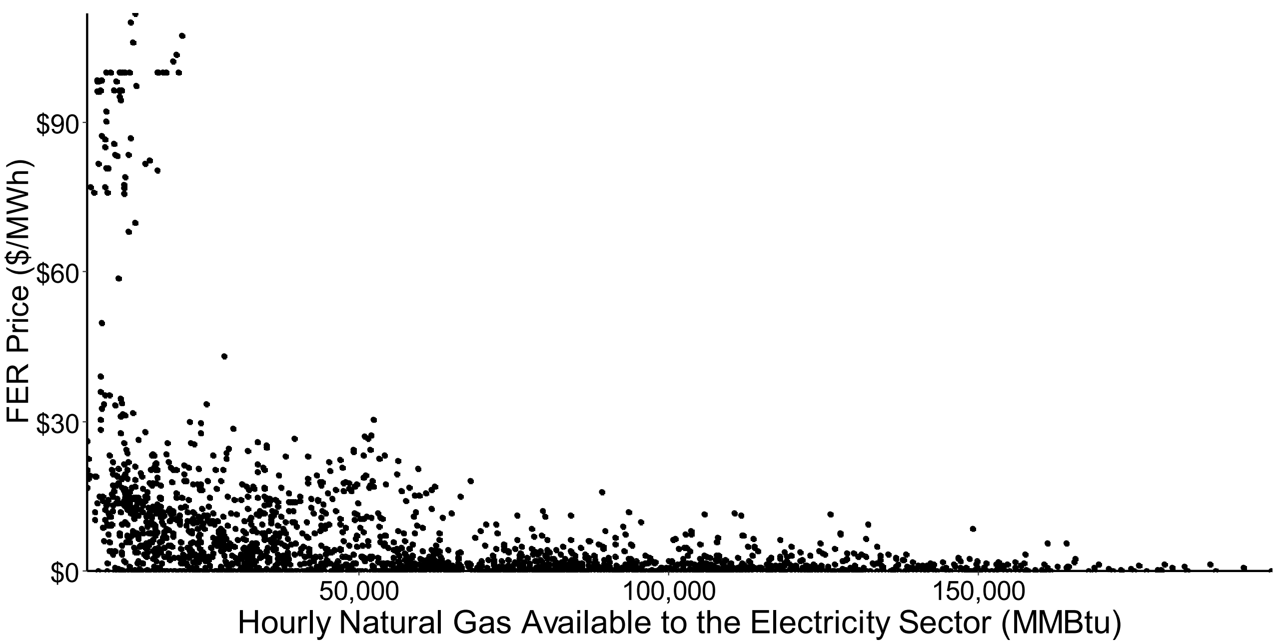
ii. Marginal Incentives for Energy Security

While the tables above estimate the change in total returns from holding fuel under ESI in each of the Central Cases, ***this incentive can also be assessed by evaluating the marginal revenues that ESI creates during periods of system stress.*** As with any market design, price signals for the desired service should be strongest when the need for these services is greatest. In this case, high prices for ESI services occur during tight market conditions when reliability needs are greatest and the higher cost offers must be relied on to supply ESI services. These high prices create strong incentives for resources to take the actions necessary to be able to provide options or energy at these times of need and to do so at lower cost than the marginal resource, thus allowing them to earn inframarginal revenues.

While we analyze these incentives in the context of decisions by oil-fired resource owners, it is important to remember that these incentives are not limited to specific generation technologies, and extend to any resources able to take actions to improve their ability to deliver energy supplies. Many resources can take actions to improve their ability to deliver energy supplies in real-time, including gas-fired resources (e.g., through forward fuel contracting arrangements, dual-fuel retrofits), hydropower resources (e.g., through preservation of reservoir levels), and demand-response resources.

Analysis of market outcomes shows that new revenue opportunities from ESI, including additional FER payments and returns from DA energy options, are greatest when market conditions are tight. **Figure 16** plots the FER price (on the y-axis) and the natural gas supply available to the electricity sector, a metric of system stress, (on the x-axis) for each hour in the Frequent Case. When natural gas supplies are limited (i.e., further left on the figure), causing high natural gas prices, fuel oil resources will be most competitive for supplying DA energy and DA energy options because their fuel costs remain fixed, regardless of upward movements in natural gas prices. As shown in the figure, FER prices are highest in these stressed conditions when the natural gas available for electric generation is low. Thus, the incentives ESI would create for greater fuel inventories would be strongest when reliability needs (e.g., natural gas limitations) are greatest and the value of additional fuel inventory for reliability is greatest.

Figure 16. FER Prices and Electricity Sector Natural Gas Supply, Winter Central Frequent Case



We analyze prices across the Cases and ESI products to assess the range of incentives to improve real-time delivery of energy supply. **Figure 17** provides hourly FER prices for each of the Central Cases. This figure (and those that follow) shows the distribution of prices, identifying the number of days (on the x-axis) that FER prices reach a given value (on the y-axis) for each Central Case. The figure highlights the large number of hours in which large FER payment rates exceed various values (e.g., above $20 per MWh) during the stressed conditions cases. For example, in the Frequent Case, the FER price exceeds $20 per MWh for 154 hours (on 28 different days) over the course of the winter. By contrast, FER payments reach high levels less frequently in the Infrequent Case, although they still exceed $10 per MWh in 93 hours (on 16 different days) over the winter. For resources earning FER payments, these revenues go directly to their profit margins, as these payments are in addition to the LMP.

Figure 17. Distribution of FER Prices, Winter Central Case

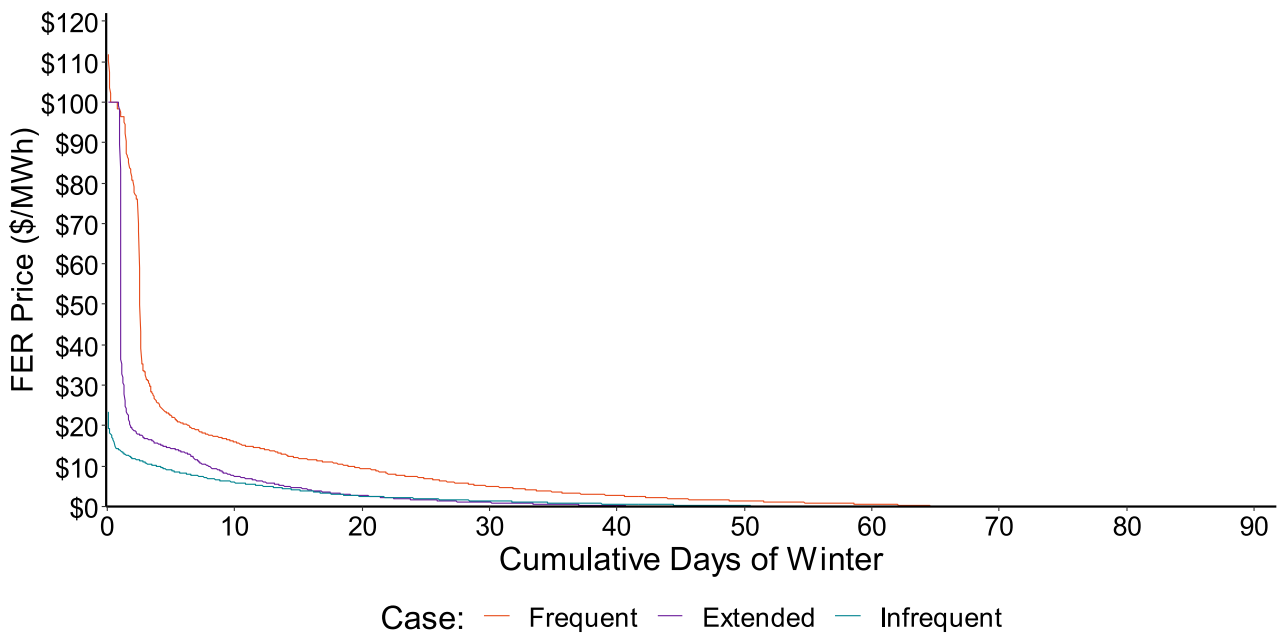


Figure 18 provides a similar hourly curve of GCR10 prices for each of the Central Cases. Consistent with the distribution of FER prices illustrated in **Figure 17**, GCR10 prices become elevated in many hours during the stressed cases, with prices exceeding $50 per MWh. **Table 14** provides another lens on the ESI price data, providing RER prices at various statistical percentiles within the hourly sample of hours. For example, in the Frequent Case, the 96th percentile RER price is $50.75 per MWh, indicating that prices are $50.75 per MWh or greater in 4% (100% minus 96%) of the hours. As there are 2,160 hours in the winter we analyze, this implies that RER prices are above $50 per MWh in at least 86 hours. In the Extended Case, prices are above $50 per MWh in 27 hours. Thus, even after accounting for the incremental energy incented by ESI, which will tend to reduce energy and ancillary service prices, DA energy option prices reach high levels in a sufficiently large number of hours to provide meaningful incentives for resources to take actions to improve their ability to deliver energy during such stressed conditions.

Figure 18. Distribution of GCR10 Prices, Winter Central Case

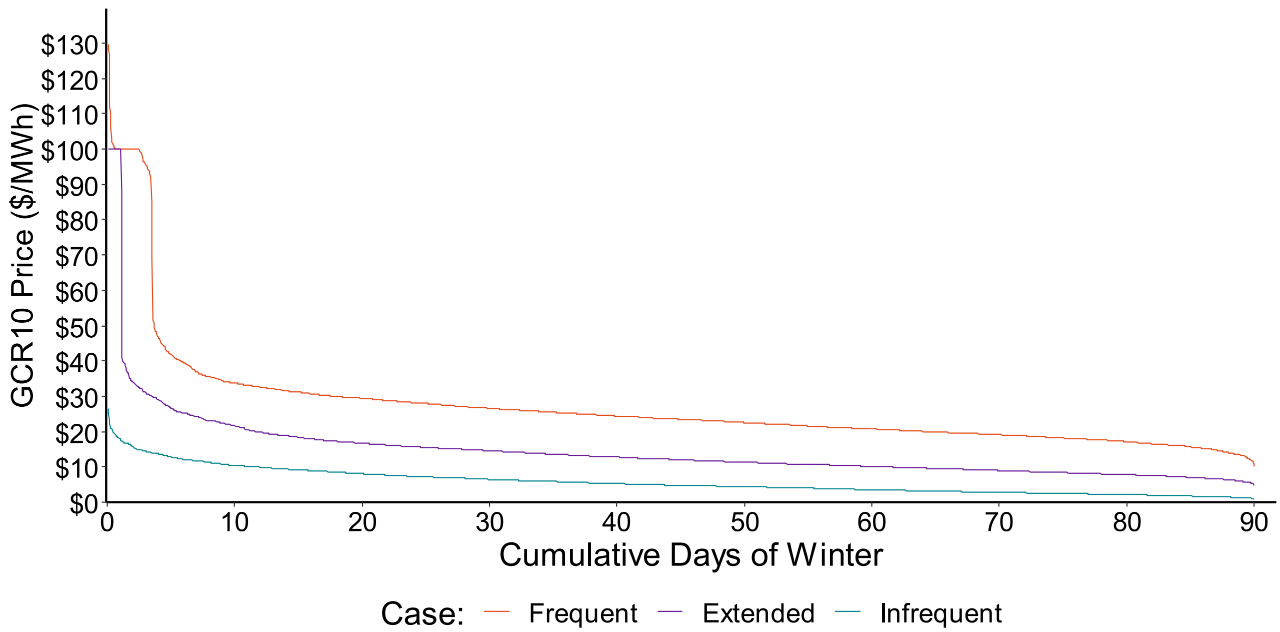


Table 14. Summary Statistics of RER Prices, Winter Central Case

	RER Percentile ($/MWh) Including Shortage Hours								
Cases	**25%**	**50%**	**75%**	**90%**	**95%**	**96%**	**97%**	**98%**	**99%**
Infrequent	$2.94	$4.76	$7.63	$10.66	$13.20	$13.92	$14.45	$16.13	$18.05
Extended	$9.26	$11.98	$16.05	$22.30	$26.99	$28.88	$30.65	$33.79	$100.00
Frequent	$19.51	$23.45	$28.63	$34.40	$43.91	$50.75	$97.54	$100.00	$100.00
All Cases	$6.88	$12.64	$21.21	$28.44	$32.90	$34.31	$37.56	$44.67	$100.00

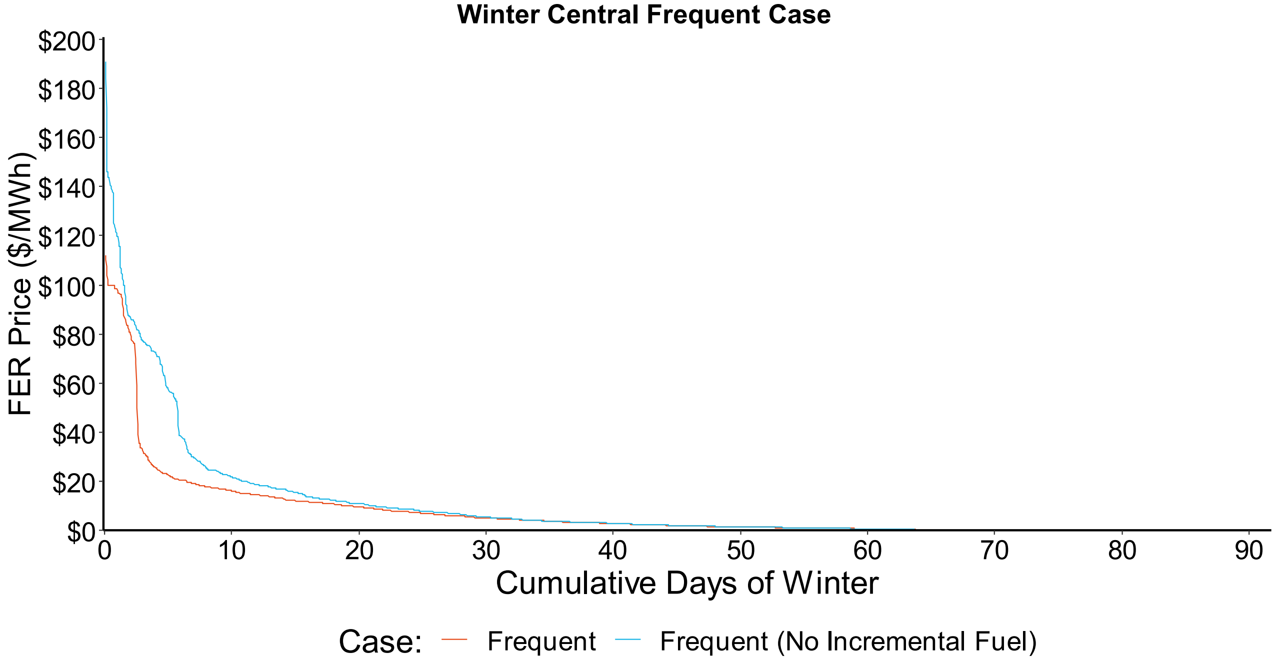
These tables and figures illustrate that ***the returns to incremental inventory are large when this inventory is available during these periods of system stress and therefore provides the greatest reliability benefit.*** For example, consider a unit that consumes residual fuel oil with a heat rate of 9,000 Btu/kWh. If the resource does not consume the fuel during the winter, it incurs a holding cost of approximately $13 per MWh to keep the fuel in inventory until the next winter.[45] However, if it consumes the fuel, then the resource earns a return equal to the incremental market revenues net of its production costs. Under current market rules, these revenues only include the LMP. But, under ESI, revenues would also include FER payments and the opportunity to supply DA energy options (which can be earned even in cases when the fuel is not ultimately used). As shown above, during periods of system stress, the ESI prices can be large, more than offsetting the holding cost. For example, in the Frequent Case, FER payments, which are made to resources that sell DA energy in addition to the DA LMP, exceed $13 per MWh in a large fraction of hours. Thus, investment in fuel

[45] This calculation also assumes $9.64 per MMBtu for refined fuel oil, and a holding cost of 15%. See the appendix for a more detailed explanation of how this value is calculated.

inventory can allow the resource owner to reap additional returns during periods of system stress, thus improving the reliability and enhancing the region's energy security.

In these exhibits, the frequency of high FER and ESI prices already reflects the incremental fuel supplies assumed under the ESI case. Thus, even after accounting for the effect on prices of assumed incremental fuel supplies under ESI, price signals for the ESI products remain strong in a meaningful fraction of hours. If our modeling had assumed no meaningful market response to the introduction of the ESI products, the frequency of these high prices would be even greater because less available fuel oil would decrease the energy supply and increase market prices. This suggests that resources that use fuel oil would have even stronger financial incentives to add oil to their tanks in response to the new products if the broader market response to ESI was more limited. This observation is demonstrated graphically in **Figure 19**, which shows the FER prices with and without the incremental fuel supplies assumed under ESI. As shown, absent the incremental fuel supplies, high FER prices are much more frequent, showing that the incentives to procure oil to sell DA energy (and ancillary services) would be even greater absent a robust market response.

Figure 19. Distribution of FER Prices with and without Incremental Fuel Winter Central Frequent Case



The particular design of ISO-NE's ESI proposal also has important consequences for the strength of the incentives it would create. During the stakeholder process, market participants raised the possibility of various changes to the ISO-NE proposal, such as eliminating certain ESI products from the design. Each of these changes would have consequences for the prices for each ESI product, which in turn would affect the incentives for market participants to incur costs to improve their real-time delivery of energy, consistent with ESI's objectives. For example, one change that has been discussed is the elimination of the RER. **Figure 20** and **Figure 21** illustrate the consequences of this proposal, in terms of the effect on incentives for energy inventory. Specifically, these figures show the distribution of prices for FER and GCR10 for the Central Frequent Case with and without the RER. In this no RER case, we assume that the additional energy inventory incented by ESI is only one-half the amount that would be incented with the full ESI proposal. (The details of this scenario are discussed further in our Scenario Analysis in **Section IV.C**.) Despite the assumption that the No RER scenario incents a lesser quantity of incremental energy inventory, the price of both FER and GCR10 is substantially lower without RER as compared to when RER being included in the ESI proposal. This difference in price levels demonstrates that the elimination of the RER from the ESI design would materially reduce the incentives for resource owners to take steps to improve their ability to deliver energy in real-time.

Figure 20. Distribution of FER prices with and without RER
Winter Central Frequent Case

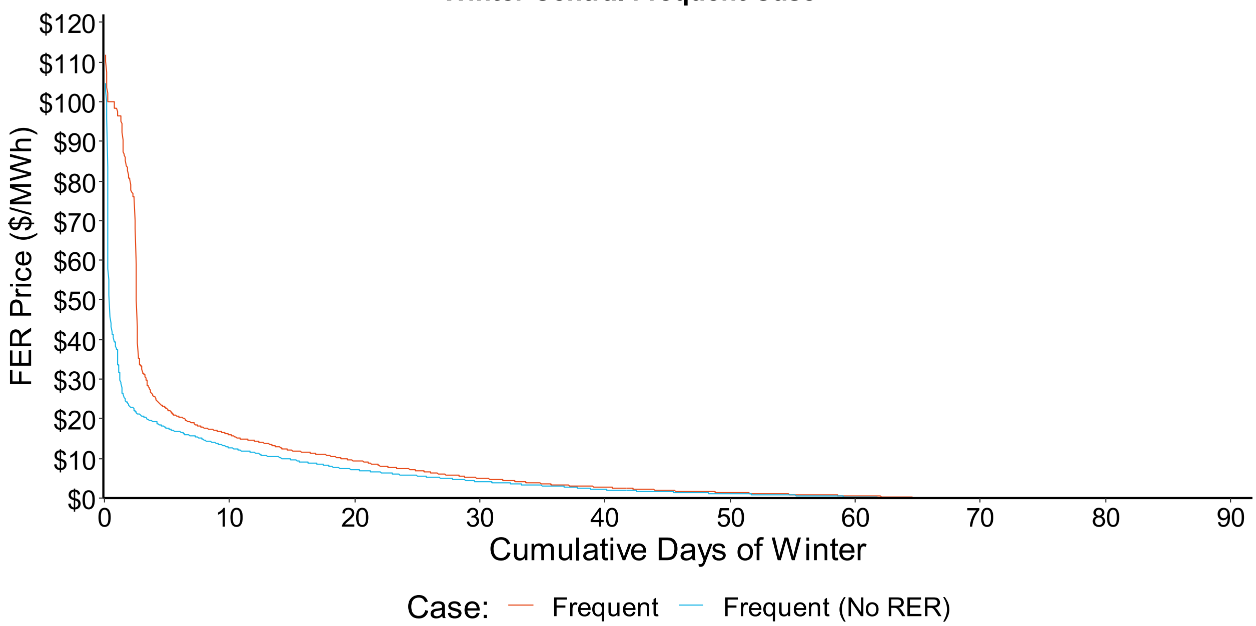
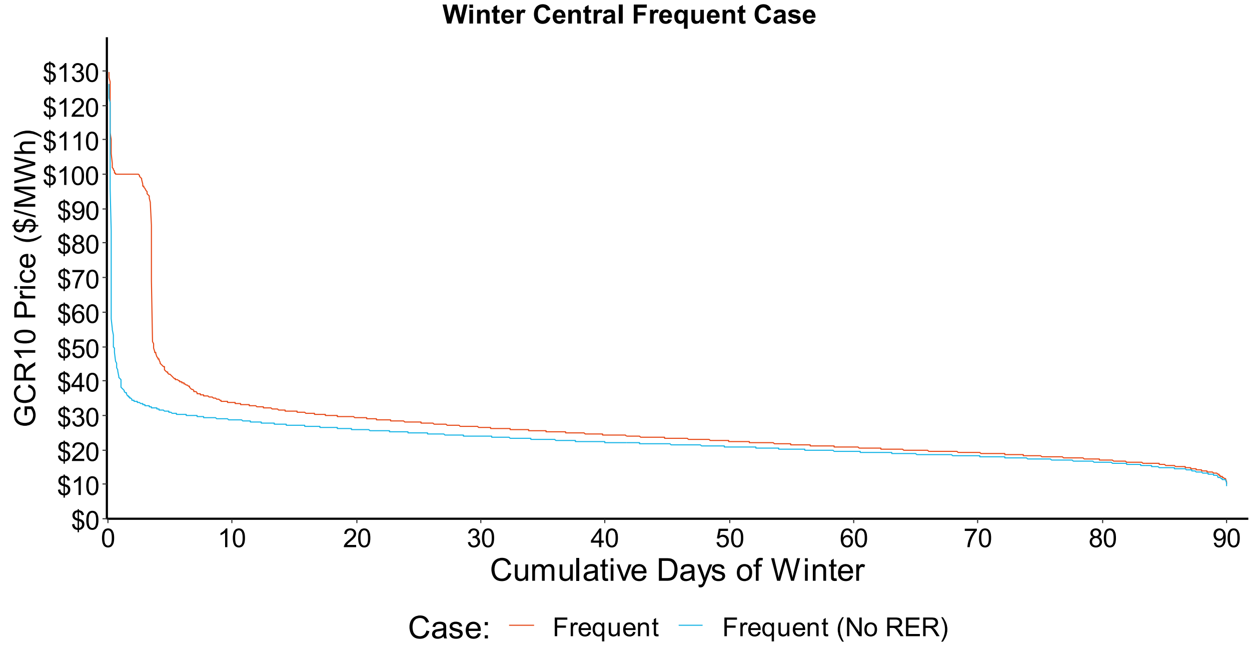


Figure 21. Distribution of GCR10 prices with and without RER
Winter Central Frequent Case



These results also show that the assumed incremental fuel inventory incented by ESI appears consistent with plausible responses by market participants. **Figure 16** to **Figure 19** demonstrate the new financial incentives created by ESI improve delivery of real-time energy during stressed system conditions. These figures show that, even after accounting for incremental inventory incented by ESI, there are still opportunities to earn substantial returns from supplying DA energy and DA energy options during periods of system stress by increasing the holding of fuel oil.

In total, analysis of hourly FER and ESI product pricing demonstrates the strong incentives that would be created by the ESI proposal. ***If adopted, ESI would expose market participants to greater financial risk if they sell forward positions that are not backed by physical inventory. These price signals would be strongest during stressed conditions, providing price signals that are aligned with the periods of need. During these periods of need, the incentives to take steps to improve deliverability will be greatest for those resources with the greatest risk of having fuel inventories reduced to the point that it constrains supply decisions, illustrating that ESI's incentives efficiently target those opportunities to increase inventory that would provide the greatest value to system reliability relative to their incremental costs.***

d) Incentives for Investment in Incremental Forward LNG Contracts

In addition to assessing ESI's impact on incentives to hold fuel oil, we also analyze the changes in incentives for a gas-only resource to enter into a forward contract with an LNG terminal under ESI as compared to current market rules. In contrast to fuel-oil inventory and refueling decisions, which are relatively continuous, these forward contracting decisions are more discrete, requiring resource owners to make a "yes/no" decision prior to the winter about entering into a contract. While ESI will increase the expected net revenues associated with forward LNG contracts, and may therefore increase the likelihood that gas resources enter into such contracts, the discrete nature of these contractual decisions, among other reasons, makes it more difficult to estimate the extent to which ESI will increase the amount of LNG available to the region through additional forward contracting.

At present, the LNG terminals have entered into various forward contracting arrangements with LDCs, some generators, and potentially other market participants. LNG terminal owners have indicated that they have the physical capability to expand forward contract volumes with New England market participants.

ESI would provide additional incentives for market participants to enter into additional forward contract volumes with the LNG terminals. Like the fuel oil resources analyzed in the prior section, these additional revenues potentially come through FER payments and the sale of DA energy options. **Table 15** provides our analysis of the potential incremental revenues under ESI to the holder of a forward LNG contract.[46] In this analysis, the resources assumed to hold the forward contract clear all of the energy supply supported by these contracts through DA (and RT) energy, but supply no DA energy options. This pattern of supply reflects a combination of factors, including the timing and severity of stressed market conditions in the particular winter Cases evaluated. Thus, the potential gains considered in our quantitative analysis reflect only incremental FER

[46] These revenues reflect an assumed forward contract with a strike price of $10 per MMBtu, 10 calls and no take-or-pay obligation. In practice, generators and LNG terminals may enter into different contract structures. To the extent that these alternative contract structures are preferred, they may provide greater net benefits, and thus present a lower gap to contracting than the estimated gap assuming the call option contract structure.

payments, although, as we describe below, we expect other incremental benefits that are not captured in our analysis.

In the cases representing stressed market conditions, ESI would provide incremental revenues of $2,066 and $1,511 per MW in the Frequent and Extended Cases, respectively. The analysis assumes that the resource with the forward LNG contract would use the fuel to supply incremental DA energy that it otherwise would not supply without the forward LNG contract. In this sense, our quantitative estimates may provide an upper bound on the incremental FER revenues from the direct use of the forward LNG contract supplies.[47] By contrast, there are no incremental revenues in the Infrequent Case because weather conditions are so mild that gas prices are not high enough to exercise any calls on natural gas supplies under the contract.

Table 15. Forward LNG Contract, Incremental ESI Revenues from FER Payments, Winter Central Case

Severity	FER Hours	FER Price [A]	FER MWh [B]	FER Payments ($) [C] = [A]*[B]	FER Payments ($/MW)
Frequent Case	240	$8.70	146,311	$1,273,243	$2,066
Extended Case	240	$6.36	146,311	$931,241	$1,511
Infrequent Case	0	NA	0	$0	$0

The quantitative analysis captures some but not all of the potential gains from a forward LNG contract under ESI. It may therefore understate the incremental incentives that ESI provides to enter into such contracts. One issue is the relatively simple (static) decision-making rules used to exercise the call options. We assume that call options are not exercised unless natural gas prices exceed the strike price by a fixed threshold,[48] based on analysis of historical data. With more complex decision-making rules for determining when to exercise call options, where this threshold varies based on the number of remaining calls and expected market conditions, the contract could potentially earn higher returns than those presented in **Table 15**. For example, the contract holder earns no returns in the Infrequent Case, although relaxing the threshold prices for exercising the call options could provide the holder with some gains from the contract.

A second issue is that our analysis does not capture the gains from reduction in financial risk under certain market conditions. In particular, while the analysis captures the gains from reductions in risk when natural gas prices are relatively high (e.g., exceeding the LNG price) and the resource sells DA energy, it does not account for risk benefits when prices are relatively low (e.g., less than the LNG price), where the resource sells DA energy options. More specifically, a forward LNG contract would cover intra-day fuel price risk for a gas-only facility awarded a DA energy option on a day when natural gas prices are relatively low. Without the forward

47 In aggregate, the forward LNG contract would be expected to increase gas-only DA energy supply, as some oil-fired generation is displaced by gas-only generation. But, many factors potentially affect which resources earn those incremental FER payments, including the efficiency (heat rate) of the unit with the forward LNG contract, the portfolio of resources owned by the contract-holder, and other market trading arrangements available through which the contract-holder could earn a premium on the sale of its natural gas supply.

48 The analysis assumes a static threshold for exercising the call options ($16 per MMBtu) that is above the commodity price ($10 per MMBtu). The higher threshold for exercising the call option accounts for the opportunity cost to exercising one of the limited number of call options. It ensures that the owner does not exercise the call to earn a small return, thus precluding a potential future return of higher magnitude. This threshold was calculated using quantitative analysis of historical New England market conditions.

LNG contract, the unit selling the option would face the risk that real-time energy and gas prices would increase dramatically the next day. Because the strike price would remain in line with the lower DA LMP, an increase in the resource's marginal costs due to the higher real-time gas price would leave the resource owner exposed to the risk of large losses. A forward LNG contract would help mitigate this risk, a benefit that is not captured quantitatively. As a result, the analysis presented may understate ESI's impact on resource incentives to enter into such forward LNG contracts.

Under current market rules, there may be a gap between prices a generator and LNG terminal are willing to accept for a forward LNG contract. Prior work estimated this gap to be $2,705 per MW in the context of establishing a compensation rate for the Interim Program.[49] This analysis did not attempt to account for the heterogeneity in this gap among market participants. In practice, the magnitude of this gap likely varies across market participants, with some higher and others lower than this estimate. For example, some market participants have entered into forward LNG contracts in recent winters, implying there is no gap for their resources under current market rules and conditions.

Incremental ESI revenues may close whatever gap there is between additional generators and the region's LNG terminals to reaching agreement. In the Frequent and Extended Cases, incremental ESI revenues are of the same order of magnitude as the amount that was estimated to be necessary to incent LNG contracting in the context of the Interim Program. That is, the incremental revenues are $2,066 per MW in the Frequent Case and $1,511 per MW in the Extended Case, as compared to an estimated gap of $2,705 per MW. Thus, these incremental revenue streams due to ESI would potentially incent some resources toward entering into such contracts that they otherwise would not enter into.

2. Supply of Energy and DA Energy Options

The ESI proposal is expected to result in multiple changes to day-ahead and real-time energy supply, including changes in the supply of energy (clearing in the day-ahead market), shifts in the composition of resources supplying energy in both day-ahead and real-time markets, and a new supply of DA energy options that are not procured under current market rules.

Historically, the supply of physical energy clearing in the day-ahead markets has been less than the ISO-NE load forecast, on average. **Table 16** compares the quantity of cleared physical DA energy to the ISO-NE load forecast in our winter CMR Cases, which is based on historical cleared DA energy and load forecasts. Under current market rules, when the day-ahead market clears physical energy supplies below the ISO-NE load forecast, resources in the market implicitly supply load with an option to provide additional energy needed to meet load in real-time. This option is exercised through a variety of means, including supplemental reliability commitments by ISO-NE after the day-ahead market has cleared. These supplemental commitments may cause additional resources to be committed if the reliability analysis determines that the additional energy that can be provided from the resources cleared in the day-ahead market or that can quickly come online are not sufficient to meet ISO-NE's load forecast. Even if additional units are not committed, reliability may be maintained through the ramp capability of units that clear a portion of their operating capacity in the day-ahead

[49] Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

market or through the reliance on fast start resources. These services are presently uncompensated, and as a result, the financial incentives for such resources, which ISO-NE is implicitly counting on to meet its reliability needs, to take the necessary actions to be available if called may not be consistent with the services they provide.

Table 16. Percent of Hours with Cleared Supply Less than Forecast Load, Winter CMR Case

	Cleared DA Energy Supply < ISO Forecast Load	
CMR Case	**Share of Hours (%)**	**Average Difference (MW)**
Frequent Case	92%	519
Extended Case	64%	334
Infrequent Case	81%	383

Note: The load forecast depicted in the table is the forecast available prior to clearing the day-ahead market, at around 9:30am on OD-1.

An important element of the ESI design is the increase in cleared DA energy caused by the co-optimization of the DA energy and EIR awards, and the expected increase in day-ahead bid-in demand. **Section III.B.5** described these adjustments in greater detail. In short, with ESI, social surplus may be maximized by buying more DA energy to reduce the gap between cleared DA energy and the forecast load, and thereby limiting the quantity of EIR that is procured to satisfy the FER. Day-ahead bid-in demand increases to eliminate arbitrage opportunities between the day-ahead and real-time markets, which further reduces the gap between cleared DA energy and the forecast load.

Table 17 shows the changes in cleared DA energy by resource type between CMR and ESI during the winter Central Cases. Under CMR, the total energy clearing in the day-ahead market ranges from 31.0 to 31.5 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges from 31.6 to 32.2 TWh (column [B]), representing an increase of 0.4 to 1.0 TWh of DA energy supply. Thus, ESI leads to increases of 1.4% to 3.3% in DA energy compared to current market rules.[50]

Table 17. Changes in Cleared DA Energy, Winter Central Case
CMR vs ESI (MWh)

	CMR	ESI		Difference	Real-Time Comparison	
Case	**Day-Ahead Energy [A]**	**Day-Ahead Energy [B]**	**Cleared EIR [C]**	**Day-Ahead Energy [D] = [B] - [A]**	**Real-Time Demand**	**Energy + EIR [E] = [B] + [C]**
Frequent Case	31,188,025	32,215,469	6,604	1,027,443	32,155,711	32,222,073
Extended Case	31,503,187	31,943,398	25,172	440,211	31,840,458	31,968,570
Infrequent Case	31,047,336	31,634,655	83,245	587,318	31,525,206	31,717,899

50 Note that, under ESI, the sum of DA energy and EIR across the winter exceeds the real-time energy demand in each of the Cases. This occurs because, while ESI generally avoids under-procurement day-ahead by procuring DA energy and EIR to cover the forecast load, it does not prevent the day-ahead market from clearing more physical energy than the load forecast, which can occur for a variety of reasons, including risk hedging and price expectations.

Table 18 provides the total quantity of DA energy and DA energy options procured in each Central Case. In total, 7.7 to 7.9 GW of DA energy options are procured across the three Cases. The vast majority of these DA energy options are procured for GCR and RER. The quantity of RER procured in the Frequent and Extended Cases is less than the maximum quantity because, in some hours, procuring the full requirement (1,200 MW) is either infeasible or would require substitutions with (marginal) costs greater than the RER penalty factor value ($100 per MWh). Thus, in these hours, the market procures a quantity of DA energy options less than the RER requirement rather undertake additional purchases that would cause the RER price to rise above the RER penalty factor value.

Table 18. Cleared DA Energy and Ancillary Service Products, Winter Central Case, ESI (MWh)

		DA Energy Options				
Case	**Day-Ahead Energy**	**Total**	**EIR**	**GCR10**	**GCR30**	**RER**
Frequent Case	32,215,469	7,749,058	6,604	3,456,000	1,728,000	2,558,454
Extended Case	31,943,398	7,791,810	25,172	3,456,000	1,728,000	2,582,638
Infrequent Case	31,634,655	7,859,245	83,245	3,456,000	1,728,000	2,592,000

Note: The quantity of GCR30 reflects the nested GCR30 quantity, incremental to the GCR10 quantity, not the total GCR30 requirement. The RER quantity reflects the total quantity of DA energy options procured, exclusive of amounts not procured because RER prices are constrained by the penalty factor.

The increases in DA energy occur during hours when the energy supply clearing in the day-ahead market would be less than the ISO-NE load forecast under current market rules. However, the substitution of DA energy for EIR does not completely eliminate the gap between cleared DA energy and the ISO-NE load forecast.[51] For each Case, column [C] shows the quantity of cleared EIR, which ranges from 6.6 to 83.2 GWh. Thus, the EIR quantity is small compared to the difference in DA energy under CMR and ESI, indicating that ESI is expected to reduce the gap between cleared DA energy supply and the ISO-NE load forecast that exists under the current market rules.

Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. **Table 19** to **Table 21** show the impact of ESI on the products supplied in the day-ahead markets across resource types. Because of the increase in total DA energy caused by ESI, most resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), oil-only steam units and dual-fuel combustion turbines.

DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only). For some of these resource types, under ESI, DA energy options become a large share of the services provided in the day-ahead market. At one extreme, oil-only non-steam combustion turbine units supply about 10 times the amount of DA energy options compared to DA energy. Pumped storage and dual fuel combustion turbines

[51] In these hours, procuring additional DA energy options to provide EIR results in greater social surplus than clearing additional DA energy. More specifically, the costs associated with procuring these options is less than the social surplus loss associated with procuring more DA energy (i.e., the difference in price between incremental demand bids and supply offers).

also supply similarly large fractions of DA energy options relative to DA energy. At the other extreme, combined cycle units (gas-only and dual fuel) supply about 10 times the amount of DA energy relative to DA energy options. Thus, the cost-effective allocation of DA energy and DA energy options considers both the cost of supplying energy – with the lowest marginal cost resources generally selected – and the cost of supplying DA energy options.

There is some substitution between DA energy and DA energy options for some resource types. For example, although total DA energy increases under ESI relative to CMR, supply from oil-only combustion turbines decreases. However, this decrease is offset by a large supply of DA energy options provided by these resources. For example, in the Frequent Case, DA energy from oil-only combustion turbines decreases by 29,182 MWh (more than a 10% decrease), while these resources sell 2.0 TWh of DA energy options.

Table 19. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Frequent Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	18,559	18,810	0	251
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,601,428	1,601,638	0	211
Coal	535	957,230	964,935	10,540	7,705
Dual Fuel - CC	6,392	5,887,192	6,225,924	414,403	338,733
Dual Fuel - CT	1,435	697,219	739,743	1,297,907	42,525
Fuel Cell	21	35,109	35,123	0	15
Gas - CC	7,583	3,131,703	3,467,244	405,473	335,541
Gas - CT	404	669	704	280,643	35
Gas with LNG under ESI	616	1,020,701	1,076,091	67,815	55,390
Hydro	1,987	1,251,996	1,251,996	790,887	0
Imports	2,850	6,096,019	6,099,641	0	3,622
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	1,290,766	1,560,537	217,653	269,771
Oil Only - CT	2,511	194,309	165,127	2,003,399	(29,182)
Pumped Storage	1,778	616,108	616,108	2,251,837	0
Solar	1,671	152,197	152,197	0	0
Wind	1,401	992,964	992,964	0	0

Note: (1) DA energy for battery storage and pumped storage reflect (on-peak) discharged supply, and is not net of (off-peak) charging withdrawals.
(2) Oil Only - CT is largely combustion turbine units, but also include internal combustion engines.

Table 20. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Extended Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	23,846	11,850	0	(11,996)
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,581,343	1,577,716	0	(3,627)
Coal	535	646,721	652,128	9,048	5,406
Dual Fuel - CC	6,392	5,416,572	5,618,953	397,252	202,381
Dual Fuel - CT	1,435	470,553	494,509	1,428,271	23,956
Fuel Cell	21	23,202	23,316	0	115
Gas - CC	7,583	4,729,551	4,933,753	264,301	204,202
Gas - CT	404	0	0	304,397	0
Gas with LNG under ESI	616	1,242,134	1,287,505	34	45,372
Hydro	1,987	1,526,266	1,526,266	1,123,614	0
Imports	2,850	5,929,432	5,931,763	0	2,331
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	619,222	641,855	35,773	22,634
Oil Only - CT	2,511	116,800	64,788	1,148,060	(52,012)
Pumped Storage	1,778	616,108	616,108	3,080,047	0
Solar	1,671	245,603	245,603	0	0
Wind	1,401	1,083,132	1,083,132	0	0

Note: See note for **Table 19**.

Table 21. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Infrequent Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	4,246	4,380	0	134
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,559,242	1,559,753	0	510
Coal	535	549,273	558,894	15,725	9,621
Dual Fuel - CC	6,392	5,170,503	5,443,353	357,917	272,850
Dual Fuel - CT	1,435	362,534	362,669	1,526,744	135
Fuel Cell	21	12,645	13,162	0	517
Gas - CC	7,583	5,543,212	5,830,502	291,525	287,290
Gas - CT	404	74	74	393,496	0
Gas with LNG under ESI	616	1,316,801	1,316,801	0	0
Hydro	1,987	1,421,185	1,421,185	1,137,865	0
Imports	2,850	5,850,967	5,856,778	0	5,811
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	931,752	931,752	0	0
Oil Only - Steam	3,792	51,739	61,149	2,058	9,410
Oil Only - CT	2,511	2,553	3,556	1,324,243	1,003
Pumped Storage	1,778	616,108	616,108	2,809,637	0
Solar	1,671	289,960	289,960	0	0
Wind	1,401	1,017,230	1,017,230	0	0

Note: See note for **Table 19**.

The mix of energy supply varies across time with changes in market conditions, including load levels, natural gas supply available to the electricity sector (given weather-related variation in LDC natural gas demand), and the available natural gas supplies, which when tight, may cause a drawdown in energy inventories. **Figure 22** illustrates the hourly cleared supply of DA energy by technology type in the Frequent Case. The figure illustrates the shifts in supply that occur during periods of tight natural gas supplies, where awards to generators using oil (dual fuel is purple, oil-only is black) are generally increasing compared with periods with less stressed market conditions because of the energy inventories upon which these resources can draw.

Figure 22. Hourly Cleared DA Energy by Resource Type

ESI, Winter Central Frequent Case (MWh)

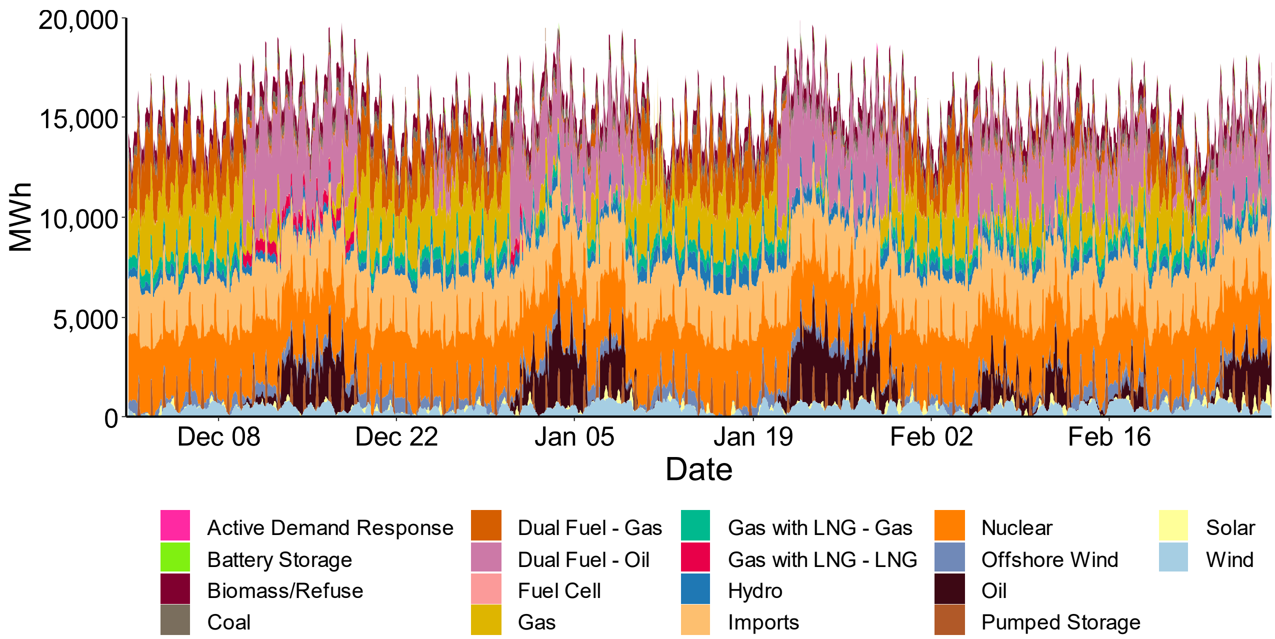
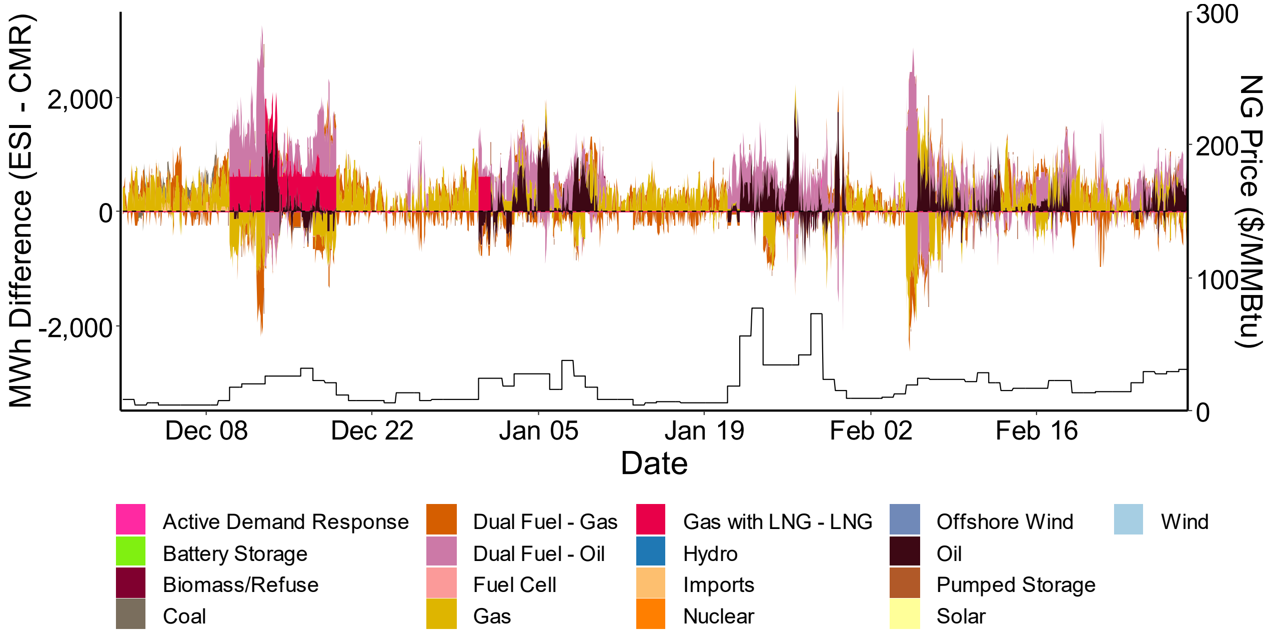


Figure 23 shows the mix of resources that make up differences in cleared DA energy between CMR and ESI in each hour in the Frequent Case. In each hour, the difference in DA energy supply reflects increases by some resources (shown by amounts greater than zero) and decreases by others (shown by amounts less than zero). As discussed above, in each hour, the quantity of DA energy increases under ESI compared to CMR. But, the figure shows that this increase in energy can reflect added supply from some resources, and a decrease in supply by others. For example, between December 9 and December 18, DA energy increases from oil-fired dual fuel and gas-fired units supported by a forward LNG contract, while DA energy decreases from gas-only resources (relying on pipeline natural gas), as this period corresponded with high pipeline gas prices. The figure illustrates the range of substitutions that occur between the CMR and ESI cases given the many dynamic factors captured by the model. These shifts in supply among resource types are largest during periods when the natural gas price is high (as shown by the lower line, right-hand y-axis). Thus, the figure illustrates how the impact of ESI on resource use is greatest during periods of system stress, given the greater

incremental energy inventory under ESI and substitution of supply (DA energy and DA energy options) among different technology types.

Figure 23. Difference in Hourly Cleared DA Energy by Resource Type CMR vs ESI, Winter Central Frequent Case



3. Production Costs

Production costs are a commonly used metric for evaluating the social costs of producing goods and services. As such, changes in production costs can signal how policy or regulatory proposals affect a market's efficiency, and we use this metric to assess whether ESI appears likely to reduce the costs to meeting electricity demand. While our evaluation of production costs appropriately captures the social cost of the physical resources used by generators to meet customer loads, it may not encompass all social costs and benefits. For example, production costs may not capture certain financial costs and changes in utility, although capturing these effects would be very challenging and beyond the scope of our analysis.[52]

The ESI proposal would be expected to lower total production costs incurred to meet real-time loads through multiple effects, including the additional energy inventory incented by ESI, the shifts in energy supply through changes in energy inventory use, and the more efficient unit commitment to meet real-time operating reserves. These additional fuel supplies would be expected as a result of new incentives from ESI for resources to increase energy inventories and otherwise increase the ability of resources to deliver energy supply in real-time (e.g., through general improvements in operational performance). With larger

[52] ESI may cause a range of effects to financial cost and underlying utility of consumers. The procurement of DA energy options, for example, may impose financial costs if it causes changes to market participant's financial structures to account for changes in financial risk. However, accounting for these costs would be extremely complex, particularly given the potential for ESI to have spillover effects on other market operations.

energy inventories (and better resource performance), the cost of meeting real-time loads would be reduced, particularly during periods of tight fuel supply when the market would otherwise require that load be met through more costly generation resources. These reductions in production costs are consistent with an increase in market efficiency, reflecting actions to improve energy deliverability in tight market conditions, rather than the underinvestment in energy security that can occur under current market rules, identified as the "misaligned incentives" problem in the ESI White Paper. ESI would also be expected to change production costs in other ways that are not fully captured in our model, notably through more efficient unit commitment to meet real-time operating reserves. As a result, these results may understate any reductions in production costs that ESI produces.

Table 22 shows the estimated change in total production costs. The estimate of total production costs includes the marginal cost of production, including fuel and variable costs.[53] For example, in the Frequent Case, total model production costs are $1.42 billion under CMR and $1.37 billion under ESI, resulting in a $40.7 million reduction in model production costs. Under ESI, the quantity of energy held in inventory at the end of the winter season is greater than under CMR. The estimated change in cost of holding this fuel until the beginning of the next winter season is $5.3 million. Netting these holding costs from the $40.7 million reduction in production costs of supplying energy to load results in a change in total production costs of $35.5 million. Results are similar in the Extended Case, with total production costs reduced by an estimated $19.3 million, reflecting a reduction in model production costs of $25.0 million and an increase in holding costs of $5.7 million.

Table 22. Difference in Production Costs, Winter Central Case
CMR vs ESI ($ Million)

Case	Total Model Production Costs [1] ($ Million)			Incremental Energy Inventory Costs with ESI [2] ($ Million)	Change in Total Production Costs ($ Million)
	CMR	ESI	Change		
Frequent Case	$1,415.1	$1,374.4	($40.7)	$5.3	($35.5)
Extended Case	$939.5	$914.5	($25.0)	$5.7	($19.3)
Infrequent Case	$657.2	$656.3	($0.9)	$8.5	$7.5

Notes:
[1] Production costs only do not include opportunity costs.
[2] Incremental energy inventory costs include LNG and oil holding costs for incremental fuel at the end of the winter.

In contrast to the Frequent and Extended Cases, costs increase in the Infrequent Case by $7.5 million, reflecting a $0.9 million reduction in total model production costs and an increase in energy inventory holding costs of $8.5 million. Thus, these results suggest that ESI may not lower production costs under all market conditions.

These results show that ESI operates in a manner similar to insurance with respect to total economic costs. Similar to insurance, ESI would be expected to increase energy inventory, providing increased economic

[53] Estimated production costs exclude costs associated with nuclear, pumped storage, hydropower, wind power and solar, which are unchanged between the CMR and ESI model runs.

"protection" that lowers costs during periods of tight market conditions. However, similar to insurance, the cost of this protection may not always produce benefits that outweigh the costs, especially during "mild" conditions.

4. Emissions

Shifts in the mix of energy supply caused by ESI would lead to corresponding changes in total emissions given differences in the emission rates of individual resources in the fleet. **Table 23** shows the change in emissions between CMR and ESI for each of the Central Cases. Estimates of changes in total emissions reflect resource-specific emission rates and shifts in RT energy supply between resources. Emissions increase in some cases, and decrease in others. For example, carbon dioxide and sulfur dioxide emissions decrease in two of three cases. By contrast, oxides of nitrogen emissions increase in all three cases.

Table 23. Difference in Emissions, CMR vs ESI, Winter Central Case

	Total					
Case	**CO_2 (lbs)**		**SO_2 (lbs)**		**NO_X (lbs)**	
Frequent Case	124,298,774	0.63%	211,494	1.45%	1,372,155	4.44%
Extended Case	(53,987,006)	-0.31%	(109,636)	-1.26%	197,090	1.10%
Infrequent Case	(5,232,664)	-0.03%	(5,551)	-0.09%	19,985	0.17%

The primary driver of these changes in total emissions are the shifts in energy supply across various technology types. As described in **Section IV.2**, the shifts in energy supply due to ESI are quite complex. Moreover, even within technology types, emission rates are not uniform across units due to differences in generation efficiency (heat rates) and pollution control equipment (i.e., emissions per MMBtu fuel consumed). **Table 24** provides the change in total fuel consumption under ESI (compared to CMR) for each Central Case.

Table 24. Difference in Fuel Consumption by Fuel Type, CMR vs ESI, Winter Central Case

	Total					
Case	**Natural Gas (MMBTU)**		**Oil (BBL)**		**Coal (MMBTU)**	
Frequent Case	(2,053,357)	-4.21%	303,106	3.59%	-	0.00%
Extended Case	(30,051)	-0.04%	(68,471)	-1.74%	-	0.00%
Infrequent Case	-	0.00%	(4,752)	-0.36%	-	0.00%

5. Customer Payments

Total change in customer payments due to the ESI proposal will reflect a combination of factors:

- ***First, total LMP payments through day-ahead and real-time markets will shift due to a combination of factors.*** Several factors put downward pressure on LMPs, which will tend to reduce consumer costs. These factors include the increased supply of energy in inventory due to ESI's incentives to secure increased energy inventory, and the increase in supply of energy clearing the day-ahead market given the substitution of DA energy for EIR (which *lowers* LMPs because the DA LMP is generally set based on the offer price of the marginal bid-in demand). On the other hand, the shift in the energy mix due to various intra-hour and inter-hour substitutions within the market could increase LMPs.

- ***Second, resources supplying DA energy will receive FER payments as compensation for contributions to meeting the FER.*** This will tend to increase consumer payments.
- ***Third, consumers will make new payments to procure energy options in the day-ahead market.*** When RT LMPs are above the strike prices, load will be credited for the settlement of these options, equal to this price difference. This real-time settlement will partially offset the day-ahead payments for the options, but to the extent that participants include a risk component in their offer price, this closeout settlement is unlikely to fully offset the day-ahead payment, on average.

Table 25 summarizes the net impact of these three components on total customer payments. In the Infrequent Case, payments increase by $35 million over the 3-month winter (a 2.0% increase), reflecting an increase in payments to energy of $20 million (reflecting a $41 million reduction associated with decreased LMPs and a $61 million increase in payment due to FER payments) and net payments of $15 million for DA energy options.

Total payments both increase and decrease in the stressed conditions cases. In the Frequent Case, payments increase by $132 million (a 3.2% increase), reflecting a decrease in LMP payments of $183 million, FER payments of $250 million and net DA energy option payments of $66 million. In the Extended Case, however, payments decrease by $69 million (a 2.5% decrease), reflecting a decrease in LMP payments of $214 million, FER payments of $113 million and net DA energy option payments of $32 million.

Table 25. Total Payments, Winter Central Case ($ Million)

		Frequent Case				Extended Case				Infrequent Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

The aggregate totals in **Table 25** mask hourly variation in these impacts across the winter. This hourly variability is particularly important for the new ESI products, given the novel settlement structure of the new energy options commodity. Payments for the ESI products reflect both upfront payments for the DA energy options and settlement of the options, which provides offsetting compensation to load. **Figure 24** to **Figure 26** shows these net effects at the hourly level to illustrate the variability in net impacts. More specifically, **Figure 24** shows the upfront payments for the DA energy options in each hour over a 14-day period. These payments are generally in the range of $40,000 to $140,000 per hour and remain relatively stable across hours, suggesting that before the day-ahead market is run, option sellers may have similar expectations about potential closeout costs across hours.

Figure 24. Hourly DA Energy Option Payments
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

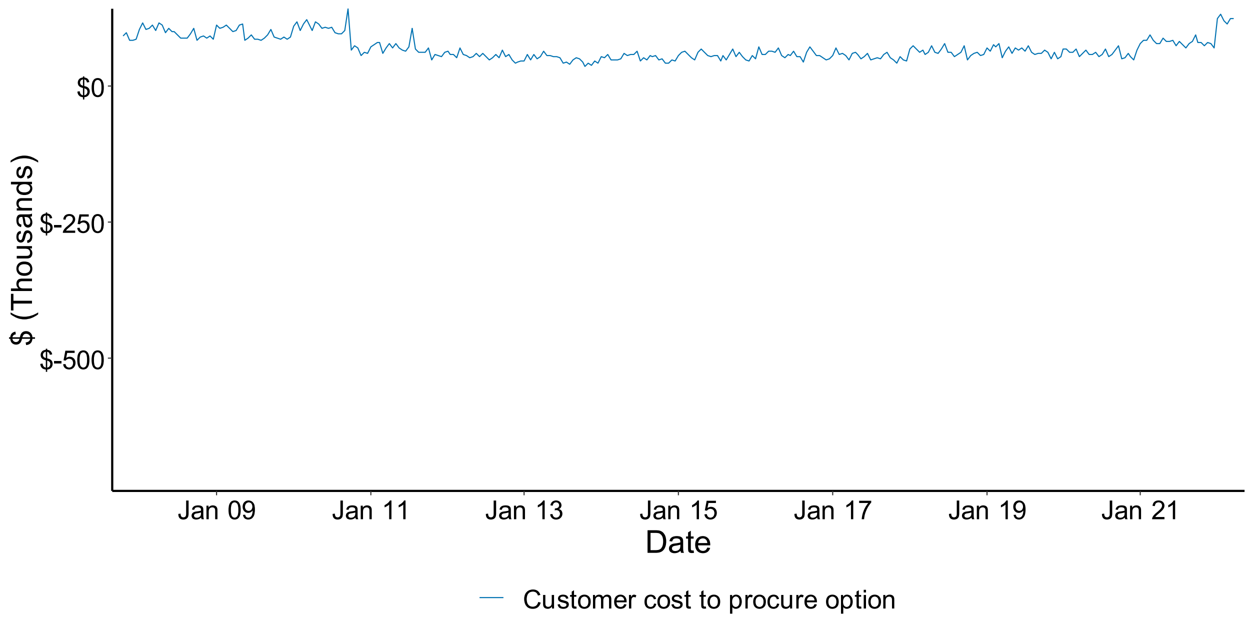


Figure 25 includes the same payments as **Figure 24**, and adds the real-time settlement of the options, which has the opposite sign, as it represents a charge to generation and a rebate to load. This value is $0 in many hours, indicating that the RT LMP is less than or equal to the strike price, and the option closeout cost is $0. However, in some hours, this closeout cost is significant as the RT LMP exceeds the strike price by some margin, suggesting that while sellers may have expected similar closeout costs across hours, they varied significantly.

Figure 25. Hourly DA Energy Option Payments and RT Option Settlement
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

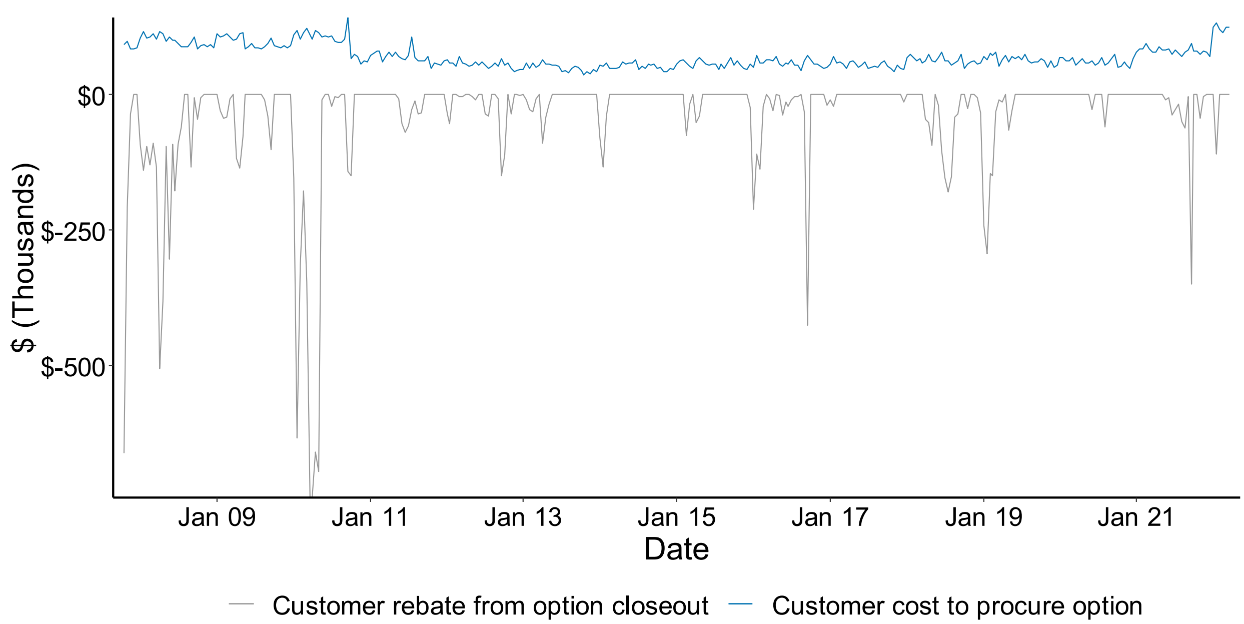


Figure 26 includes both the initial costs to procure the options and the settlement, and adds the total option costs, equal to this initial cost less the closeout. As the figure illustrates, the net cost to consumers is positive in many hours, but it also results in a net rebate in some hours, as the settlement rebate exceeds the initial cost to procure the option.

Figure 26. Hourly DA Energy Option Payments, RT Option Settlement and Net Payments
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

6. Resource Net Revenues

The impact of ESI on the net revenues earned by resources participating in the New England energy markets depends on a combination of factors. In aggregate, changes in payments by load will lead to corresponding changes in revenues to generators. Thus, in Cases when payments by load are expected to increase, this would be expected to lead to a corresponding increase in revenues to resource owners.

Table 26 to **Table 28** provide the average net revenues by resource type for the Frequent, Extended and Infrequent Cases, respectively.[54] Unlike the analysis of incentives for energy inventory, the change in net revenues accounts not only for the additional FER payments and DA energy option net revenues, but also reductions in LMPs caused by the larger energy inventories.[55] With a few exceptions, net revenues increase

[54] **Table 26** to **Table 28** do not include certain technology types, when our modeling of the resource dispatch is not sufficiently detailed to accurately characterize expected impacts. For example, output (and charging load) for battery and pumped storage reflect historical profiles, not economic offers, and thus may not accurately capture resource responses to ESI.

[55] For the purposes of evaluating net revenues, we consider all changes in payments, including any reductions in LMPs that would occur due to increases in energy inventories in response to ESI's incentives. While it is sensible to include these effects when evaluating net revenues, when evaluating ESI's incentives to improve delivery of energy in real-time, we focus on the direct incentives created by ESI, while acknowledging that this indirect effect on LMPs may dampen the magnitude of the response to these incentives.

for each resource type in Cases when payments by load are greater (i.e., the Frequent and Infrequent Cases), and net revenues decrease for each resource type in Cases when payments by load are lower (i.e., the Extended Case). However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency, fuel costs and fuel inventory.

Table 26. Average Net Revenues by Resource Type, Winter Central Frequent Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$38,260	$42,210	$3,950
Dual Fuel - CT	$19,548	$30,244	$10,696
Gas Only - CC	$2,231	$3,273	$1,042
Gas Only - CT	$188	$6,107	$5,919
Gas with LNG under ESI	$13,244	$17,416	$4,172
Oil Only - Steam	$10,174	$14,839	$4,665
Oil Only - CT	$2,435	$8,664	$6,228
Coal	$161,951	$165,483	$3,532
Biomass/Refuse	$229,680	$233,026	$3,346
Fuel Cell	$144,742	$147,890	$3,148
Hydro	$95,745	$100,113	$4,368
Nuclear	$268,661	$272,340	$3,679
Solar	$12,222	$12,239	$17
Wind	$94,529	$95,750	$1,221
Offshore Wind	$138,457	$139,966	$1,509

Table 27. Average Net Revenues by Resource Type, Winter Central Extended Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$20,343	$18,298	($2,046)
Dual Fuel - CT	$13,555	$17,046	$3,491
Gas Only - CC	$6,257	$6,750	$494
Gas Only - CT	$0	$2,813	$2,813
Gas with LNG under ESI	$27,299	$26,965	($334)
Oil Only - Steam	$9,748	$5,283	($4,465)
Oil Only - CT	$3,964	$2,360	($1,604)
Coal	$87,783	$82,474	($5,309)
Biomass/Refuse	$148,791	$143,160	($5,632)
Fuel Cell	$76,588	$71,216	($5,373)
Hydro	$66,814	$67,193	$380
Nuclear	$175,308	$169,440	($5,869)
Solar	$9,944	$9,638	($307)
Wind	$68,604	$64,961	($3,644)
Offshore Wind	$93,357	$89,652	($3,705)

Table 28. Average Net Revenues by Resource Type, Winter Central Infrequent Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$6,594	$7,102	$508
Dual Fuel - CT	$6,070	$7,697	$1,627
Gas Only - CC	$7,702	$8,355	$653
Gas Only - CT	$21	$1,573	$1,552
Gas with LNG under ESI	$27,668	$7,348	($20,320)
Oil Only - Steam	$310	($973)	($1,283)
Oil Only - CT	$1	$752	$751
Coal	$34,234	$35,184	$950
Biomass/Refuse	$96,287	$97,453	$1,165
Fuel Cell	$27,541	$28,023	$482
Hydro	$39,673	$41,168	$1,495
Nuclear	$115,752	$117,111	$1,359
Solar	$7,707	$7,761	$54
Wind	$38,893	$39,309	$415
Offshore Wind	$60,976	$61,702	$726

7. *Operational Impacts and Reliability*

The proposed ESI market rules are expected to improve system reliability by procuring day-ahead services that ensure the system has energy supplies available to meet real-time operational needs. As described in **Section I.B**,[56] each of the ESI option products is designed to ensure that energy supplies are available to fill potential gaps in energy supplies and improve the region's energy security. More specifically, these option products will help to ensure that forecast loads can be met in real-time (EIR), operating reserves have sufficient energy supplies to respond to system contingencies (GCR), and energy supplies are available to replace the operating reserves when they are deployed to respond to extended, large contingencies (RER). Procuring these services will create incentives for resources to take actions along short-term and long-term horizons to improve their ability to provide real-time energy supplies.

As noted previously, our production cost model is not designed to provide a thorough or complete analysis of the impact of ESI on potential reliability outcomes. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability and security outcomes. The model does not consider a complex set of contingency events, does not account for transmission topology, and does not consider plant commitment, dispatch and other intertemporal limits to plant operations (e.g., minimum run time and minimum down time). Due to the combined impact of these factors, we would expect our model to understate potential reliability risks associated with any market simulation under both the CMR and ESI runs. As a result, to the extent that the incremental energy inventories that ESI may incent improve the region's reliability, these benefits are likely to be understated.

Nonetheless, we analyze multiple metrics that can provide information consistent with reliability improvements. These metrics include traditional reliability metrics associated with resource availability. But, they also include a broader set of metrics related to fuel use and fuel inventory, as these are related to ESI's objectives of securing energy supplies. In particular, we evaluate:

- ***Operating reserve shortages:*** Hours of 10- or 30-minute operating reserve shortage.
- ***Natural gas consumption when natural gas supply is tight:*** Change in natural gas consumption during periods when the natural gas supply is tight, as reflected by high prices (greater than $16 per MMBtu). This metric provides information on the extent to which ESI relaxes pressure on fuel supply systems during stressed conditions when gas prices are high. This quantity is estimated net of natural gas supply from forward LNG contracts.
- ***Minimum and average daily quantity of deliverable energy from oil-fired units.*** The quantity of energy (MWh) available from oil-only and dual-fuel resources (running on oil) given actual fuel inventory is calculated for each day. We calculate the minimum and average quantity of daily energy available over the course of the entire winter. These metrics provide information on the ability of oil-fired resources to provide energy and support reliable system operations across the winter. **Figure 27** to **Figure 29** show the daily level of these metrics for the Frequent, Extended and Infrequent Cases, respectively.

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[56] How these products align with the region's reliability standards is also discussed in further detail in: Mark Karl and Peter Brandien, Letter to NEPOOL Markets Committee, December 4, 2019. https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_i_memo_re_how_market_improvements_address_fuel_security.pdf

- ***Maximum 3-day drop in energy inventory.*** The largest drop in energy inventory during a 3-day period over the course of the winter. This metric provides information on how aggressively fuel inventories are being drawn down in response to stressed market conditions. In the past, rapid draw down of energy inventories has caused reliability concerns for the region.

Figure 27. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Frequent Case (MWh)

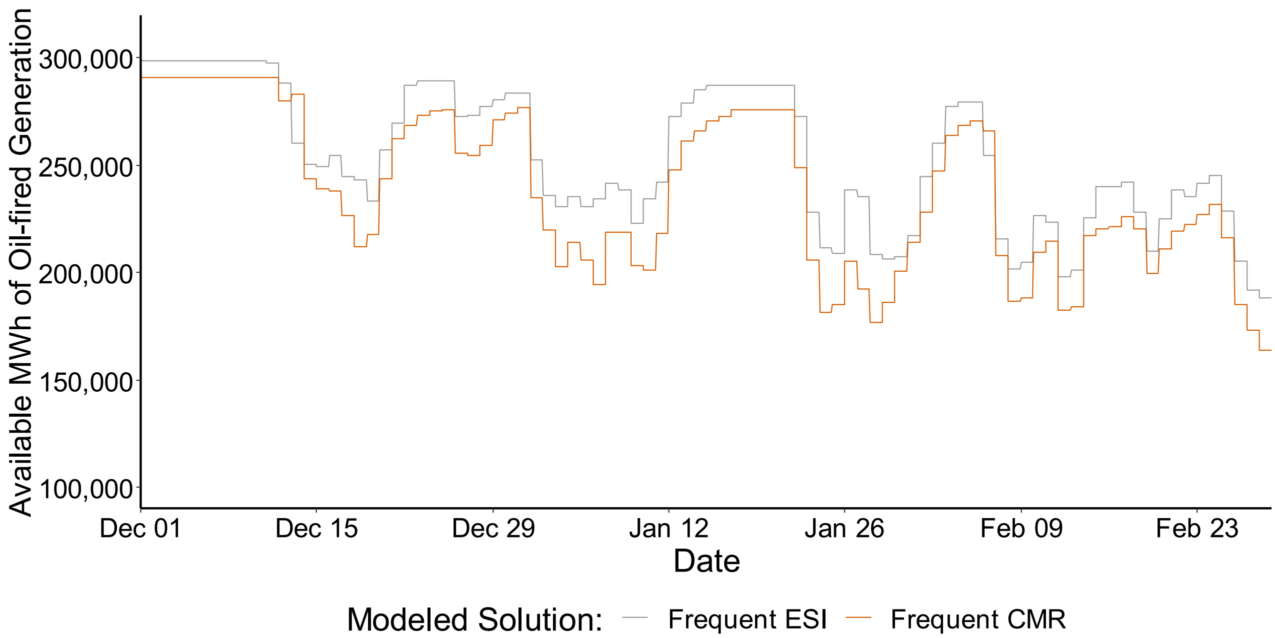

Figure 28. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Extended Case (MWh)

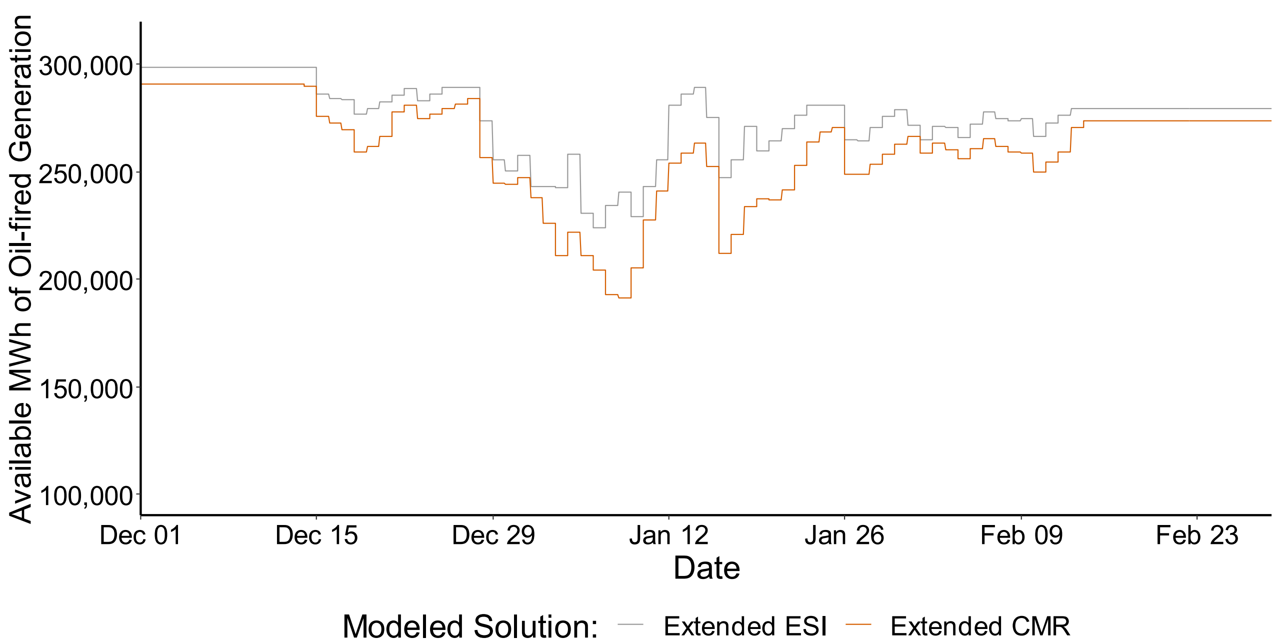

Figure 29. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Infrequent Case (MWh)

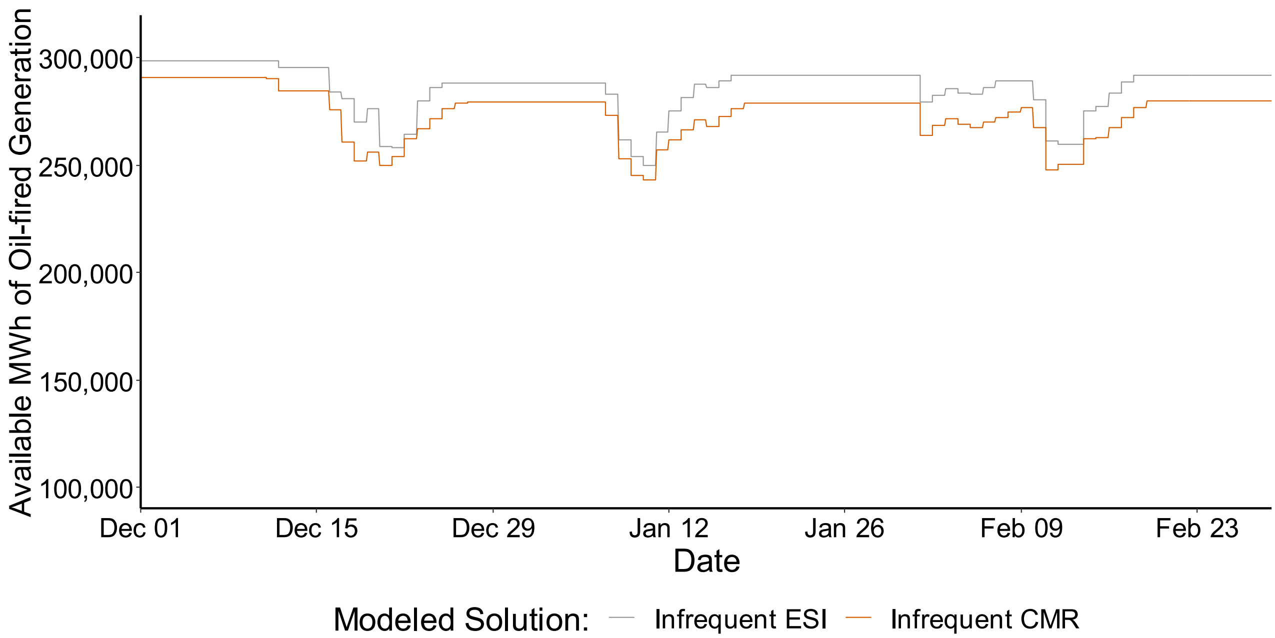

Table 29 provides the *change* in operational metrics with ESI compared to CMR Cases.[57] In general, these operational metrics indicate that there is less stress on physical energy systems and increased availability of energy inventory under ESI as compared to CMR. These results are consistent with improvements in reliability and improved energy security under ESI as compared to current market rules. For example, under ESI, natural gas consumption during stressed periods (with high natural gas prices) is reduced by 2.9 million MMBtu and 0.9 million MMBtu in the Frequent and Extended Cases, respectively. Similarly, the minimum and average quantity of oil inventory increases with ESI as compared to CMR across all Cases, with the increase in the average daily energy associated with inventoried oil ranging from 11.7 to 15.2 GWh. For the particular deterministic scenarios analyzed in the Central Case, there are no operating reserve shortages in either the CMR or ESI cases. However, as discussed above, our analysis is not designed to provide a thorough or complete analysis of system reliability and may make assumptions that lead it to overstate system reliability. It is notable that Scenarios considering supply contingencies, addressed in **Section IV.C.1.b**, find some operating resource shortages during certain contingencies. Thus, we caution against drawing inferences about the current or present reliability of the system from our results.

In addition, operational metrics tend to show that ESI provides a greater reliability benefit under stressed market conditions (Frequent and Extended Cases) as compared to unstressed market conditions (Infrequent Case). For example, the increase in daily oil-fired generation available due to ESI is greater in the Frequent

57 The levels for these operational metrics in the ESI and CMR cases are provided in the appendix.

and Extended Cases than in the Infrequent Case, particularly when comparing the minimum quantities of energy available over the winter. The same pattern is observed for the 3-day decline in oil inventories.

Table 29. Change in Operational Metrics, ESI v. CMR, Winter Central Case

Case	Operating Reserve Shortages (Hours)	Natural Gas Used in Generation When NG Economically Binding (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline
Frequent Case	0	(2,897,177)	24,512	15,204	(16,413)
Extended Case	0	(943,020)	32,663	14,022	(7,527)
Infrequent Case	0	0	6,753	11,656	(77)

B. Non-Winter Cases

To assess the impacts of ESI in non-winter months, we evaluate two non-winter Cases, a Moderate Case, reflecting moderate or typical market conditions, and a Severe Case, reflecting severe conditions with higher energy loads. Below, we summarize the estimated impacts on prices and compensation to energy supply, energy and option supply awards, customer payments and resource net revenues.

ESI would be expected to lead to an increase in payments by load during non-winter months. Estimated increases in payments are $89 million (3.6%) and $125 million (4.6%) in the Moderate and Severe Cases, respectively, over the nine-month non-winter period.

In our quantitative analysis of non-winter month impacts, we assume that market participant decisions related to real-time resource operations are the same in both the CMR and ESI cases. Thus, while we expect that ESI's incentives may have some effect on the decisions market participants make that affect their ability to reliably deliver energy supplies in real-time, such effects would be difficult to quantify, particularly for the market conditions assumed in our Central Case.

In addition, because the fuel supply during non-winter months does not face the constraints experienced in winter months, comparable shifts in fuel consumption between CMR and ESI cases do not occur in the non-winter month analyses. Given these factors, our quantitative analysis of real-time market outcomes produces the same outcomes in the CMR and ESI cases.[58] As a result, impacts that are based on changes in real-time outcomes (e.g., production costs and operational benefits) are not assessed because our analysis would not quantify any change that may occur.

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58 This outcome reflects a number of factors, including the fact that our model does not include unit commitment and many inter-temporal and operational constraints to unit operations. As a result, any changes associated with day-ahead clearing due to ESI do not affect real-time dispatch in our model, although such differences would be expected to arise in actual market operations.

While we do not quantify these effects, we expect that ESI would create reliability benefits and reductions in production costs during non-winter months, as well as during winter months.[59] Production costs would be expected to fall through the more orderly procurement of reserves in the day-ahead market. Reliability benefits would be expected from increasing the supply of energy in real-time to mitigate unanticipated contingencies or deviations between forecast and realized load. Such reliability benefits are most likely to occur under circumstances when large, sustained system contingencies occur, leaving the system vulnerable and straining the system's ability to recover 10- and 30-minute reserves consistent with NERC/NPCC standards. Further, changes in the composition of electric and natural gas infrastructure in the New England (and surrounding) region, including changes in resource mix in response to state incentives for renewable resources, could create market conditions in which energy security concerns become more pressing in non-winter months than at present. Under these circumstances, we would expect the reliability benefits that ESI would provide during non-winter months to increase beyond its ability to address unanticipated contingencies.

1. *Compensation to Energy Supply*

Table 30 provides the change in payments to energy for the three Central Cases. Changes reflect both the impact on LMPs and the additional FER payments. Across the two cases, DA LMPs are reduced by $0.18 per MWh in the Moderate Case and $0.23 per MWh in the Severe Case. These LMP changes are driven by the changes in energy that clears the day-ahead market, which occur because under ESI, the day-ahead market includes the FER. But, suppliers of physical DA energy receive FER payments, in addition to the LMP, with average FER payments of $0.76 per MWh in the Moderate Case and $1.12 per MWh in the Severe Case. Accounting for the net effect of these two components, total payments to DA energy increase in the two cases by $0.58 per MWh (Moderate Case) and $0.89 per MWh (Severe Case).

Table 30. Average DA Payments to Generators, Non-Winter Central Case

CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
Case	Day-Ahead LMP [A]	Day-Ahead LMP [B]	FER [C]	Day-Ahead LMP + FER [D]=[B]+[C]	Real-Time LMP [E]	Day-Ahead LMP [B]-[A]	Day-Ahead LMP + FER [D]-[A]
Moderate Case	$27.90	$27.72	$0.76	$28.48	$28.35	($0.18)	$0.58
Severe Case	$29.81	$29.58	$1.12	$30.71	$30.65	($0.23)	$0.89

2. *Prices for ESI Ancillary Services*

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 31** reports average award prices for these products for the non-winter Cases. These prices are weighted averages, reflecting the quantity of each product procured in each hour.

[59] Both production costs and the operational metrics we measure to capture reliability benefits are based on real-time market outcomes. Because our analysis is not designed to capture changes in real-time dispatch between the CMR and ESI cases in non-winter months (as described above), our quantitative analysis would also not capture changes in production costs or these operational metrics.

Average ESI product prices are relatively consistent between Cases for GCR10, GCR30 and RER, ranging from $6.35 to $7.81 per MWh. For these products, the quantities are assumed to be the same in all hours, although in fact these quantities may differ from hour to hour.

Weighted average prices for EIR are higher than for the other ESI products, at $12.72 per MWh in the Moderate Case and $31.31 per MWh in the Severe Case. This occurs because the weights – EIR quantity – vary by hour and EIR prices tend to be higher in hours when EIR quantities are higher. Thus, even though prices in each hour for ESI products tend to be relatively similar, the weighted average EIR price is greater than for the other ESI products.

Table 31. Average DA Energy Option Clearing Prices, Non-Winter Central Case
($ per MWh)

Case	EIR/FER	GCR10	GCR30	RER
Moderate Case	$12.72	$6.36	$6.35	$6.35
Severe Case	$31.31	$7.81	$7.80	$7.80

3. *Supply of Energy and DA Energy Options*

Consistent with the winter Central Cases, introduction of the FER requirements causes the market to clear additional DA energy when there would otherwise be a gap between cleared energy supply and the load forecast. **Table 32** quantifies these adjustments, showing the changes in DA energy by resource type between CMR and ESI. Under CMR, the total energy clearing in the day-ahead market ranges between 88.0 and 90.2 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges between 89.6 and 91.5 TWh (column [B]). Thus, DA energy supply increases by 1.4 and 1.6 TWh, an increase of 1.5% and 1.8%, respectively, compared to current market rules (column [D]). These increases in DA energy happen as a consequence of the co-optimization of DA energy and EIR. While DA energy increases, there remains a gap between cleared DA energy and the forecast load in some hours. However, this gap is small, only 7.0 and 10.8 GWh, less than 0.1% of total load in both Cases.

Table 32. Changes in Cleared DA Energy, Non-Winter Central Case
CMR vs ESI (MWh)

	CMR	ESI		Difference	Real-Time Comparison	
Case	Day-Ahead Energy [A]	Day-Ahead Energy [B]	Cleared EIR [C]	Day-Ahead Energy [D] = [B] - [A]	Real-Time Demand	Energy + EIR [E] = [B] + [C]
Moderate Case	87,970,357	89,587,167	6,983	1,616,810	88,287,439	89,594,149
Severe Case	90,175,883	91,534,279	10,848	1,358,396	90,053,188	91,545,127

While overall DA energy supplies, including DA energy and DA energy options, increase in aggregate in both non-winter Cases, these impacts vary across resource types. **Table 33** and **Table 34** shows the impact of ESI on the products supplied in the day-ahead markets across resource types. While there are differences, the direction and magnitude of these impacts is very similar between the two non-winter Cases.

Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. Nearly all resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), and smaller amounts for other resource types. DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only). These supply patterns are similar to the patterns observed in the winter month Cases.

Table 33. Energy and DA Energy Options by Resource Type, Non-Winter Central Moderate Case
CMR vs ESI (MWh)

Resource Type	Summer SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	11	32	0	21
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,249,546	4,261,671	0	12,125
Coal	531	167,617	177,373	23,906	9,755
Dual Fuel - CC	5,884	16,409,650	17,270,052	1,109,309	860,402
Dual Fuel - GT	1,237	777,989	776,349	4,203,326	(1,640)
Fuel Cell	21	4,929	5,537	0	608
Gas - CC	7,411	21,220,038	21,872,957	1,446,084	652,920
Gas - GT	364	10,993	7,395	1,270,802	(3,598)
Hydro	1,987	4,464,248	4,464,248	3,103,966	0
Imports	2,850	14,979,450	15,062,719	0	83,269
Nuclear	3,344	19,520,806	19,520,806	0	0
Offshore Wind	800	2,398,673	2,398,673	0	0
Oil Only - Steam	3,698	114	2,527	2,527	2,413
Oil Only - CT	2,114	0	0	5,063,873	0
Pumped Storage	1,778	1,882,553	1,882,553	7,542,569	0
Solar	1,671	1,968,609	1,968,609	0	0
Wind	1,401	2,472,822	2,472,822	0	0

Table 34. Energy and DA Energy Options by Resource Type, Non-Winter Central Severe Case
CMR vs ESI (MWh)

Resource Type	Summer SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	51	168	0	117
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,295,501	4,296,836	0	1,336
Coal	531	252,245	272,980	38,705	20,735
Dual Fuel - CC	5,884	17,699,486	18,103,706	1,166,872	404,220
Dual Fuel - GT	1,237	792,172	797,347	4,154,426	5,175
Fuel Cell	21	6,460	7,478	0	1,018
Gas - CC	7,411	22,111,781	22,998,479	1,404,690	886,699
Gas - GT	364	25,141	28,663	1,256,090	3,522
Hydro	1,987	4,085,436	4,085,436	3,302,992	0
Imports	2,850	15,341,837	15,360,004	0	18,168
Nuclear	3,344	19,528,105	19,528,105	0	0
Offshore Wind	800	2,398,596	2,398,596	0	0
Oil Only - Steam	3,698	1,418	17,619	17,619	16,202
Oil Only - CT	2,114	0	37	2,970,196	37
Pumped Storage	1,778	1,882,553	1,882,553	9,457,666	0
Solar	1,671	1,863,549	1,863,549	0	0
Wind	1,401	2,448,824	2,448,824	0	0

4. *Impact of Customer Payments*

Total change in customer payments due to the ESI proposal will reflect a combination of factors: total LMP payments through day-ahead and real-time markets; compensation for meeting the FER; and new payments made in the day-ahead market for DA energy options. **Table 35** summarizes the net impact of these three components on total customer payments.

Total payments increase by $89 million in the Moderate Case, and $125 million in the Severe Case. Total payments for energy – LMPs and FER payments – increase in both cases, by $50 million and $78 million in the Moderate and Severe Cases, respectively (equal to the sum of the difference in energy and FER payments under ESI). Similarly, net payments for ESI products are $38 million and $47 million, respectively. In total, these changes represent a 3.6% and 4.6% increase in payments for the Moderate and Severe Cases, respectively.

Table 35. Non-Winter Total Payments, Non-Winter Central Case ($ Million)

		Moderate Case				Severe Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$2,473	$2,455	-$18	-0.7%	$2,697	$2,672	-$25	-0.9%
DA Energy Option									
DA Option Payment			$151				$186		
EIR			$0				$0		
RER			$50				$62		
GCR10			$67				$83		
GCR30			$34				$41		
RT Option Settlement			-$113				-$139		
Net DA Ancillary	[B]		$38				$47		
FER Payments	[C]		$68				$103		
Total Payments	[A+B+C]	$2,473	$2,562	$89	3.6%	$2,697	$2,822	$125	4.6%

In the context of all payments made by consumers for wholesale electric power services, these changes in payments are modest.[60] **Table 36** shows the total annual change in customer payments due to ESI for each of the possible combinations of winter and non-winter Central Cases evaluated. The annual changes in payments range from $20 million to $257 million, which, when compared to total payments of $12.24 billion in 2018, represents a 0.2% to 2.1% change in total payments.

Table 36. ESI Payment Impacts Relative to Total Customer Payments in ISO-NE Markets

Non-Winter Case		**Severe**			**Moderate**	
Winter Case	**Frequent**	**Extended**	**Infrequent**	**Frequent**	**Extended**	**Infrequent**
Incremental Payments from ESI	$257	$56	$160	$221	$20	$123
Percent of Total	2.1%	0.5%	1.3%	1.8%	0.2%	1.0%
Total Payments (2018)	$12,240	$12,240	$12,240	$12,240	$12,240	$12,240

5. Resource Net Revenue

As with the winter analysis, the impact of ESI on the net revenues earned by resources in non-winter months would depend on a combination of factors. In aggregate, changes in payments by load would lead to corresponding changes in revenues to generators. Thus, when payments to load are expected to increase as occurs in both non-winter Cases, this would be expected to lead to a corresponding increase in revenues to resource owners.

Table 37 and **Table 38** provide the average net revenues by resource type for the Moderate and Severe Cases, respectively. With a few exceptions, net revenues increase in both Cases. However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency and the ability to provide ESI ancillary services.

60 Relative to all payments made by consumers for retail service, these payments would be smaller than the figures represented in **Table 35**.

Table 37. Average Net Revenues by Resource Type, Non-Winter Central Moderate Case ($ per MW – 9-Non-Winter Months)

	Net Revenue ($/MW Capacity)		
	CMR	ESI	Change
Resource Type:	[A]	[B]	[C] = [B] - [A]
Dual Fuel - CC	$7,914	$9,899	$1,985
Dual Fuel - GT	$6,782	$12,721	$5,940
Gas Only - CC	$8,265	$10,323	$2,058
Gas Only - GT	$562	$6,823	$6,261
Oil Only - Steam	$23	$47	$24
Oil Only - CT	$353	$2,502	$2,149
Coal	$5,353	$6,296	$943
Biomass/Refuse	$134,779	$137,212	$2,433
Fuel Cell	$3,463	$3,616	$153
Hydro	$67,892	$71,579	$3,686
Nuclear	$158,399	$161,162	$2,764
Solar	$31,080	$31,482	$402
Wind	$49,772	$50,583	$811
Offshore Wind	$81,640	$82,839	$1,198

Table 38. Average Net Revenues by Resource Type, Non-Winter Central Severe Case ($ per MW – 9-Non-Winter Months)

	Net Revenue ($/MW Capacity)		
	CMR	ESI	Change
Resource Type:	[A]	[B]	[C] = [B] - [A]
Dual Fuel - CC	$9,872	$13,158	$3,286
Dual Fuel - GT	$8,380	$15,971	$7,591
Gas Only - CC	$10,264	$13,555	$3,291
Gas Only - GT	$1,382	$9,027	$7,645
Oil Only - Steam	$192	$241	$50
Oil Only - CT	$606	($83)	($689)
Coal	$9,411	$9,394	($18)
Biomass/Refuse	$145,754	$149,222	$3,468
Fuel Cell	$6,964	$7,457	$493
Hydro	$69,230	$74,225	$4,995
Nuclear	$170,861	$174,801	$3,940
Solar	$32,442	$33,300	$858
Wind	$53,491	$54,569	$1,078
Offshore Wind	$88,152	$89,830	$1,678

C. Scenario Analysis

As described earlier, the Central Cases make specific assumptions about the future resource mixes and fuel levels, and consider various load and weather conditions based on historic data. These cases are intended to represent potential future scenarios for 2025/26 in which system resources and market conditions would remain (relatively) unchanged from today. While these Central Cases are reasonably plausible, there is substantial uncertainty about how market and system conditions will change between now and the time when ESI would come into effect.

We have therefore modeled a number of additional Scenarios. These Scenarios generally start with the winter Central Case analysis and change one (or several) key assumptions, but otherwise keep all assumptions the same. For each Scenario, we evaluate the same Frequent, Extended and Infrequent Cases that are evaluated in the Central Case, thus assessing how the Scenario results may be impacted by load and weather conditions.

Several different types of scenarios are evaluated. ***First***, we consider ESI's impacts under ***different assumptions about future market conditions***, as described in **Table 39**. These Scenarios will help illustrate how ESI would be expected to affect market outcomes under a range of market and system conditions, including those with more and less frequent stressed system conditions, and those in which energy costs are higher than is assumed in the Central Cases. Particular future assumptions tested include changes to the region's mix of electric power resources, the infrastructure that delivers fuel to the region, and load growth.

Table 39. Winter Scenarios Evaluating Changes in Market or System Conditions

No Fuel-Related Market Response	
Risk Premium x1.25	"Central Case" with DA energy option offers calculating using risk premia set at 125% of Central Case levels.
Supply Shocks	Unexpected real-time outages, experienced during coldest portion of historic winter.
Shock HQ 1 Day	Supply shock (outage) fo 1,364 MW is modeled in real-time market, but not modeled in day-ahead market. - Frequent Stressed Conditions: January 3, 2014 (average temperature 4.77 F); - Extended Stressed Conditions: January 1, 2018 (average temperature 2.72 F); - Infrequent Stressed Conditions: December 16, 2016 (average temperature 11.64 F).
Shock HQ 5 Days	Supply shock of 1,364 MW is modeled in Day-1 real-time market, but not expected in Day 1 day-ahead market. Resource is expected out day-ahead in remaining days (Days 2-5). - Frequent Stressed Conditions: January 21-25, 2014 (average temperature 12.83 F); - Extended Stressed Conditions: December 28, 2017 - January 1 2018 (average temperature 5.68 F); - Infrequent Stressed Conditions: January 6-10, 2016 (average temperature 19.07 F).
High LNG Supply	Assume additional LNG availability of 0.4 Bcf/day to both ESI and CMR cases (all winter severities). Under ESI, assume an incremental 0.4 Bcf/day available for LNG forward contracts, for a total of 0.52 Bcf/day available for forward contracts.
Low LNG Supply	Assume reduced LNG availability of 0.12 Bcf/day in both ESI and CMR cases for all winter severities (corresponding to LNG forward contract).
High Load	Load is increased by 5%, with no other modeling changes.
Oil Retirements	For oil retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~1,000 MW of oil resources retired.
With Renewable Replacement	3,824 MW nameplate (1,400 MW derated) of new offshore wind, and 1,200 MW of new hydro imports.
Nuclear Retirements	For nuclear retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~3,500 MW of nuclear resources retired.
With Renewable Replacement	8,824 MW nameplate (3,000 MW derated) of new offshore wind, 5,333 MW nameplate (800 MW derated) of new onshore wind, and 1,200 MW of new hydro imports.
With Fuel-Related Market Response	
Oil Retirements	For oil retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~1,000 MW of oil resources retired.
With Gas Replacement	2,500 MW of new natural gas CC resources, none with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	2,500 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
Nuclear Retirements	For nuclear retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~3,500 MW of nuclear resources retired.
With Gas Replacement	5,000 MW of new natural gas CC resources, none with dual-fuel capability and 0.7 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	5,000 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.7 Bcf/day of additional NG supply

Second, we consider the impacts of ***different ESI designs***. **Table 40** describes these Alternative Proposals, which include designs that change the quantity of procured ESI products (in some cases, reducing them to 0 MWh), and designs with an energy option strike price that differs from the ISO-NE proposal. These Alternate Proposals are provided in response to feedback and requests during the stakeholder process. Assessing the market and reliability impacts under these alternate proposals will provide information about market and operational outcomes for these alternate designs, which have been discussed with stakeholders.

Table 40. Winter Scenarios Evaluating Alternate ESI Proposals

No Fuel-Related Market Response	
RER Plus	"Central Case" with RER requirement set to 150% of Central Case level (1,800 MW).
Strike Plus $10	"Central Case" with DA energy option strike price = Central Case strike price + $10 in all hours; adjustment affects all calculations, incuding risk premia.
With Fuel-Related Market Response	
No EIR/RER	"Central Case" with no RER nor EIR requirement. Under ESI, there is no incremental fuel relative to amounts assumed under CMR.
No RER	"Central Case" with no RER requirement. Under ESI, incremental fuel (i.e., relative to CMR) is assumed to be one-half of the incremental fuel amounts assumed in the Central Case.

Third, we consider one Scenario in which the ***ESI design is unchanged from the ISO-NE proposal, but causes no change in the fuel inventory and refueling decisions of market participants***. We do not evaluate this Scenario because we expect there to be no change in fuel inventories if ESI were adopted (recall, **Section IV.1** found that ESI generally increases the incentive to hold fuel relative to current market rules). Rather, this Scenario provides information on the impact of the ESI proposal, apart from the impact of the incremental fuel inventory due to the new incentives created by ESI.

Fourth, we consider two ***non-winter Scenarios***, both involving different ESI design elements. One Scenario assumes no RER product in non-winter months (analogous to the “No RER” winter Scenario), while the second Scenario assumes a strike price set $10 per MWh above the expected RT LMP (analogous to the “Strike Plus $10” winter Scenario).

Table 41. Non-Winter Scenarios

No Fuel-Related Market Response	
Strike Plus $10	"Central Case" with DA energy option strike price = Central Case strike price + $10 in all hours; adjustment affects all calculations, incuding risk premia.
With Fuel-Related Market Response	
No RER	"Central Case" with no RER requirement. Under ESI, incremental fuel (i.e., relative to CMR) is assumed to be one-half of the incremental fuel amounts assumed in the Central Case.

While our model captures many of the market adjustments that occur with new Scenario assumptions, it does not endogenously capture all effects. In particular, the model does not endogenously adjust aggregate fuel supplies or resource-level fuel inventory decisions for changes in market design or market conditions.[61] In general, however, we would expect market responses to depend on underlying assumptions about market tightness and market design. For example, if changes to energy supply or demand occurred that reduced the region’s energy security (where these changes could be caused by resource retirements, changes in load, or

[61] In principle, these adjustments can include market, regulatory and policy responses to market conditions. With regard to regulatory and policy responses, we take no position on the form of any such policy response, but acknowledge that such responses could occur.

other factors), we may also observe potential changes in fuel supply and demand, such as new sources of LNG supplies, new infrastructure (e.g., LDC peak shavers), and new dual fuel capability.

While we expect some degree of market response in many Scenarios, the magnitude of this expected response varies. Thus, for Scenarios in which we expect the market response to be comparatively smaller, we make no additional change from the Central Case (beyond the core change assumed in the Scenario), whereas in Scenarios in which we expect a larger market response, we modify certain assumptions from the Central Case related to fuel.

Table 39 and **Table 40** identify the Scenarios with fuel assumptions that are the same as the Central Case, and the Scenarios with fuel assumptions that differ from the Central Case, respectively. In Scenarios assuming substantial retirements of oil or nuclear resources with replacement by natural gas-fired resources, we assume a market response to these retirements, as the increased dependence on natural gas-fired resources would cause an increase in demand that stimulates greater natural gas supply available to the region. This market response could come in one of many different forms, such as additional natural gas supplies through an LNG terminal, development of new LDC peak-shaving facilities to relieve reliance on the remaining LNG terminals, or additional dual-fuel capability (which would also reduce the dependence on the region's gas infrastructure). In these Scenarios, we assume the incremental fuel supply is present in both the CMR and ESI Cases, as the retirements are also assumed in both cases.

Likewise, several Scenarios assume alternative designs that would be expected to reduce the incentives to retain fuel supplies relative to the ISO's ESI proposal. In some of these Scenarios, we reduce the quantity of incremental fuel in the ESI Case to reflect this impact. In these cases, we keep the assumptions in the CMR Case unchanged, as these Scenarios do not contemplate any changes in underlying market conditions common to both CMR and ESI Cases.

There are many Scenarios that assume no changes in fuel supplies or inventories relative to those assumed under ESI in the winter Central Cases. This does not imply that no such changes would occur, in actuality, but rather that one can reasonably assume that any such changes may be modest. Moreover, although we make best efforts to develop reasonable assumptions about fuel supply or inventory response in each Scenario, these assumptions are not forecasts or precisely estimated adjustments.

Thus, when comparing *between* Scenarios (and between the Central Cases and Scenarios), care should be taken to recognize that the results represent plausible market and operational impacts of the market rule changes, but are not intended to be definitive. Because counterfactual assumptions about fuel availability (market supplies and inventory) and potentially other factors are not carefully calibrated, quantitative comparisons between Scenarios may not provide a balanced "apples-to-apples" comparison. Nonetheless, these Scenarios do help to shed further light on the possible impacts of ESI across various market conditions and design changes, and also help to illustrate the model's sensitivities to key input assumptions.

The results of our Scenario analysis are reported in the body of this report and with additional detail in a supplemental appendix. In the body of this report, we provide the impacts (changes) on prices and payments, and the impacts (changes) on operational metrics indicative of potential reliability benefits.

- For the Scenarios evaluating the ***changes in market or system conditions***, **Table 42** to **Table 44** report the changes in prices (LMPs, ESI prices) and total payments for the Frequent, Extended and Infrequent Cases, respectively, while **Table 45** to **Table 47** provide the changes in operational metrics for the Frequent, Extended and Infrequent Cases, respectively. In each table, the Central Case results are presented for comparison purposes.

- For the Scenarios evaluating the changes in ***ESI market design*** and the Scenario assuming ***no incremental ESI fuel***, **Table 48** to **Table 50** report the changes in prices (LMPs, ESI prices) and total payments for the Frequent, Extended and Infrequent Cases, respectively, while **Table 51** to **Table 53** provide the changes in operational metrics for the Frequent, Extended and Infrequent Cases, respectively. In each table, the Central Case results are presented for comparison purposes.

The supplemental appendix provides these results plus the impacts on shortage hours of day-ahead and real-time ancillary services, as well as the levels for the prices and payments, operational metrics, and shortage hours for both the CMR and ESI Cases.

1. Scenarios Evaluating Changes in Market or System Conditions

a) Risk Premium

The Risk Premium plus 25% Scenario assumes a 25% increase in all risk premiums for DA energy option offers in the ESI run compared to the Central Case estimates. This Scenario provides information on the sensitivity of impacts to the cost of procuring the DA energy options. With the higher risk premiums, total payments increase by $42 million, $29 million and $13 million compared to Central Case payments for the Frequent, Extended and Infrequent Case, respectively. Most of this change in payments is due to the higher net cost of the DA energy options, which increase by $41 million, $25 million and $10 million, respectively, in the Frequent, Extended and Infrequent Cases. By contrast, the net cost for energy (LMPs plus FER payments) remains relatively unchanged.

While this Scenario provides information on the sensitivity of impacts to general (uniform) shifts in the magnitude of the DA energy option offers, it is not intended to represent the potential impacts of the exercise of seller-side market power on market outcomes. Such analysis is outside the scope of this report.

b) Supply Shocks

The supply shock Scenarios assume 1-day and 5-day supply contingencies, in which imports are reduced by 1,364 MW during stressed market conditions. In the first day of both Scenarios, the resource is assumed to be available in the day-ahead market but not in the next day's real-time market. In the scenario with the prolonged 5-day shock, the unavailable resource is also excluded from the day-ahead market in subsequent days. Other than these supply shocks, the Scenarios are otherwise the same as the Central Case.

In the Frequent Case, ESI has a smaller impact on total payments with supply shocks (as compared to the Central Case), suggesting that ESI reduces total payments during supply shocks. With ESI, total payments increase by $123 million for the 1-day shock and $92 million for the 5-day shock, both less than increase in total payments of $132 million in the Central Case with no shocks. Thus, total payments are $9 million and $40 million lower with ESI in place when a 1-day and 5-day shock occur, respectively. These results suggest that ESI can lower total payments during stressed market conditions. The reductions in payments occur because ESI's incentives for energy inventory would be expected to increase inventoried energy supply, which can lower LMPs during tight market conditions including the period where the contingency occurs.

In the Extended and Infrequent Cases, however, ESI does not have a large impacts on total payments during supply shocks. In the Extended Case, ESI reduces payments by $72 million with a 1-day shock and $66 million with a 5-day shock, both similar to the $69 million reduction in payments impacts in the Central Case with no supply shocks. These results suggest that under some system conditions, ESI may have a relatively small impact on total payments during a supply shock, potentially increasing or decreasing payments. Results in the Infrequent Case are similar – ESI increases payments $34 million with a 1-day shock and $36 million with a 5-day shock, similar to the $35 million increase in costs in the Central Case with no shocks.

Detailed analysis of market outcomes illustrates how market responses to a supply contingency may differ under ESI as compared to current market rules. **Figure 30** shows RT LMPs during the supply contingency, while **Figure 31** shows the aggregate fuel oil inventory. With the higher fuel inventory incented by ESI, the market is able to maintain a supply of energy able to meet real-time loads plus reserve requirements. However, absent this incremental fuel from ESI, the system is short of operating reserves in some hours, and high energy and reserve prices reflect each product's relatively scarcity.

Figure 30. Real-Time LMPs during 5-Day Supply Shock, 5-Day Shock Frequent Case
CMR versus ESI

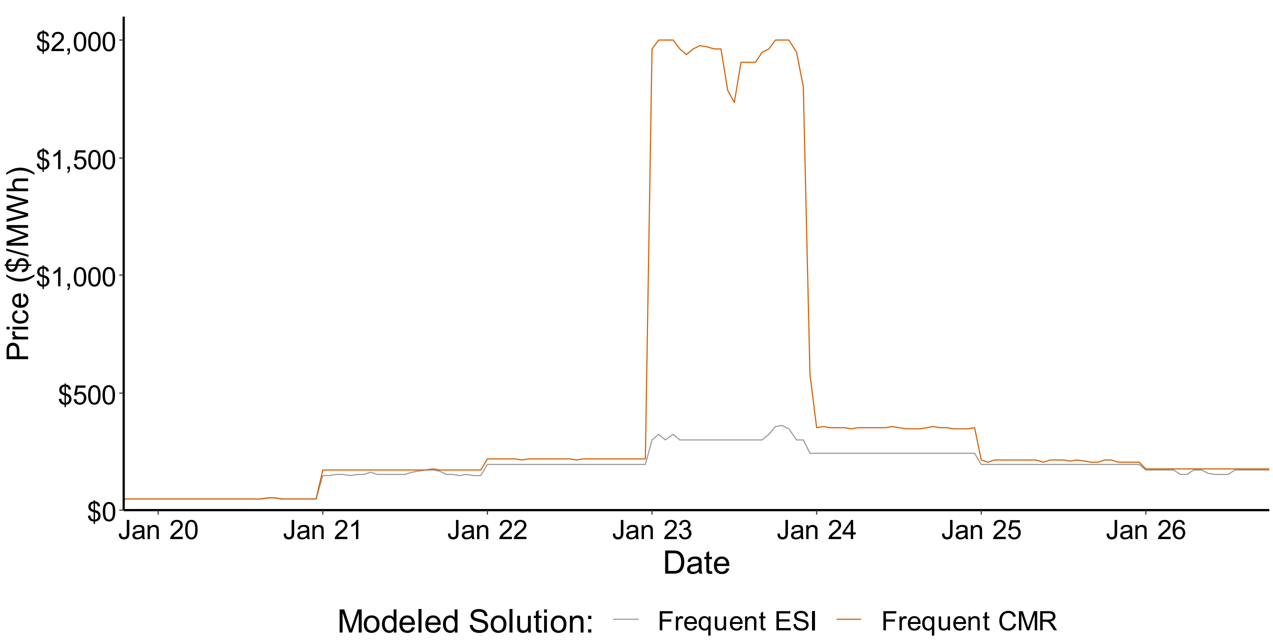
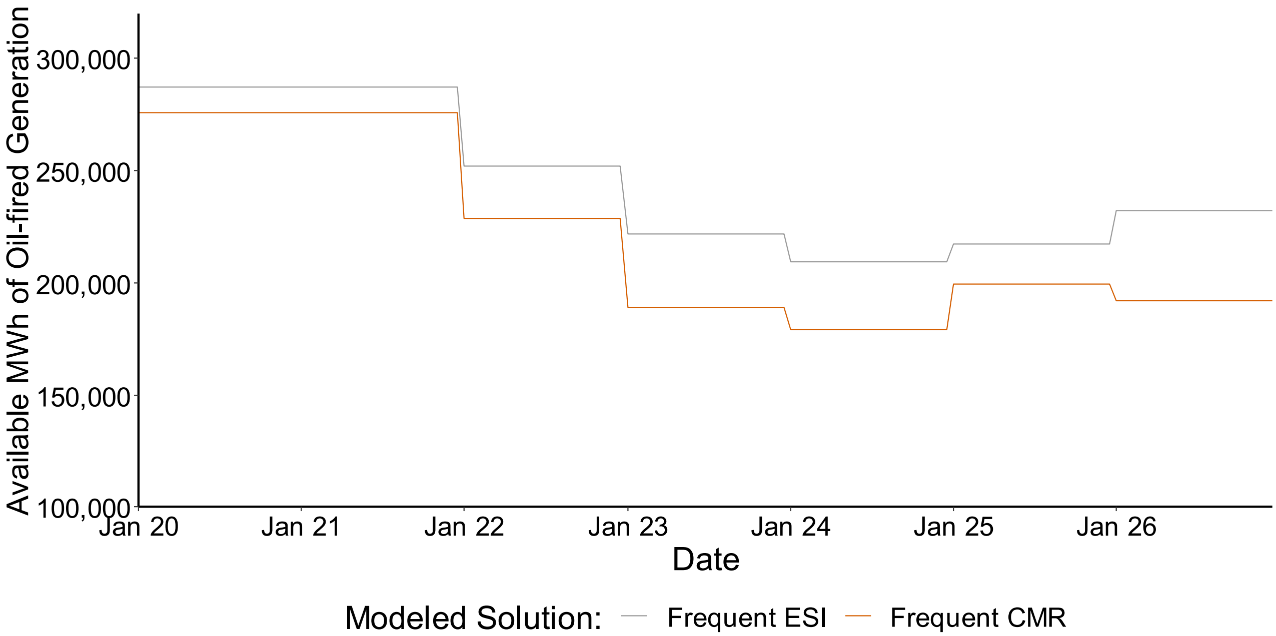


Figure 31. Aggregate Fuel Oil Inventory during 5-Day Supply Shock, 5-Day Shock Frequent Case
CMR versus ESI



Operational metrics generally show larger improvements consistent with reliability benefits compared to the Central Case. In the Frequent Case, ESI avoids three hours of operating reserve shortages that occur under current market rules during the 5-day Supply Shock. Metrics related to natural gas and oil supply generally show larger improvements than the Central Case, suggesting that ESI's reliability impacts may be more significant during periods of system stress due to unexpected contingencies, with improvements being the greatest in the Extended Case.

c) LNG Supply

The LNG Supply Scenarios consider both a higher quantity of daily LNG supply (increased by 0.4 Bcf) and a lower quantity of LNG supply (decreased by 0.12 Bcf) compared to the Central Case. The change in LNG supply is assumed in both the CMR and ESI Cases, and the amount of fuel oil incented by ESI is the same as the Central Case.

Compared to the Central Case, higher LNG supply would tend to reduce ESI's impact on total payments, while lower LNG supply would tend to increase ESI's impact on total payments. These effects are most pronounced during stressed market conditions. With the assumed higher quantity of LNG supply, ESI's impact on total payments is $50 million (Frequent Case) and $108 million (Extended Case) – these are $182 million and $39 million lower than in the Central Cases respectively. By contrast, with lower LNG supplies, total payments in the Frequent Case are $154 million higher with ESI (as compared to CMR) and in the Extended Case are $15 million lower with ESI (compared to CMR) – these values reflect $22 million and $54 million higher costs than in the Central Cases). In unstressed market conditions, the change in LNG supply leads to no meaningful change in payment impacts compared to the Central Case.

d) High Load

The High Load Scenario assumes higher load than is assumed in the Central Cases, with no adjustments to capacity or available energy inventory. With high loads, ESI is estimated to reduce total payments by $322 million and $256 million in the Frequent and Extended Cases, respectively. In both of these stressed conditions cases, ESI's impacts are substantially different than the Central Case, causing large reductions in total payments relative to current market rules. In the Infrequent Case, ESI is estimated to increase payments by $35 million, which is very similar to the Central Case.

The reductions in payments in the stressed conditions cases are driven by the reduction in DA LMPs ($23.92 per MWh and $14.33 per MWh in the Frequent and Extended Cases, respectively) that occur because of the incremental energy inventory incented by ESI. Prices for FER and DA energy options are also larger than in the Central Case. However, the LMP reductions are sufficiently large to offset payment for these ancillary services.

ESI produces operational benefits, particularly under the Frequent and Extended stressed conditions Cases. These impacts vary in magnitude from the Central Case, and are larger in many but not all cases.

e) Retirements

Multiple retirement Scenarios are evaluated. We consider retirement of a set of at-risk oil resources (approximately 1,000 MW) and both remaining nuclear plants (Millbrook and Seabrook, approximately 3,500 MW). For both sets of assumed retirements, we run three distinct Scenarios with retired resources replaced by three different types of new resources: (i) renewable resources, (ii) all gas-only combined cycle resources, or (iii) a mix of gas-only and dual fuel combined cycle resources. Thus, in total, we evaluate six retirement Scenarios (two sets of retirements and three sets of replacement resources for each retirement).

In these retirement Scenarios, we consider whether the retirements would likely prompt a market response in the fuels market, given the potential change in fuel demand from the electricity sector. When retirements are replaced by renewables, we do not assume any market response, as the renewables are not likely to increase fuel demand. In the other Scenarios, the replacement of oil or nuclear plants with resources relying on natural gas will tend to increase demand for natural gas. We assume a corresponding market response that increases the potential supply of natural gas to the electricity sector under both the CMR and ESI runs. We do not identify the source of this supply, which, in principle, could come from LNG supplies (e.g., through the Northeast Gateway buoy), expanded dual fuel capacity, additional LDC "peak shaving" infrastructure (i.e., satellite LNG tanks), and/or other sources. The quantity of incremental fuel we assume reflects an evaluation of the change in LMPs with different levels of incremental natural gas, under the premise that these price signals would drive demand for increased supplies. In the oil retirement cases, we assume an additional 0.3 Bcf of fuel is available each day, while in the nuclear cases we assume an additional 0.7 Bcf. While we adjust the assumptions about aggregate fuel supply, we do not adjust assumptions about the response of market participants to ESI incentives via the procurement of additional oil.

When renewables replace retired resources, the impact of ESI on total payments is ambiguous, increasing payments in some cases and decreasing it in others, compared to the Central Case. At the extremes, ESI's impact on total payments is $50 million higher than the Central Case in one case (Frequent, nuclear retirements replaced by renewables), and $103 million lower than the Central Case in another (Extended, nuclear retirements replaced by renewables). However, compared to the Central Case, renewable replacements generally lead to smaller LMPs reductions (due to ESI) and larger net costs of DA energy options. For example, in the Extended Case, the reduction in average energy costs (due to ESI) is $6.43 per MWh in the Central Case compared to $2.66 per MWh when nuclear resources are replaced by renewables. But, net payments for DA energy options fall from $32 million in the Central Case to $20 million and $21 million for the oil and nuclear retirements, respectively.

When gas-only or a mix of gas-only and dual fuel replace the retired resources, the impact of ESI on payments is very large in magnitude compared to impacts in the Central Case, though in some cases the costs increase whereas in others they decrease. For example, while impacts vary from an increase of $132 million to a decrease of $69 million in the Central Case, ESI impacts vary from an increase of $531 million to a decrease of $193 million with gas/dual fuel replacements for retired resources. This difference in the magnitude of these impacts reflects the sensitivity of the market outcomes as the region increases its reliance on natural gas resources.

While the magnitude of the impacts is greater across these retirement Scenarios, the direction of these impacts differs across stressed cases. In the Frequent Case, the retirement scenario magnifies the increase in cost compared to the Central Case, with ESI impacts rising as high as $531 million ($399 million greater than in the Central Case). However, in the Extended Case, the retirement scenarios magnifies the decrease in total payments caused by ESI compared to the Central Case, with payments decreasing by as much as $193 million ($124 million lower than in the Central Case).

In all Scenarios, the incremental inventoried energy incented by ESI reduces LMPs, but net payments for energy increase in some cases (for example, all Frequent Cases) and decease in other cases (for example, 3 of 4 Extended Cases). Net payments for DA energy options range from $33 million to $119 million across stressed Cases.

Table 42. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Frequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
Risk Premium x1.25	($5.52)	$7.80	$32.33	$67	$107	$174
Shock HQ 1 Day	($5.62)	$7.78	$27.00	$57	$65	$123
Shock HQ 5 Days	($19.35)	$20.59	$33.19	($23)	$115	$92
High LNG Supply	($9.02)	$6.17	$24.64	($98)	$48	($50)
Low LNG Supply	($6.86)	$9.39	$29.10	$77	$77	$154
High Load	($23.92)	$11.99	$30.78	($412)	$90	($322)
Oil Retirements; Renewable Replacement	($4.76)	$5.62	$23.46	$42	$40	$82
Nuclear Retirements; Renewable Replacement	($5.21)	$6.61	$25.05	$96	$53	$149
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($5.60)	$18.75	$33.69	$412	$119	$531
Oil Retirements; Gas / Dual Fuel Replacement	($7.17)	$8.75	$28.71	$41	$74	$115
Nuclear Retirements; Gas Replacement	($5.04)	$9.40	$29.51	$126	$78	$204
Nuclear Retirements; Gas / Dual Fuel Replacement	($3.99)	$9.47	$28.07	$166	$72	$238

Table 43. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Extended Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
Risk Premium x1.25	($6.47)	$3.71	$17.66	($97)	$57	($40)
Shock HQ 1 Day	($6.58)	$3.59	$14.44	($104)	$32	($72)
Shock HQ 5 Days	($7.14)	$4.17	$15.24	($104)	$38	($66)
High LNG Supply	($6.01)	$2.26	$13.03	($129)	$21	($108)
Low LNG Supply	($7.28)	$5.70	$16.28	($60)	$45	($15)
High Load	($14.33)	$5.69	$16.44	($303)	$46	($256)
Oil Retirements; Renewable Replacement	($4.10)	$2.17	$12.98	($55)	$20	($35)
Nuclear Retirements; Renewable Replacement	($2.66)	$2.00	$13.10	$13	$21	$34
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($9.05)	$4.52	$15.82	($160)	$38	($122)
Oil Retirements; Gas / Dual Fuel Replacement	($10.30)	$3.69	$15.02	($225)	$33	($193)
Nuclear Retirements; Gas Replacement	($8.33)	$14.92	$20.36	$192	$81	$274
Nuclear Retirements; Gas / Dual Fuel Replacement	($9.07)	$4.26	$15.03	($170)	$35	($135)

Table 44. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
Risk Premium x1.25	($1.30)	$2.13	$7.13	$22	$25	$48
Shock HQ 1 Day	($1.24)	$1.96	$5.76	$19	$15	$34
Shock HQ 5 Days	($1.28)	$2.06	$5.88	$21	$16	$36
High LNG Supply	($0.76)	$1.58	$5.71	$21	$14	$36
Low LNG Supply	($1.50)	$2.07	$5.79	$15	$15	$30
High Load	($1.45)	$2.16	$5.82	$20	$15	$35
Oil Retirements; Renewable Replacement	($1.28)	$1.45	$5.66	$18	$14	$31
Nuclear Retirements; Renewable Replacement	($1.72)	$1.70	$5.71	$27	$14	$42
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($1.01)	$1.77	$5.71	$20	$14	$35
Oil Retirements; Gas / Dual Fuel Replacement	($1.14)	$1.76	$5.69	$16	$14	$30
Nuclear Retirements; Gas Replacement	($1.16)	$1.94	$5.74	$21	$15	$35
Nuclear Retirements; Gas / Dual Fuel Replacement	($1.71)	$1.97	$5.70	$5	$14	$19

Table 45. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Frequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(2,900,847)	24,421	15,204	(16,536)
Shock HQ 1 Day	0	(2,858,688)	24,512	15,661	(14,689)
Shock HQ 5 Days	(3)	(2,977,660)	27,997	15,904	(14,745)
High LNG Supply	0	(5,097,543)	14,821	17,475	(33,510)
Low LNG Supply	0	(1,906,929)	29,003	16,925	(8,740)
High Load	0	(3,618,832)	13,663	17,991	(23,414)
Oil Retirements; Renewable Replacement	0	(1,117,137)	20,525	14,228	(1,134)
Nuclear Retirements; Renewable Replacement	0	(878,402)	20,550	15,364	(5,703)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(6,395,750)	26,098	10,679	731
Oil Retirements; Gas / Dual Fuel Replacement	0	(6,272,248)	16,245	13,935	(8,465)
Nuclear Retirements; Gas Replacement	0	(12,322,023)	10,131	9,608	(9,084)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(12,852,218)	32,986	13,687	(14,422)

Table 46. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Extended Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(943,020)	32,663	14,022	(7,527)
Shock HQ 1 Day	0	(943,020)	34,807	14,918	(1,041)
Shock HQ 5 Days	0	(1,009,333)	28,426	15,398	(7,076)
High LNG Supply	0	(3,440,918)	40,214	15,327	(5,925)
Low LNG Supply	0	(79,946)	26,394	15,528	(11,646)
High Load	0	(851,854)	25,828	15,910	(6,214)
Oil Retirements; Renewable Replacement	0	(614,918)	10,799	12,116	(3,790)
Nuclear Retirements; Renewable Replacement	0	(332,387)	28,510	12,340	(14,390)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(3,484,459)	10,230	13,081	1,860
Oil Retirements; Gas / Dual Fuel Replacement	0	(3,497,787)	12,036	15,045	(4,948)
Nuclear Retirements; Gas Replacement	0	(7,662,525)	20,129	12,803	(8,296)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(7,277,589)	12,911	16,611	(14,536)

Table 47. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Infrequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
Risk Premium x1.25	0	NA	6,753	11,656	(77)
Shock HQ 1 Day	0	NA	7,237	12,184	(46)
Shock HQ 5 Days	0	NA	6,569	12,068	2,228
High LNG Supply	0	NA	14,294	10,452	(4,307)
Low LNG Supply	0	NA	22,417	13,526	(9,127)
High Load	0	NA	14,520	12,955	(3,628)
Oil Retirements; Renewable Replacement	0	NA	14,728	12,037	(5,228)
Nuclear Retirements; Renewable Replacement	0	NA	8,562	11,244	(1,148)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	NA	10,830	12,482	3,980
Oil Retirements; Gas / Dual Fuel Replacement	0	NA	30,811	14,288	(16,026)
Nuclear Retirements; Gas Replacement	0	NA	7,201	11,064	2,498
Nuclear Retirements; Gas / Dual Fuel Replacement	0	NA	35,900	16,738	(22,968)

2. *Scenarios Evaluating Alternate ESI Proposals*

a) Change in ESI Product Quantities

Several Alternate Proposals consider changes in the quantity of ESI products procured in the day-ahead market, including: No RER, No EIR/RER and RER Plus. Because the assumptions about market participant response differ in each of these Alternate Proposals, they each provide different information about ESI's expected impacts, though we note that the assumed levels of fuel inventory that these alternate ESI designs would incent under each Alternate Proposal are not precisely calibrated, and therefore should be interpreted with this understanding.

The RER Plus Case assumes an additional 600 MW of RER is procured beyond the 1200 MW assumed in the Central Case ESI runs. Compared to the Central Case ESI results, the additional RER increases payments by $99 million, $50 million and $16 million in the Frequent, Extended and Infrequent Cases, respectively. These estimates may overstate the true cost impacts, as no change in fuel-inventory response by market participants is assumed, and the procurement of additional RER (and its corresponding impact on resource revenues) may incent the procurement of additional fuel which will tend to reduce total costs.

Eliminating the RER or eliminating both the RER and the EIR produces lower ESI costs than in the Central Cases in most, but not all, Cases, reflecting the reduction in payments due to the lower quantity of ancillary services procured. This impact is (partially) offset by a reduction in incented energy inventory, which will tend to increase costs. With no RER, payments are reduced relative to the Central case by $73 million, $48 million and $9 million in the Frequent, Extended and Infrequent Cases relative to the ESI costs in the Central Cases, respectively. In the no RER/EIR, payments are reduced by $108 million and $29 million in the Frequent and Infrequent Cases, and increase by $83 million in the Extended Case relative to the ESI costs in the Central Cases. These outcomes reflect both the elimination of the EIR and RER products, which would tend to lower payments, and the reduction in energy supply incented by ESI, which would tend to increase LMPs and, in turn, increase payments. Differences in ESI's impact compared to the proposed ESI design reflects the net impact of these two effects.

With different assumed energy inventory response to ESI's incentives, the operational metrics differ from the Central Case. With No RER, which assumes a 50% reduction in the fuel incentive response to ESI, the operational metrics improve in 8 of 11 instances relative to CMR. Compared to ESI's reliability benefits in the Central Case, the reliability benefits appear more modest under these alternative ESI designs that do not procure RER, as this design change would reduce the incentive for resources to take actions to be available to provide energy in real-time.[62] With No RER/EIR, there is minimal change in these metrics compared to CMR, consistent with the assumption that such an alternative design does not incent any incremental fuel.

b) Change in Strike Price

The Strike Price + $10 Scenario assumes a strike price set at $10 above the level assumed in the Central Case, where the hourly strike price equals the expected RT LMP, based on the DA LMP. Compared to the

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[62] Note that there are four operational metrics, but for the Infrequent Case only three are relevant because one metric – natural gas system use under stressed market conditions – is not applicable due to low natural gas prices.

Central Case, total payments are reduced by $1 million, $15 million and $13 million in the Frequent, Extended and Infrequent Cases relative to the change in costs associated with the ESI Central Cases, respectively. These reductions reflect several effects. First, the total cost of the DA energy option procurement is reduced. Compared to the Central Case, the higher strike price reduces the average DA energy option price by $4.09 per MWh, $3.98 per MWh and $3.07 per MWh in the Frequent, Extended and Infrequent Cases, respectively. The lower option prices do not result in direct reductions in payments, however, because the gains in real-time settlement of these options are also reduced. Thus, in total, the higher strike price reduces the net cost of procuring the ESI products by $5 million, $7 million and $8 million in the Frequent, Extended and Infrequent Cases, respectively. Second, the cost for energy, reflecting LMPs and FER payments, also decreases in the Extended and Infrequent Case by $9 million and $5 million, respectively, while increasing by $2 million in the Frequent Case.

No change in energy inventories are assumed in this Case, thus the operational metrics do not meaningfully change compared to the Central Case. While our analysis does not quantify an impact to reliability benefits, we would nonetheless expect that ESI would create less reliability benefit because, with a reduced closeout cost risk under this Scenario relative to the ESI Central Cases, the incentives to increase inventoried energy would be diminished.[63]

3. *No Incremental Fuel under ESI*

We evaluate a Scenario in which we assume no incremental energy inventory under ESI, but otherwise keep all assumptions unchanged from the Central Case. We expect that ESI will incent incremental fuel (recall, **Section IV.A.1**. demonstrated that ESI appears likely to incent incremental oil in the Central Cases), but we provide this alternative Scenario as a means to better understand the impacts of ESI, independent of its effect on incentives to improve resource deliverability of energy in real-time.

Without incremental energy inventory, total payments are $398 million, $226 million and $40 million higher under ESI compared to the CMR Case. These higher consumer costs relative to the ESI Central Cases are largely driven by increased payments to DA energy, driven by FER payments. For example, in the Extended Case, the average FER price is $3.55 per MWh in the Central Case, which increases to $7.78 per MWh with no incremental fuel inventory, an increase of $4.23 per MWh. Furthermore, there is not a significant decrease in energy prices, as occurs in the ESI Central Cases, because these simulations do not assume the design incents incremental fuel relative to current market rules, which is the primary driver in the reduction in energy prices.

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[63] For further analysis and discussion, *see* ISO-New England, "Energy Security Improvements (ESI): Assessing a Strike Price 'Bias', How adding a 'bias' to the strike price may impact resource incentives," NEPOOL Markets Committee, February 11-13, 2020, https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_iv_esi_assessing_a_strike_price_bias.pptx.

Table 48. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Frequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
RER Plus	($5.37)	$9.48	$30.61	$126	$105	$231
Strike Plus $10	($5.41)	$7.76	$22.91	$69	$61	$131
With Fuel-Related Market Response						
No EIR/RER	$0.06	NA	$22.46	$3	$21	$24
No RER	($4.36)	$5.63	$22.92	$35	$25	$59
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.06)	$11.00	$29.87	$314	$84	$398

Table 49. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Extended Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
RER Plus	($6.31)	$4.36	$16.17	($71)	$51	($19)
Strike Plus $10	($6.56)	$3.40	$10.48	($109)	$25	($84)
With Fuel-Related Market Response						
No EIR/RER	$0.21	NA	$11.43	$7	$7	$14
No RER	($5.83)	$2.28	$11.30	($122)	$6	($117)
No Incremental Oil under ESI						
No Incremental Oil under ESI	($2.39)	$7.78	$17.49	$166	$60	$226

Table 50. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
RER Plus	($1.53)	$2.44	$6.71	$25	$26	$51
Strike Plus $10	($0.85)	$1.35	$2.68	$15	$7	$22
With Fuel-Related Market Response						
No EIR/RER	($0.00)	NA	$5.01	($0)	$7	$6
No RER	($1.05)	$1.76	$5.04	$19	$7	$26
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.02)	$1.94	$5.77	$26	$15	$40

Table 51. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Frequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
RER Plus	0	(2,909,342)	23,866	15,276	(16,538)
Strike Plus $10	0	(2,900,051)	24,432	15,203	(16,413)
With Fuel-Related Market Response					
No EIR/RER	0	3,314	68	(80)	920
No RER	0	(2,448,623)	20,954	11,281	(4,907)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(1,326,266)	645	(1,185)	(2,183)

Table 52. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Extended Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
RER Plus	0	(943,020)	32,663	14,017	(7,527)
Strike Plus $10	0	(943,020)	32,663	14,022	(7,527)
With Fuel-Related Market Response					
No EIR/RER	0	0	0	45	0
No RER	0	(860,078)	35,039	11,597	(7,585)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(739,566)	3,017	(90)	(247)

Table 53**. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Infrequent Case**

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
RER Plus	0	NA	6,753	11,656	(77)
Strike Plus $10	0	NA	6,753	11,656	(77)
With Fuel-Related Market Response					
No EIR/RER	0	NA	0	0	0
No RER	0	NA	5,896	6,609	(416)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	NA	0	0	(0)

4. Non-Winter Scenarios

Two non-winter scenarios evaluate alternate ESI proposals, with one assuming no RER product and the other assuming a strike price set $10 per MWh above the expected RT prices for each hour. Compared to the Central Case, both Alternate ESI Proposals result in lower total payments. With no RER, total payments increases are $48 million and $56 million in the Moderate and Severe Cases, respectively. These payment increases are $41 million and $69 million lower than the corresponding payment increases associated with ESI in the Central Case. These reductions are driven in roughly equal proportion by lower FER payments and reduced net payments for DA energy options.

Increasing the strike price by $10 per MWh also results in lower payments. Compared to the Central Case, both Scenarios results in lower total payments. With a $10 strike price adder, total payment increases are $70 million and $107 million in the Moderate and Severe Cases, respectively. These payments are $19 million and $18 million lower than the corresponding payments in the Central Case. These reductions occur mostly from smaller net payments for DA energy options, which are $15 million and $14 million lower in the Moderate and Severe Cases, respectively. These results are presented in **Table 50** and **Table 51** below.

Table 54. Non-Winter Alternate ESI Proposals - LMPs & Payments, Non-Winter Severe Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Severe Case						
Central Case	($0.23)	$1.12	$7.80	$78	$47	$125
Severe Case - ESI Design Scenario						
Strike Price Plus $10	($0.22)	$1.06	$4.74	$74	$33	$107
No RER	($0.26)	$0.82	$6.21	$47	$8	$56

Table 55. Non-Winter Alternate ESI Proposals - LMPs & Payments, Non-Winter Moderate Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Moderate Case						
Central Case	($0.18)	$0.76	$6.35	$50	$38	$89
Moderate Case - ESI Design Scenario						
Strike Price Plus $10	($0.14)	$0.68	$3.37	$47	$23	$70
No RER	($0.22)	$0.59	$5.67	$31	$16	$48

D. Conclusions Regarding Energy Security Improvements Impacts

The results of the Scenario analysis are generally consistent with and support the conclusions developed in the more detailed review of the Central Case. ESI would be expected to increase incentives for resources to maintain more secure energy supplies and generally improve resources' ability to deliver energy supplies in real-time, through the combination of FER payments and the opportunity to sell DA energy options by supplying the new day-ahead ancillary services created by ESI. These impacts are observed through the strong FER and ESI ancillary service price signals created across Scenarios. These day-ahead new ancillary service opportunities would compensate resources for providing energy security even if they do not supply DA energy, thus increasing incentives to preserve existing energy inventories. These changes would drive reliability benefits and are captured in our analysis through the improvements in fuel system operational outcomes that are indicative of improved reliability. In addition, ESI would be expected to improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory reduces energy production from less efficient suppliers and higher cost fuels.

The analysis also shows that ESI would be expected to increase aggregate payments by load (to suppliers) during periods when stressed market conditions are uncommon or infrequent (as indicated by winter Infrequent Case results and non-winter Moderate Case results). However, under stressed market conditions, total payments by load (to suppliers) could increase or decrease depending on a number of factors, including the nature of the stressed market conditions and the amount of incremental energy inventory incented by ESI.

Under some Scenarios, these incentives and payment impacts become more sensitive to market conditions, including aggregate fuel market supplies and the response of market participants to improve real-time energy deliverability.

V. Appendices

A. Additional Production Cost Model Details

1. Mathematical Optimizer Specification

This section summarizes the market-clearing mechanisms as implemented within the production cost model. It provides a mathematical description of the design of the day-ahead (DA) market under current market rules (CMR) and under the proposed Energy Security Improvements (ESI), and the real-time (RT) market.

a) General notation

<u>Indices</u>

i: participant

t: hour

<u>Continuous variables</u>

$g_{i,t}$: DA energy supply, including physical and virtual supply

$d_{i,t}$: DA bid-in demand, including physical and virtual demand

$r_{i,t}^{Reserve10}, r_{i,t}^{Reserve30}$: operating reserves 10 and 30-minute supply

D_t: RT cleared demand (based on scaled historical data)

<u>Parameters</u>

$c_{i,t}(\cdot)$: DA energy offer

$b_{j,t}(\cdot)$: DA demand bid

b) Model-specific notation

<u>Continuous variables</u>

$o_{i,t}^{EIR}$: EIR option quantity

$o_{i,t}^{GCR10}, o_{i,t}^{GCR30}$: GCR10, GCR30 option quantities

$o_{i,t}^{RER}$: RER option quantity

<u>Parameters</u>

L_t^{DA}: load forecast

$c_{i,t}^{EIR}(\cdot)$: EIR option offer

$c_{i,t}^{GCR10}(\cdot), c_{i,t}^{GCR30}(\cdot)$: GCR10 and GCR30 option offers

$Req_t^{GCR10}, Req_t^{GCR30}$: GCR10 and GCR30 option requirements

$c_{i,t}^{RER}(\cdot)$: RER option offers

Req_t^{RER}: RER option requirements

$Req_t^{Reserve1}$, $Req_t^{Reserve30}$: operating reserve 10 and 30 minute requirements

c) Market Price and Equilibrium under ESI

Market prices:[64]

- **DA LMP =** λ_t^{DA}, paid to physical and virtual supply
- **EIR/FER price =** γ_t, paid to physical supply, including physical energy supply and physical supply providing DA energy options for EIR, but not energy
- **GCGCR10, GCR30, RER prices =** τ_t^*, paid to generators supplying DA energy option for GCR or RER
- **RT LMP =** λ_t^{RT}, paid to generators
- **RT Operating Reserve prices =** $\tau_t^{Reserve*}$, paid to generators supplying reserves, but not energy; paid by RT load

d) Current Day-Ahead Market (CMR)

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}\left(g_{i,t}\right) - b_{i,t}\left(d_{i,t}\right)\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

$$\sum_i \left(g_{i,t} - d_{i,t}\right) = 0 \qquad (\lambda_t^{DA} \text{ free})$$

2. DA financial capability constraint (physical generators): For all i, t,

$$g_{i,t} \leq EcoMax_i \qquad (\alpha_{i,t}^{total} \geq 0)$$

e) Proposed Day-Ahead Market with ESI

ESI imposes three new constraints: an FER requirement, satisfied through EIR, to cover the gap (if any) between the hourly DA load forecast and the supply of physical energy cleared in the day-ahead market, GCR requirements to secure RT operating reserves in advance of the operating day, and an RER requirement to secure sufficient energy is available to cover a large, unexpected contingency.

[64] We only specify which types of resources receive each type of payment (price), recognizing that there are corresponding differences in payments made by different types of resources. However, as the analysis will only consider aggregate payments by load to physical supply, we do not analyze cost allocation across different load serving entities.

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}\left(g_{i,t}\right) - b_{i,t}\left(d_{i,t}\right) + c_{i,t}^{EIR}\left(o_{i,t}^{EIR}\right) + c_{i,t}^{GCR10}\left(o_{i,t}^{GCR10}\right) + c_{i,t}^{GCR30}\left(o_{i,t}^{GCR30}\right) + c_{i,t}^{RER}\left(o_{i,t}^{RER}\right)\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

   A. $\sum_i\left(g_{i,t} - d_{i,t}\right) = 0$ $\quad(\lambda_t^{DA}\text{ free})$

2. DA financial capability constraint (physical generators): For all i, t,

   $g_{i,t} \leq EcoMax_i$ $\quad(\alpha_{i,t}^{total} \geq 0)$

3. FER constraints, satisfied through EIR: for all t,

   $\sum_i g_{i,t} + \sum_i o_{i,t}^{EIR} \geq L_t^{DA}$ $\quad(\gamma_t \ \geq 0, \text{free})$

4. GCR and RER constraint: for all t,

   $\sum_i o_{i,t}^{GCR10} \geq Req_t^{GCR10}$ $\quad(\tau_t^{GCR10} \geq 0, \text{free})$

   $\sum_i\left(o_{i,t}^{GCR10} + o_{i,t}^{GCR30}\right) \geq Req_t^{GCR30}$ $\quad(\tau_t^{GCR30} \geq 0, \text{free})$

   $\sum_i\left(o_{i,t}^{GCR10} + o_{i,t}^{GCR30} + o_{i,t}^{RER}\right) \geq Req_t^{RER}$ $\quad(\tau_t^{RER} \geq 0,, \text{free})$

f) Real-Time Market

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}\left(g_{i,t}\right)\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

   B. $\sum_i\left(g_{i,t}\right) = D_T$ $\quad(\lambda_t^{RT}\text{ free})$

2. RT Operating Reserve constraint: for all t,

   $\sum_i r_{i,t}^{Reserve10} \geq Req_t^{Reserve10}$ $\quad(\tau_t^{Reserve10} \geq 0, \text{free})$

   $\sum_i\left(r_{i,t}^{Reserve10} + r_{i,t}^{Reserve30}\right) \geq Req_t^{Reserve30}$ $\quad(\tau_t^{Reserve30} \geq 0, \text{free})$

2. Opportunity Cost Adder

Opportunity costs reflect foregone revenues of providing energy today rather than the future for resources with limited fuel inventories. As of December 2018, ISO-NE changed market mitigation procedures to provide automated calculation of opportunity costs that allows oil-only and dual-fuel resources to facilitate inclusion of these costs in their market offers. The model calculated opportunity cost bid adders for oil-fired resources in order to maximize oil resource's likelihood of providing energy during its most profitable hours over a 3-day period, as described below.

First, LMPs are forecasted over a 3-day period by solving a 3-day-ahead market. Each oil resource is assumed to begin the 3-day period with a full tank. This provides a conservative (smaller) estimate of the opportunity costs compared to an estimate based on a longer time period. Second, oil resources determine their projected net revenues in each hour over the 3-day period based on expected LMPs and their marginal costs. Third, oil units determine their opportunity cost bid adder such that they would only provide energy during the most profitable hours given expected LMPs.

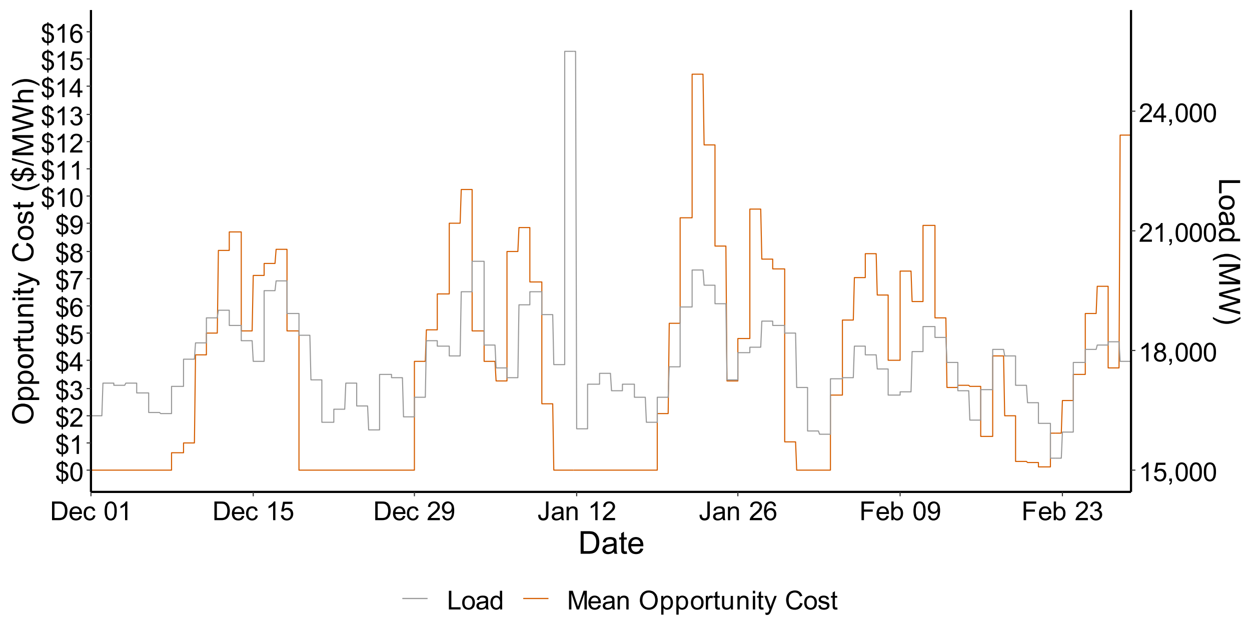
In the illustrative example shown in **Table 56**, an oil resource ranks each hour of expected net revenues from highest to lowest. If this oil resource currently has 9 hours of oil inventory, the resource will set its opportunity cost bid adder equal to the net revenues in its 10th most profitable hour, or $9.04 per MWh. This opportunity cost bid adder would help to ensure that the oil resource would only provide energy during the 9 most profitable hours.

Table 56. Illustrative Oil Hourly Net Revenue

Hour	Bid ($/MWh) [A]	Expected LMP ($/MWh) [B]	Expected Net Revenues ($/MWh) [C]=[B]-[A]	Expected Net Revenues (Rank)
41	$100.69	$117.11	$16.42	1
42	$100.69	$116.46	$15.77	2
43	$100.69	$116.42	$15.73	3
8	$100.69	$115.75	$15.06	4
9	$100.69	$115.43	$14.74	5
40	$100.69	$115.31	$14.62	6
7	$100.69	$114.58	$13.89	7
10	$100.69	$113.20	$12.51	8
11	$100.69	$111.34	$10.65	9
12	**$100.69**	**$109.73**	**$9.04**	**10**
18	$100.69	$108.34	$7.65	11
19	$100.69	$107.98	$7.29	12
37	$100.69	$104.55	$3.86	13
36	$100.69	$104.04	$3.35	14

During periods when oil-fired resources are uncompetitive (i.e., negative expected net revenues) or have large oil inventories, oil-fired resources will have no opportunity costs. Positive opportunity costs tend to occur during periods with high load, high natural gas prices, and limited fuel inventories (e.g., after a prior cold spell). **Figure 32** shows the relationship between daily peak load and opportunity costs for the Frequent Case. Positive opportunity costs tend to overlap with periods of high daily peak loads and increase in magnitude (relative to load) as oil inventories are depleted throughout the winter. Opportunity costs can cause shifts in the timing of supply from energy-limited resources, causing them to supply energy at a later point in time than they otherwise would have without opportunity costs.

Figure 32. Day-Ahead Daily Peak Load and Opportunity Costs, Winter Central Frequent Case



3. Demand Bid Calibration

The demand curves used within the PCM are constructed hourly for the day-ahead market based on historical bids from the relevant historical period for a given scenario. Demand curves are constructed in four stages:

First, historical physical demand, virtual demand (DECs) and virtual supply (INCs) are separated into price buckets and netted against each other to create an aggregate, stepped demand curve.

Second, historical bid quantities are scaled to account for the difference between historical and projected future load levels. An hourly future load quantity is first calculated based on the forecast peak and total energy as reported in the ISO-NE Forecast Report of Capacity, Energy, Loads, and Transmission (CELT 2019).[65] (see **Section III.B.1**). Then, historical bid quantities are scaled by the ratio of future load quantities to historic load quantities.

Third, historical demand bid prices are scaled to future DA LMPs as estimated by the PCM. These changes are driven from a variety of factors, such as assumptions regarding the resource fleet. Future DA LMPs are first calculated by running a version of the day-ahead market with fixed hourly future loads and current market

65 ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (ISO New England, 2018)

rules (no ESI products). Demand bid prices are then scaled by the ratio of these calculated future DA LMPs to historical DA LMPs.

A fourth step is used only in cases modeling EIR. This step accounts for arbitrage opportunities between DA and RT LMPs. As described in **Section III.B.5**, all else equal, DA LMPs will tend to be lower under ESI due to the substitutions between DA energy and EIR. This would lead to divergence between DA and RT LMPs, introducing an arbitrage opportunity. To capture the market's response to this opportunity, demand is increased (i.e., demand curves are shifted to the right) under ESI so that DA LMPs align with expected RT LMPs.

B. Resource Data and Assumptions

This section details the data sources, model assumptions, and methodology used to evaluate the impacts of ESI on energy market outcomes.

1. Electricity Market

Energy suppliers are modeled either as individual (discrete) resources to be optimized by the production cost model, or profiles that are netted off from load, reserve, or DA energy option requirements. This section outlines how the resource characteristics and supply amounts (for profiled resources) are determined.

a) Central Case Resources and Retirements

The electricity supply for winter (2025-26) and non-winter (2026) Cases includes all generators that cleared ISO-NE's thirteenth Forward Capacity Auction (FCA 13) on February 4, 2019 for the Capacity Commitment Period of June 1, 2022 to May 31, 2023. These resources are carried forward into future scenarios unless otherwise removed for specific scenarios. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore).[66] These additions are based on the 10-year projections in ISO-NE's CELT 2019. **Table 4** in the body of this report shows electricity capacity assumptions by resource type under current market rules and ESI.[67]

We assume a number of resource retirements for all scenarios, based on the FCA 13 retirement de-list bids, in addition to retirements that are based on specifications provided by ISO-NE.[68] We also assume the retirement of the Mystic 8 and 9 generating facility, which is subject to a cost-of-service agreement to operate through May of 2024.

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66 New capacity from Generator List with Existing and Expected Seasonal Claimed Capability, S&P Global Market Intelligence. Additional capacity is compared with existing capacity in August 2019. Offshore generation capability derived from nameplate capacity and historical generation values from Vineyard Wind.

67 Under ESI, electricity supply also includes an additional 616 MW of generation sourced from liquefied natural gas.

68 These additional retirements are based on correspondence with ISO New England staff.

Table 57. Assumed Retirements

Resource	Non-Winter Capacity (MW)	Winter Capacity (MW)
Gas Combined Cycle	1,413	1,700
Nuclear Steam	677	683
Gas/Oil Steam	575	560
Coal Steam	383	385
Gas/Oil Combined Cycle	54	57
Oil Combustion (Gas) Turbine	30	41
Bio/Refuse	11	16
Hydro (Daily Cycle - Run Of River)	4	10
Oil Internal Combustion	8	8
Hydro (Weekly Cycle)	2	2
Total	**3,158**	**3,464**

b) Discretely Modeled Resource Characteristics

Optimized resources include coal, dual-fuel, fuel cell, gas-only, oil-only, nuclear, biomass and refuse, price responsive demand (active demand response), and imports. Biomass, price responsive demand, and imports are modeled as aggregated units. All other resource types are modeled as individual units based on unit-specific ISO-NE and SNL data.

Individual resources are modeled based on unit-specific characteristics, including capacity, heat rate, emissions rates, variable costs, and fuel storage capabilities. These capabilities are used within the Production Cost Model to optimize total production cost and meet reserve requirements over the modeling periods. Unit-level characteristics are specific to each modeled generating unit, do not vary across hours, but do vary seasonally in the winter, summer, and shoulder seasons based on expected capacity and outage rates.

Unit capacity is based on the winter SCC in the winter and Expected Summer Peak SCC in the non-winter. EFORd is modeled as a percentage decrement in capacity (in all hours) and based on plant specific seasonal EFORd rates in the winter and summer (June 1st to August 31st). In the shoulder season (March 1st to May 31st and October 1st to November 30th), the outage rate is based on a fleet average of 18% and is applied to all plants equally.[69] Heat rates, allowance costs, non-fuel variable O&M costs, and non-fuel non-allowance variable O&M costs are taken from SNL, or, when missing, averaged by fuel type for dispatchable units.

[69] In September, the outage rate is based on a fleet average for September of 12% and is applied equally as well. This month was split apart to adjust more readily for historically high loads in this month, during which resources would have been less likely to undergo unforced maintenance. For shoulder seasons, the outage rate was based on the publically available information in ISO-NE's morning report. This outage rate is "the sum of capability of all generation scheduled Out of Service (OOS), forced OOS, or reduced for the day, as known at the time of Morning Report development for the peak hour of the day," available under "Generation Outages and Reductions" at https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report/.

i) Biomass and Price Responsive Demand

Biomass and refuse quantity and offers (i.e., marginal costs) are modeled in segments based on historical generation and day-ahead offers from wood and municipal solid waste plants for winters 2013/14 through 2017/18. The historical MW offers are used to generate a supply curve for plants.

ISO-NE implemented Price Responsive Demand effective July 1, 2018. Price Responsive Demand quantity and offers are modeled in three segments based on historical day-ahead offers.

ii) Imports

Imports are modeled as individual generating units similar to biomass and active demand response with prices dependent on capacity. The model includes the following interconnections: Northport-Norwalk (Northpoint connection point), Cross-Sound Cable (Salisbury connection point), New York-New England Northern AC (Roseton and Shoreham connection points), and Hydro Quebec Phase I/II. Offers and capacity are determined using hourly transaction data from ISO-NE beginning June 1, 2012 and ending May 31, 2018. Import offers for all interconnections, excluding Roseton, are set at the mean of observed real-time hourly imports in MW. Import offers for Roseton are the mean of real-time hourly imports segmented by $20 per MWh price bins between $0 and $100 per MWh. The Roseton price bins reflect a supply curve observed in the historical data. Hourly data for Northport-Norwalk, Cross-Sound Cable, Hydro Quebec Phase I/II, and the Shoreham connection point of New York-New England Northern AC did not show meaningful price-supply relationships.

c) Hourly Profiled Resource Characteristics

i) Solar, Wind, and Hydroelectric

Unit characteristics for solar, wind, and hydroelectric power are derived from the generator list reported in CELT 2019 and cleared in FCA 13.[70] Future hourly generation for renewable and hydroelectric units is based on historical hourly generation in the winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity. Scaled resources include on-shore wind, photovoltaic solar, run-of-river, and pondage hydroelectric power. Hourly power generation is based on historical data received from ISO-NE.

ii) Pumped Storage and Battery Storage

Future generation for pumped storage units is based on a 24-hour generation profile received from ISO-NE that is scaled proportionally to capacity in each hour. The storage profiles model pumping or charging as extra demand. To model round-trip efficiency for storage units, energy consumed during pumping or charging exceeds energy produced.

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70 ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/

iii) Off-Shore Wind

Unit characteristics for off-shore wind are derived from modeled hourly generation data received from ISO-NE that is based upon offshore meteorological buoy wind speed data.

d) Real-Time Reserve Provision

Real-time operating reserves are modeled for 10-minute and 30-minute operating reserve products. We do not model separate spin and non-spin 10-minute reserves, but rather model a single 10-minute product.

Offline reserve capabilities are based on historical analysis of Claim 10 and Claim 30 audit data. Claim 10 and Claim 30 capabilities for dispatchable generation (oil, gas, coal, and dual-fuel) are based on the weekly Claim 10 and Claim 30 Capability report generated by ISO-NE over the period from December 1, 2018 through February 28, 2019. Offline reserve capabilities are constant over a winter. For the non-winter period, the offline reserve capability is calculated between March 1, 2019 and October 1, 2019.

Dispatchable hydroelectric power reserve capabilities are profiled from hourly averages of five-minute data from June 1, 2012 through December 31, 2018 on 10-minute operating reserves, 10-minute spinning reserves, and 30-minute spinning reserves. The future reserve profile for hydroelectric units is based on the hourly data in the specific winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity.

e) Day-Ahead Energy Option Provision

The model assumes that oil, gas, dual-fuel, coal, run of river hydro, weekly hydro, pond hydro, and pumped storage are able to provide day-ahead energy options. For resources not modeled as profiles (as explained in **Section V.B.1.b**. above), resources provide GCR10, GCR30, EIR, and RER240 based on measures of offline reserve capability (for resources supplying from a cold start) or ramp capability (for resources that must be on-line to supply reserves).

Resources able to provide day-ahead energy options from a cold start are combustion turbines and internal combustion engines. GCR10 and GCR30 capabilities are based on historical Claim 10 and Claim 30 data provided by ISO-NE. EIR and RER240 capabilities are based on modeled Claim 60 (for EIR) and Claim 240 (for RER) values modeled and provided by ISO-NE.[71]

Resources able to provide day-ahead energy options only when also providing energy are combined cycle, steam, and coal units. These units must be supplying energy in order to be cleared by the production cost model for day-ahead energy options. The capability of these resources to provide day-ahead energy options is based on ramp rate data provided from ISO-NE.

Resources that are modeled as profiles can provide GCR10, GCR30 or RER240 based on historic levels of real-time operating reserves (see **Section V.B.1.c**., above). Resources are assumed to provide day-ahead

[71] For more information, see Ewing, Ben, "Energy Security Improvements: Market-Based Approaches," January 13-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx.

energy options in equivalent quantities to historic operating reserve levels. Generally, these resources provide GCR10 and GCR30. In some rare hours, where historic operating reserves exceed the GCR requirements, these resources are modeled to provide RER.

2. *Fuel and Emission Prices*

a) Natural Gas

Projected natural gas prices take Algonquin City Gate daily spot prices from winters 2013-14, 2016-17, and 2017-18 in dollars per MMBtu.[72] While the model forecasts hourly gas constraints using historical inventory and deviation from heating degree day, projected gas prices are unadjusted from the daily base year price and are constant over the 24 hours of a gas-day. **Figure 33** shows the prices for natural gas and other fuels used in the winter months, while **Figure 34** shows these prices for the non-winter months.

b) LNG

Natural gas units with a forward LNG contract exercise calls on these supplies when the Algonquin spot price exceeds a trigger price, set to $16 per MMBtu. When exercised, these supplies have a production cost of $10 per MMBtu, which is the commodity price under the assumed contract. The trigger price exceeds the commodity price to account for the opportunity cost of each call, as the contract only provides for 10 days of supply and exercising calls when prices are too low would limit the opportunity to exercise on days when the price could be higher.

c) Oil

Units which use oil for their primary or secondary fuel may use 1) distillate fuel oil (DFO), 2) residual fuel oil (RFO), 3) jet fuel, or 4) kerosene. Forecasted prices use the December 2021 futures prices for each oil type: New York Harbor Heating Oil Futures NYMEX, New York Harbor Residual Fuel Oil 1.0% Sulfur futures, and Gulf Coast Jet Fuel (Platts) Futures Quotes for jet fuel and kerosene.[73] These fuel prices are fixed across all hours in both winter and non-winter Cases. Figures 3a and 3b show fuel prices for natural gas over the three winter severities and two non-winter severities, the LNG contract trigger price, and DFO and RFO oil.

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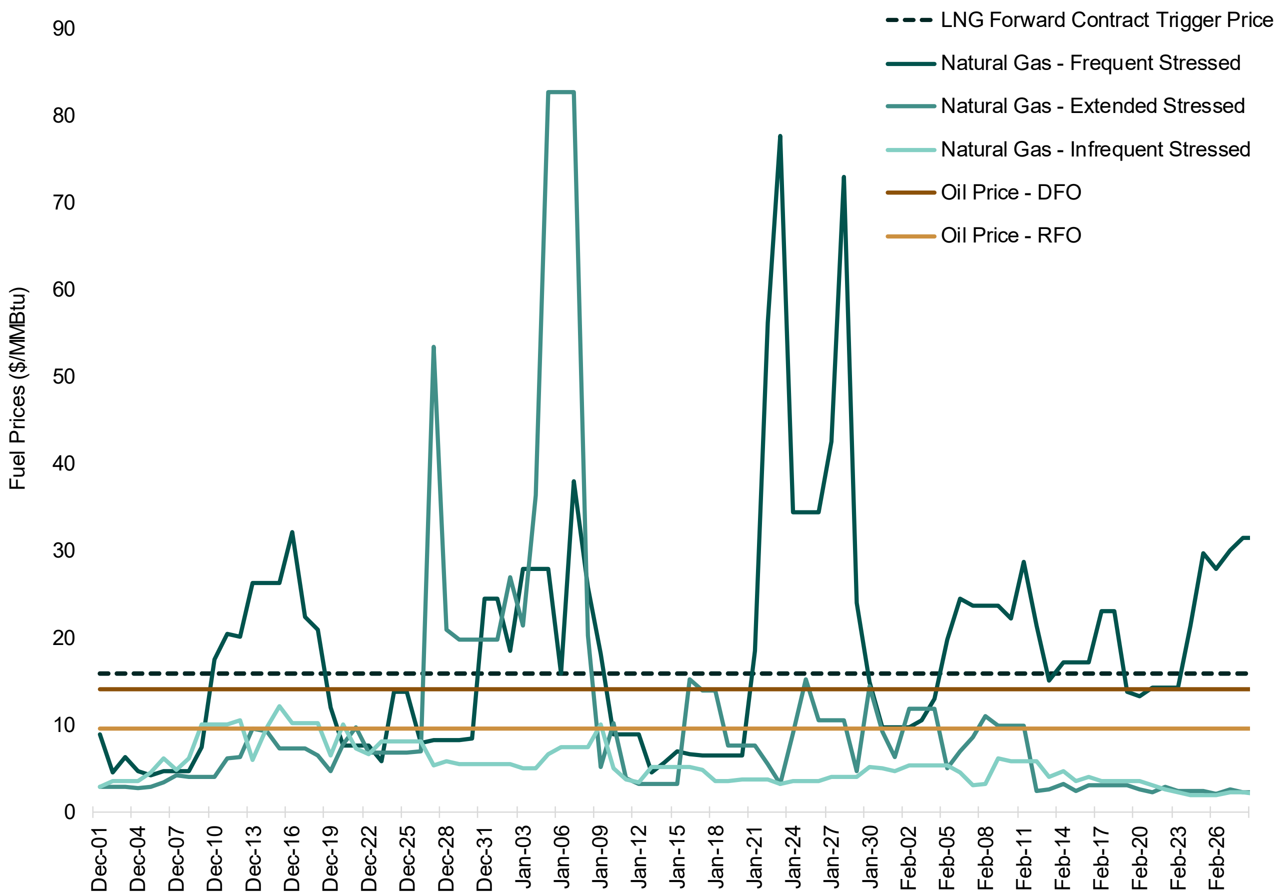
[72] Source data year depends on winter severity. Algonquin City Gate prices from S&P Global Market Intelligence.

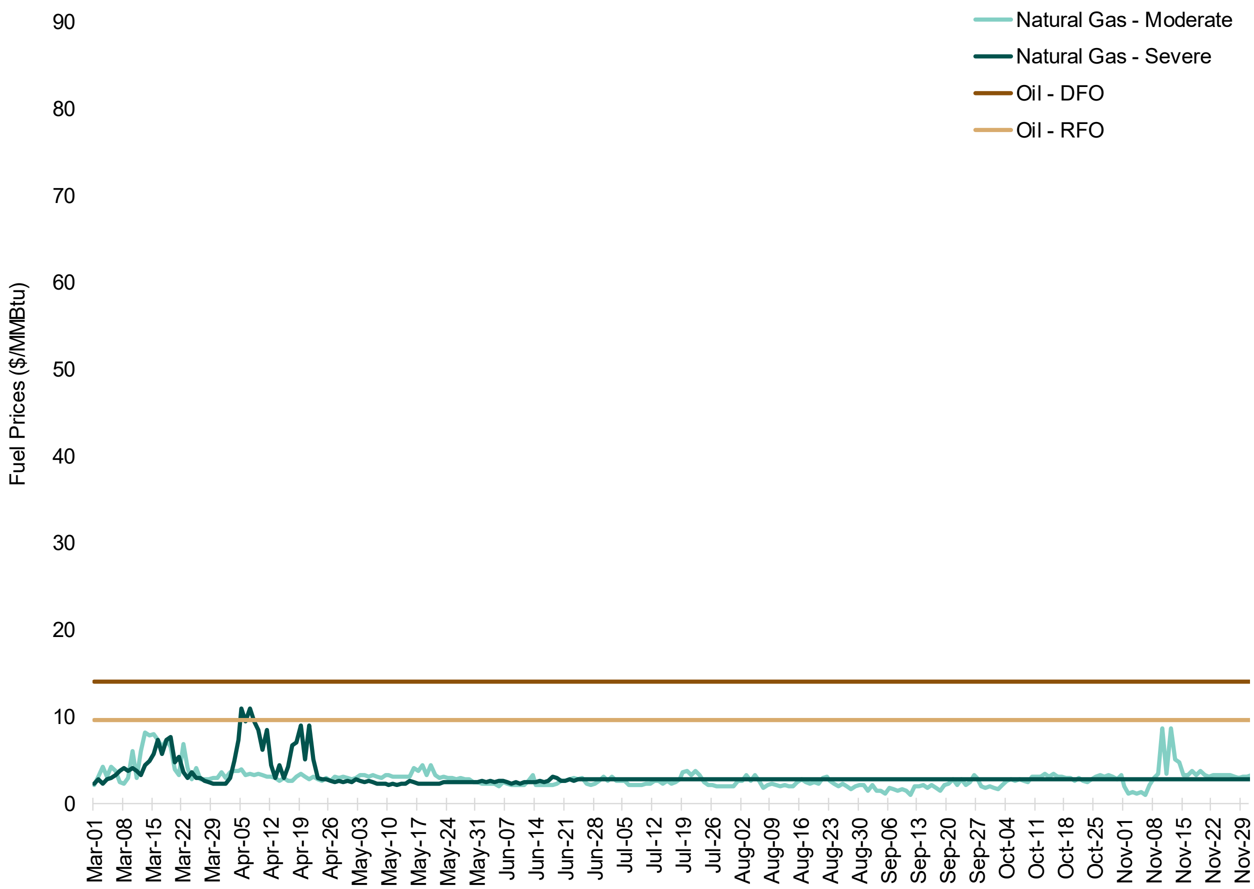
[73] December 2021 was selected due to observed trading activity and market liquidity.

Figure 33. Future Fuel Prices by Winter Case ($ per MMBtu)[74]



[74] The Algonquin Natural Gas Price series is based on 2013/14, 2016/17, and 2017/18 prices for frequent, infrequent, and extended stressed conditions, respectively. The LNG Forward Contract Trigger Price is $16 per MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16 per MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10 per MMBtu. The DFO - Oil price is $14.06 per MMBtu ($81.27 per BBL), based on December 2021 Futures. The RFO - Oil price is $9.64 per MMBtu ($60.58 per BBL), based on December 2021 Futures.

Figure 34. Future Fuel Prices by Non-Winter Case ($ per MMBtu)[75]



d) Coal

Coal prices are quarterly and based on shipments to the electric power sector by state from the Energy Information Administration.[76]

75 The Algonquin Natural Gas Price series is based on 2017 and 2018 prices for the moderate and severe non-winter conditions, respectively. The LNG Forward Contract Trigger Price is $16 per MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16 per MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10 per MMBtu. The DFO - Oil price is $14.06 per MMBtu ($81.27 per BBL), based on December 2021 Futures. The RFO - Oil price is $9.64 per MMBtu ($60.58 per BBL), based on December 2021 Futures.

76 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Retrieved from https://www.eia.gov/coal/data/browser/#/topic/45?agg=1,0&geo=8&rank=g&freq=Q&rtype=s&pin=&rse=0&maptype=0&ltype=pin&ctype=map&end=201802&start=200801

e) Emissions

Emission costs include costs per ton of emitted CO_2, SO_2, and NOx. As with fuel prices, the production cost model assumes fixed allowance prices to capture the cost of environmental emission requirements. Thus, the model does not endogenously solve for market-clearing allowance prices needed to comply with aggregate, quantity-based limits (e.g., emission caps) imposed by certain environmental requirements, given production decisions across the entire year.

The CO_2 emissions price for each fuel type is the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.[77] We do not model allowance prices, holdings, or acquisitions and do not distinguish by "regulated entities." All units are assumed to take the RGGI price as the price for their CO_2 emissions. Emissions prices for SO_2 are derived from annual allowances of SO_2 acid rain and take the May 2019 forward price for winter and non-winter months.[78] Emissions prices for NOx are derived from annual allowances from the US Environmental Protection Agency Cross-State Air Pollution Rules and take the May 2019 forward price for winter and non-winter months.[79] Total emissions for each emission type reflect a combination of factors, including the quantity of each type of fuel consumed. **Table 58** provides total winter fuel consumption by fuel type for each Central Case.

Table 58. Total Fuel Consumption by Fuel Type, Winter Central Case

Case		Total Natural Gas (MMBTU)	Total Oil (BBL)	Total Coal (MMBTU)
Frequent Case	CMR	48,779,867	8,435,575	11,973,792
	ESI	46,726,510	8,738,681	11,973,792
Extended Case	CMR	70,954,852	3,925,122	8,030,226
	ESI	70,924,801	3,856,651	8,030,226
Infrequent Case	CMR	83,546,079	1,318,809	6,849,625
	ESI	83,546,079	1,314,057	6,849,625

By assuming allowance prices consistent with current market transactions, we intend to simulate market outcomes broadly consistent with these limits and, to the extent that results are inconsistent with these requirements, can test whether such differences have a material impact on the efficacy of the ESI proposal or the conclusions we draw from our analysis. Within New England, one important regulation with an annual aggregate cap is the Massachusetts CO_2 emission cap, which would cap emissions from Massachusetts' generation facilities at approximately 7.38 MT in 2025.[80] As shown in **Table 59**, our analysis finds that, with the assumed emission allowance prices of $9.67 per MT in 2025/26, that total emissions would exceed that

[77] Elements of RGGI. Retrieved from https://www.rggi.org/program-overview-and-design/elements

[78] S&P Global Market Intelligence for Acid Rain Annual SO_2 Allowances.

[79] S&P Global Market Intelligence for Annual Cross-State Air Pollution (CSAPR) NOx Allowances.

[80] ISO New England. (2017, September 26). Greenhouse Gas Regulatory Update. Retrieved from https://www.iso-ne.com/static-assets/documents/2017/09/ghgupdate_20170926.pdf

amount in all combinations of winter and non-winter month Cases. To test the sensitivity of this result to a higher emission allowance price that could be consistent with a lower MA emission quantity, we assume the Massachusetts' CO_2 emission allowance price is $14.67 per MT, which is $5 per MT higher than Central Case.[81] These tests find that Massachusetts' CO_2 emissions are reduced in all cases, and for some combinations of winter and non-winter Cases are below the cap. Moreover, aggregate changes in ESI impacts are relatively similar to our Central Case; for example, total payments change by small amounts in the Extended and Infrequent Cases, and are reduced by $11 million (from $132 million to $121 million) in the Frequent Case.

Table 59. Massachusetts Annual CO_2 Emissions

Non-Winter Case		Severe			Moderate		
Winter Case		**Frequent**	**Extended**	**Infrequent**	**Frequent**	**Extended**	**Infrequent**
MA Limit 2025 [1]		**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**
Central Cases							
MA CO_2 Emissions (metric tons)	CMR	8,824,865	8,037,318	7,691,581	8,623,248	7,835,701	7,489,964
	ESI	8,748,793	7,976,487	7,681,679	8,547,176	7,774,871	7,480,062
	Change	(76,072)	(60,831)	(9,902)	(76,072)	(60,831)	(9,902)
$5 MA CO_2 Adder							
MA CO_2 Emissions (metric tons)	CMR	8,515,251	7,731,520	7,385,709	8,289,895	7,506,164	7,160,353
	ESI	8,432,947	7,673,953	7,375,569	8,207,592	7,448,598	7,150,213
	Change	(82,304)	(57,567)	(10,140)	(82,304)	(57,567)	(10,140)

3. *Oil Starting Inventory, Oil Holding Costs, and LNG Contracting*

a) Oil Starting Storage

Resources that use oil for their primary or secondary fuel have additional characteristics related to fuel storage, consumption, and replenishment rates. These refueling characteristic assumptions are based on periodic oil resource survey data from August 2014 through April 30, 2019, received from ISO-NE. Under CMR, historic inventory levels are used.

This section describes our assumptions of each resource's starting storage under CMR and ESI.

i) Initial Inventory under Current Market Rules

Each resource's projected starting storage under current market rules is based on the 2018-2019 average inventory as of December 1st.

81 In principle, actual emissions can be above the statutory cap through the use of banking provisions in the Massachusetts system. However, the consequences of banking for compliance in a given future year are complex, due to certain dynamic adjustments made to total annual allowance allocations when allowance banking occurs in prior years. Thus, determining precise thresholds for compliance in future years is difficult.

ii) Initial Inventory under ESI

Each resource's average December inventory over the period 2014 to 2016 is used as a starting point for determining the quantity of fuel assumed under ESI. From this starting point, adjustments are made to reflect multiple factors associated with the benefits of incremental storage, relative to CMR levels:

1. For a subset of resources with at least seven days of storage, initial inventory is set to their CMR (December 2018) initial inventory level. Analysis found that further increasing initial inventories for these resources beyond 7-days of fuel provided little economic value, potentially imposing holding costs in excess of additional revenues.
2. For resources with smaller tank sizes (no more than three days of storage and refueled by truck) and inventories at low levels over the period 2014 to 2016, initial inventories are set, at a minimum, to 70 percent of their maximum storage. These resources accrue sufficient energy option revenues and FER payments to compensate their incremental oil holding costs.
3. The most-efficient (low heat rate) resources are assumed to hold larger initial inventories, set at 5% or 10% above average December inventories for 2014 to 2016 depending on the level of efficiency.
4. The most-inefficient (high heat rate) resources are assumed to hold smaller initial inventories, set at the mid-point between the average December 2014-16 inventories and the average December 2018 inventory (i.e., the level assumed under CMR).

Resources that refuel their oil inventory via pipeline are assumed to refuel oil as often as is required to supply energy under both CMR and ESI.

b) Oil Holding Costs

Storing oil imposes an economic cost, referred to as a "holding cost." If a resource procures stored fuel oil, there is risk that this fuel is not consumed during the winter season, and the resource is still holding the fuel at the end of the winter. We measure the cost associated with holding quantities of oil at the end of a winter season. We model holding costs as the combination of three costs faced by any resource that purchases oil: fuel carrying cost, price risk, and liquidity risk.

- **Carrying Cost**: carrying cost reflects the opportunity cost of purchasing oil and storing it for a period of time in a tank rather than using the capital in another way. The risk free component of a resource's weighted average cost of capital represents this opportunity cost of funds.
- **Liquidity Risk**: once purchased, fuel-oil can be difficult to re-sell. Being left with oil in the tank at the end of a winter season may therefore tie up valuable assets for the resource until the next winter season. This liquidity risk can be represented as a risk premium on top of the risk-free opportunity cost of capital, or simply the difference between a resource's weighted average cost of capital and the risk-free rate (often represented by T-bills). Thus, taken together, the carrying cost and liquidity risk can be represented by a resource's weighted average cost of capital.
- **Price Risk**: price risk refers to the risk a resource faces of the price of oil falling below the original purchase price before the end of the storage period (e.g. the end of the winter season). If the price of oil falls below its original purchase price, the resource will be left with a depreciated asset. The price

of a "put option"—a financial instrument that offers the purchaser of the option the opportunity to sell the product (in this case oil) at a pre-determined price—reflects the value of this price risk.

The combination of carrying cost, liquidity risk, and price risk represent an upper bound on the holding costs a resource may incur. We estimate holding costs in dollars per megawatt-hour ($ per MWh) for each generating unit based on the amount of fuel it has remaining at the end of the winter model run. Specifically, for each unit, we calculate the following relationship:

Holding cost ($/MWh) = holding cost ($/BBL) ÷ fuel energy content (MMBtu/BBL) × unit heat rate (Btu/kWh/1000)

Where the components are defined as:

- ***holding cost ($/BBL)*****:** the combination of carrying cost, liquidity risk, and price risk for units combusting RFO and DFO. Drawing from past work, we estimate carrying cost and liquidity risk as the weighted average cost of capital of the price of RFO or DFO in $/BBL.[82] To represent price risk, we draw from past work that estimated a fuel specific premium payment on a put option. We illustrate our assumptions in the table below:

Table 60. Fuel Holding Costs ($/BBL)

	Fuel Price	WACC	Put Option	Holding Cost
	[A]	[B]	[C]	[D] = [A]×[B] + [C]
RFO	$88.30 / BBL	8%	$6.14	$13.20 / BBL
DFO	$89.54 / BBL	8%	$8.46	$15.62 / BBL

- ***fuel energy content (MMBtu/BBL)*****:** RFO and DFO contain different energy contents per barrel of fuel. Specifically, RFO contains 6.287 MMBtu per BBL and DFO contains 5.817 MMBtu per BBL.[83]
- ***unit heat rate (Btu/kWh)*****:** We derive unit specific heat rates from SNL Financial. SNL reports values in Btu per kWh. To convert to MMBtu per MWh, we divide by 1,000.[84]

c) Natural Gas Modeling

In winter months under CMR and in non-winter months under both CMR and ESI, we assume no forward LNG contracting. However, in the winter months under ESI, we assume that market participants would enter into forward contracts with LNG terminals that provide supplies of natural gas. The total capacity of natural gas available for forward contracting was determined through an analysis of various demands on LNG terminal

[82] Hibbard, Paul and Todd Schatzki, "Further Explanation on Rate Calculations," May 28, 2014. https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun32014/a02a_analysis_group_memo_05_28_14.pdf

[83] "Energy Units and Calculators, Explained," U.S. Energy Information Administration, https://www.eia.gov/energyexplained/index.php?page=about_energy_units.

[84] (Btu / kWh) × (1000 kWh / 1 MWh) × (1 MMBtu / 1,000,000 Btu) = MMBtu / 1,000 MWh.

capability during the future modelled year, 2025/26. This analysis considers the capacity available from the LNG terminals, as the terminals would not be expected to sign contracts for supplies that exceed the capacity they can deliver on each day. This analysis is shown in **Table 61**.

First, we estimate the amount of LNG that would be needed to meet LDC demand on a "design day". These LNG supplies are needed by LDCs to ensure they can meet peak demand on a "design day," the hypothetical day in which the LDCs are expected to put the greatest demand on the gas system. LDC design day needs are estimated to be 0.71 Bcf per day.

Second, we determined available natural gas supply from the LNG terminals. With the assumed retirement of DOMAC, supplies are assumed to be provided by Canaport, as limited by pipeline capability. Potential natural gas supply capacity from the LNG terminals is estimated to be 0.833 Bcf per day.

Third, deliverable natural gas capacity for the electricity sector was calculated as the difference between potential capacity from the LNG terminals and LDC design day demand. The amount is 0.12 Bcf per day. Thus we assume that forward contracts for this amount of fuel would be available to the electric power sector.

Table 61. Quantity Available for LNG Forward Contracting[85]

			Source
LDC Design Day Temperature (HDD)	[A]	75	Assumption
Pipeline Import Capacity (Bcf/day)	[B]	3.59	FCA 14 presentation
LDC Demand on Design Day (Bcf/day, ISO Model)	[C]	5.76	ISO NE model
Satellite LNG Injection Quantity on Design Day (Bcf/day, ISO Model)	[D]	1.46	ISO NE model, capped at 1.456 Bcf/day
LDC Design Day Demand to be met by LNG (Bcf/day)	[E]=[C]-[B]-[D]	**0.71**	
Assuming LDCs contract LDC Design Day Demand as firm capacity with LNG terminals…			
Canaport LNG Terminal Capacity (Bcf/day)	[F]	1.20	OFSA
M&N Pipeline Capacity (Bcf/day)	[G]	0.833	OFSA
Canaport Deliverable Capacity (Bcf/day)	[H]= Min([F],[G])	0.833	OFSA
Total LNG Capacity without DOMAC (Bcf/day)	[I]=[H]	**0.833**	Calculation
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (Bcf/day)	[J]=[I]-[E]	**0.12**	
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (MMBtu/hr)	[K] = [J] converted	**5,313**	
Total Gas-only Capacity assumed with LNG forward contracts (SCC MW)	[L]	**616**	Based on most efficient gas-only units
Percentage of LNG reserved for Design Day Demand available for electrical generators		**100%**	

85 Sources are: [1] Norman Sproehnle, "Reliability Reviews for Fuel Security: Model Inputs, Results, and Criteria for Unit Retention in the Forward Capacity Market (FCM)," July 31, 2018, "a2_1_iso_presentation_reliability_reviews_for_fuel_security.pptx"; [2] ISO-

The forward LNG contract was assigned to the more efficient combined cycle gas-only resources. We assume that the forward contract would have 10 call options over the 90-day winter period. The modeled contract has a reservation of $13.19 per MMBtu, and a strike price of $10 per MMBtu.[86] This means that resources must pay $13.19 per MMBtu prior to the winter to secure the contract, then will be able to purchase gas at the strike price of $10 per MMBtu when exercising a call.

d) Incentives for Investment in Incremental Fuel Oil, Scenario Results

Section IV.A analyzes the incentives for investment in incremental fuel oil. Our analyses include **Table 11** to **Table 13**, which compare the new revenues created by ESI to incent fuel oil use, through FER payments and DA energy option procurement, against incremental fuel oil holding costs. **Table 62** to **Table 64** provide the same comparison for several alternate ESI designs, including the RER Plus, Strike Plus $10, and No RER scenarios, for the Frequent, Extended and Infrequent Cases, respectively. These tables provide the *change* in net revenues (new ESI revenues net of holding cost) for holding incremental fuel oil under each alternate ESI design as compared to CMR.

Directionally, the change in net revenue from each alternate ESI design, as compared to the ISO-NE proposal, reflects the change in scope of the services procured relative to the ISO-NE proposal.[87] For example, a larger RER quantity ("RER Plus") leads to a larger increase in net revenues from holding incremental fuel oil, while eliminating the RER ("No RER") reduces the net revenues from holding incremental fuel oil relative to the ESI proposal.

As the results in **Table 62** to **Table 64** demonstrate, proposals to reduce the ESI services procured, such as the elimination of RER, would tend to reduce the aggregate incentive to procure incremental fuel oil relative to the ISO-NE proposal. More importantly, this reduction in incentive would also reduce incentives *on the margin*, as the elimination of RER tends to reduce FER and GCR prices, especially during periods of system stress. This result was illustrated in **Figure 20** and **Figure 21**. These lower prices would reduce the revenues earned from selling DA energy or ancillary services during periods of system stress, and may therefore reduce the likelihood that oil units (or other resources) procure fuel (or take other actions) necessary to sell these products and ensure that they are available to provide energy in RT. Reducing such incentives would therefore adversely impact the design's ability to improve the region's energy security by incenting greater fuel procurement.

NE, LDC Gas Demand model, "2018_ICF_LDC_gas_demand.xlsx" [3] ISO-NE, "Operation Fuel-Security Analysis," January 17, 2018. [4] Discussion with ISO-NE, July 10, 2019.

[86] Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

[87] We caution the reader from drawing precise quantitative conclusions about the magnitudes of these incentives under the alternatives as they compare to the ISO's proposal. The values presented in **Table 62** to **Table 64** for RER Plus and Strike Price plus $10 reflect the same incremental fuel inventory assumptions as in the Central Case, while the No RER value assumes one-half of the incremental fuel inventory as was assumed in the Central Case. In each case, these assumptions are not precisely calibrated to reflect the differences in incentives under each alternative design relative to the ISO's proposal.

Table 62. New ESI Revenues and Change in Holding Costs, Winter Frequent Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$14	$5,452	$139	$5,577
Dual Fuel, CT	14	-$118	$5,875	$2,172	$7,929
Oil Only, CT	70	-$134	$1,784	$5,735	$7,385
Oil Only, Steam	13	-$1,257	$6,207	$583	$5,532
RER Plus					
Dual Fuel, Combined Cycle	17	-$6	$6,616	$221	$6,831
Dual Fuel, CT	14	-$110	$7,129	$2,875	$9,894
Oil Only, CT	70	-$134	$2,141	$7,632	$9,639
Oil Only, Steam	13	-$1,256	$7,595	$1,055	$7,394
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$14	$5,427	$124	$5,537
Dual Fuel, CT	14	-$118	$5,955	$1,940	$7,777
Oil Only, CT	70	-$134	$1,827	$5,219	$6,911
Oil Only, Steam	13	-$1,257	$6,315	$561	$5,619
No RER					
Dual Fuel, Combined Cycle	17	-$1	$3,564	$47	$3,610
Dual Fuel, CT	14	-$71	$2,946	$1,317	$4,192
Oil Only, CT	70	-$91	$851	$1,844	$2,604
Oil Only, Steam	13	-$1,406	$3,179	$111	$1,884

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 63. New ESI Revenues and Change in Holding Costs, Winter Extended Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$112	$2,113	$61	$2,063
Dual Fuel, CT	14	-$124	$1,760	$1,199	$2,835
Oil Only, CT	70	-$88	$654	$2,032	$2,598
Oil Only, Steam	13	-$1,291	$2,646	$98	$1,453
RER Plus					
Dual Fuel, Combined Cycle	17	-$112	$2,628	$110	$2,627
Dual Fuel, CT	14	-$124	$2,410	$1,641	$3,927
Oil Only, CT	70	-$88	$891	$3,296	$4,099
Oil Only, Steam	13	-$1,288	$3,597	$230	$2,539
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$112	$2,096	$55	$2,039
Dual Fuel, CT	14	-$124	$1,685	$1,069	$2,630
Oil Only, CT	70	-$88	$630	$1,857	$2,399
Oil Only, Steam	13	-$1,291	$2,552	$102	$1,364
No RER					
Dual Fuel, Combined Cycle	17	-$6	$1,207	$23	$1,223
Dual Fuel, CT	14	-$116	$868	$416	$1,167
Oil Only, CT	70	-$80	$267	$339	$527
Oil Only, Steam	13	-$819	$1,316	$13	$509

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 64. New ESI Revenues and Change in Holding Costs, Winter Infrequent Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$254	$785	$12	$543
Dual Fuel, CT	14	-$435	$150	$444	$159
Oil Only, CT	70	-$84	$7	$720	$643
Oil Only, Steam	13	-$1,315	$94	$3	-$1,218
RER Plus					
Dual Fuel, Combined Cycle	17	-$254	$961	$38	$745
Dual Fuel, CT	14	-$435	$182	$560	$307
Oil Only, CT	70	-$84	$5	$1,270	$1,191
Oil Only, Steam	13	-$1,315	$101	$21	-$1,194
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$254	$541	$10	$296
Dual Fuel, CT	14	-$435	$106	$394	$65
Oil Only, CT	70	-$84	$5	$659	$581
Oil Only, Steam	13	-$1,315	$69	$3	-$1,243
No RER					
Dual Fuel, Combined Cycle	17	-$193	$662	$3	$472
Dual Fuel, CT	14	-$298	$120	$221	$43
Oil Only, CT	70	-$66	$3	$89	$27
Oil Only, Steam	13	-$709	$81	$0	-$628

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

C. Day-Ahead Energy Options Offers

ESI requires the procurement of DA energy options from suppliers in the market. Under ESI, market participants would submit offers reflecting their willingness to accept the obligation to settle ("closeout") at the option's pay out terms. In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to accept the settlement obligation reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. Thus, valuations will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[88] Further, the ESI design assumes that all market participants submit offers for DA energy options that reflect their underlying valuation, with the resulting market-clearing price reflecting the marginal offer given the quantity administratively procured. The resulting price may differ from the price that emerges from financial markets, where equilibrium prices reflect bi-lateral transactions between those willing to accept and willing to pay for the option, as ISO-NE procures the options on behalf of consumers. The finance literature does not provide unique methodologies to estimate option offer prices under these circumstances.

The energy option offer includes two components: the expected closeout costs and a risk premium. First, we describe the approach taken to estimating the expected closeout costs and then describe the approach taken to estimating the risk premium.

1. Expected Closeout Costs

The estimates for the expected closeout costs are based on the difference between the real-time LMP (RT LMP), and the "strike price" (K) in each hour. Resources owe a payment of $(RT\ LMP - K)$ to closeout the option, if the option is "in the money", or when $(RT\ LMP - K) > 0$. Otherwise the payout is zero. Thus, the key driver of the bidding for the ESI products is the volatility of the real-time settlement, or in other words, $max\{(RT\ LMP - K), 0\}$.

For each hour when estimating offer prices, the **strike price, *K*,** is set to be equal to the historic **DA LMP** in that hour.

We compute the expected closeout costs through a multi-step process.

1. We use historical data provided by ISO-NE on LMPs between June 2012 and May 2019 to compute the historical time series of **RT LMP** minus **K**.

[88] Cochrane and Saa-Requejo, 1999, consider approaches to derivative valuation that reflect "good deals" given opportunities to partially hedge a derivatives risk.

2. We estimate fitted values for the difference in RT LMP and strike price *(RT LMP - K)* for each hour. This fitted value provides a single, point estimate of *(RT LMP - K)*. The fitted value is estimated using the following linear model, estimated over our sample:

$$(RT\ LMP - K) = \beta_1(HDD) + \beta_2(Hour\ of\ Day) + \beta_3(Day\ of\ Week) + \beta_4(Month\ of\ Winter) + \beta_4(Winter) + \varepsilon$$

3. We calculate model residuals ε from our estimated model as the difference between the actual *(RT LMP - K)* and the fitted *(RT LMP - K)*.
4. Using a Monte Carlo method, we simulate a distribution for *(RT LMP - K)*. To create this simulated distribution for each hour, we take the fitted value and randomly draw one residual from the sample of model residuals, ε. We replicate this step 1,000 times (with replacement) to create a distribution of *(RT LMP - K)* with 1,000 values.
5. Having created the distribution of *(RT LMP - K)* with 1,000 simulated values for each hour, we then calculate the closeout costs in each simulated hour in the distribution – i.e.,$Y_i = max(LMP - K + \varepsilon_i, o)$. Having calculated the closeout cost for each hour in the distribution, we then estimate the mean of all simulated Y_i's in each hour to obtain the expected closeout costs in that hour, $\overline{Y_t}$.

Steps 1 to 2 provide a point estimate for *(RT LMP - K)*, while steps 3 to 5 account for the impact of the asymmetry in the closeout costs of the DA energy option on the expected closeout costs. That is, because the closeout cost is the maximum of *(RT LMP - K)* and zero (i.e., $max(LMP^{RT} - K, 0)$), there is a positive closeout cost only when the RT LMP exceeds the strike price and no closeout cost when the RT LMP falls below (or is equal to) the strike price.

To illustrate this asymmetry, consider the following illustrative example shown in **Table 65**. Assume that the strike price is $40 per MWh and the model estimates that *(RT LMP - K)* is $5 per MWh, implying a RT LMP of $45 per MWh. Further, assume there is a 50% probability that the RT LMP is $10 per MWh lower than this expected RT value of $45 per MWh, and a 50% probability that the RT LMP is $10 per MWh higher. This uncertainty does not change the expected value – the average of *(RT LMP - K)* is still $5 per MWh even if there is a 50% probability the price is –$5 per MWh and 50% probability the price is $15 per MWh. However, this uncertainty has an asymmetric effect on the option closeout costs, as there is a 50% probability the closeout cost is $15 per MWh and a 50% probability the closeout cost is $0 per MWh, such that the average closeout cost is $7.50 per MWh, not $5 per MWh.

Table 65. Illustrative Example of Asymmetric Effect of Uncertainty on Option Closeout

	Case Probability	Fitted Value (RT LMP - K)	Realized (RT LMP - K)	Option Closeout Cost
Case 1	50%	$5.00	-$5.00	$0.00
Case 2	50%	$5.00	$15.00	$15.00
Expected Value			$5.00	$7.50

When sampling residuals from the estimated model, we restrict the sample to residuals from that historical year. The model is fit to winter months only (December, January, and February) when estimating offer prices for the winter month analyses. For the non-winter months, the same model is fit to each nine month period comprising the two non-winter seasons. Additionally, for the non-winter cases offers are modeled separately for each season (spring, summer, and fall), to account for seasonal differences.

2. Approach to Estimating a DA Risk Premium

The approach taken to estimating a risk premium builds off the observation that the same risk preferences underlying risk premiums for derivatives traded in electricity markets should underlie risk premiums for DA energy options.[89] Thus, while there is limited market information on energy options, electricity forwards (e.g., a DA energy) are commonly traded in electricity markets, including New England's energy markets.[90]

Our approach accounts for a number of reasonable features of the risk premiums:

1. The risk premium reflects the (magnitude of) financial risk taken on when awarded a DA energy option. Thus, all else equal, the size of the risk premium increases with the variability of LMPs. Moreover, the risk premium may increase disproportionately with the level of financial risk assumed, if market participants are disproportionately averse to large losses. Thus, there could be a non-linear (convex) relationship between the risk premium and metrics of financial risk (e.g., the variability in returns).
2. The risk premium is larger for a resource with no energy inventory, as it faces a riskier, unhedged financial position.
3. The risk premium varies the resource's marginal cost of supplying energy, as it bounds the potential loss to (*MC* – *K*), providing a partial hedge on the DA energy option settlement risk.
4. The risk premium could be negative for resources for which the DA energy option lowers financial risk (e.g., if the resource has low *MC* relative to *K*).
5. The risk premium will depend on operational and intertemporal factors that prevent physical energy inventory from perfectly hedging financial risks.

DA energy option risk premiums are estimated using the following equation for unit *j* at time *t*:

89 Because the DA energy options will not be a traded product, but cleared through a market with fixed demand, and because the DA energy options are real options that cannot be replicated through existing financial markets (i.e., they are not spanned), conventional derivative pricing models are not appropriate to determining market participant bids to supply the DA energy options (e.g., see Cochrane, John and Jesus Saa-Requejo, 1999, "Beyond Arbitrage: Good-Deal Asset Price Bounds in Incomplete Markets.")

90 Prior research shows that risk premiums for day-ahead positions vary with multiple factors, particularly expected RT price variability and skewness. Observed risk premiums reflect an equilibrium outcome in which both buyers and sellers may desire to mitigate the risk of real-time energy market sales. Jacobs, Li and Pirrong (2017), for example, find that the equilibrium risk premium, reflecting both seller and buyer premiums, is 1% to 2%, with larger values in more volatile winter periods, while Bunn and Chen (2013) find Great Britain winter premiums are 7.2% for on-peak and 4.8% for off-peak, while summer premiums are –1.3% for on-peak and –1.0% for off-peak. We are not aware of empirical research that has performed such empirical analysis for electricity options. Bessimbinder, Hendrik and Michael Lemmon, "Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets"; Bunn, Derek and Dipeng Chen, 2013, "The forward premium in electricity futures," Journal of Empirical Finance, 23: 173-186.; Cochrane, John and Jesus Saa-Requejo, 1999; and Jacobs, Kris, Yu Li, and Craig Pirrong, 2017, "Supply, Demand, and Risk Premiums in Electricity Markets."

$$r_{o,j,t} = r_f * \frac{R_t}{C_t} * \left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma} * p_j$$

Where:

- $r_{o,t}$ is the option risk premium for hour t
- r_f is the average day-ahead unhedged forward risk premium for hour *t*, assumed to be 0.015 (i.e., a 1.5% risk premium)
- R_t is the (expected) real-time price, estimated as the day-ahead price for hour t
- C_t is the (expected) call option price, estimated as the expected close out cost for hour t
- σ_o, σ_f is the standard deviation of margins earned for the option for either option or forward contract, measured for peak and off-peak hours[91]
- γ allows for a non-linear relationship between RT settlement risk (variability) and risk premium, and is assumed to be 1 (i.e., no non-linear relationship is assumed, at present)
- p is a unit-specific adjustment to account for intertemporal constraints to the delivery of energy at *MC*, such as lost opportunities (revenues) due to start-up lead-time and operational risk

This formula starts with an estimate of the average day-ahead forward risk premium (in percentage terms), reflecting a range of market conditions. This risk premium is then adjusted for several factors:

- First, risk premiums are adjusted for the size of the option price relative to the forward price $\left(\frac{R_t}{C_t}\right)$. Within the finance literature, this is referred to as the assets delta. This adjustment accounts for the fact that an investor will require the same compensation to bear the same risk, irrespective of the instrument's price. Adjusting the risk premium for the relative prices ensures that this is the case.
- Second, the risk premium is adjusted to account for relative differences in the size of the risk, as measured by the standard deviation of the (negative) returns $\left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma}$.
- Third, the risk premium is adjusted for operational risks, including intertemporal constraints. The estimated risk (variability) of returns to the DA energy option assumes that the resource always delivers energy whenever LMP^{RT} > MC. However, in practice, within the real-time market, multiple factors may limit the extent to which a resource can supply energy. The adjustment factor, *p*, accounts for these factors.

Under this approach: several of the parameters, r_f, *p*, σ_f and γ, are constant across offers; two parameters, R_t and C_t, vary by hour; and one parameter, σ_o, varies across resources. Currently, the standard deviation of the option, σ_o, is calculated for each resource in each hour as a function of $\Delta = MC - K$ for peak and off-peak periods. Estimates of σ_o are based on the following function for peak and off-peak hours ($h = \{peak, offpeak\}$):

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[91] Assuming that σ_f reflects both negative and positive outcomes from a risk perspective, we focus on only the negative outcomes (i.e., outcomes that lead to a negative settlement versus the RT price) when measuring the risk premium. To do so, we assume the distribution of outcomes is symmetric, and simply divide σ_f by 2 under the assumption that one-half the variability (that associated with positive settlement) requires no risk premium.

$$\sigma_o = \beta_{0,h} + \beta_{1,h}\sqrt{\Delta}$$

Based on a linear regression where a separate linear equation is estimated for each LMP quartile for on- and off-peak hours. Estimates of $\beta_{0,i,p}$ and $\beta_{i,p}$ are estimated using historical data on market outcomes in New England's electricity markets.

With this risk premium adjustment, the bid will be the expected closeout cost adjusted for the risk premium – that is:

$$offer_{i,t} = CVC + PVC = E[max(0, RT\ LMP - K)] * (1 + r_{o,i,t}) = E[\cdot] * \left(1 + r_{f,t} * \frac{R_t}{C_t} * \frac{\sigma_o}{\sigma_f} * p_i\right)$$
$$= E[\cdot] * (1 + k_t \sigma_{o,i,t} * p_i) = E[\cdot] * \left(1 + (k_t\beta_0 + k_t\beta_1\sqrt{\Delta^*_{i,t}}) * p_i\right)$$

Where

- $k_t = r_{f,t} * \frac{R_t}{C_t \sigma_f}$
- $E[\cdot] = E[max(0, RT\ LMP - K)]$ is calculated through fitted regression and Monte Carlo analysis, as described above
- $\Delta^*_{i,t} = m_i MC_i - K$, where m_i is an additional adjustment parameter to account for unit-specific cost factors such as start-up costs and fuel cost risk

Table 66. Operational and Intertemporal Factors Accounted for in Risk Premium[92]

	Operational / Intertemporal Factors (p)			***Cost Factors (m)***		
	Performance Risk	Lead Time	Total	Fuel Cost Risk	Start-up Cost	Total
	[A]	[B]	[A]*[B]*[C]	D	E	[D]*[E]
Combustion Turbines						
Gas-only	1.05	1	1.05	1.5	1.45	2.18
Oil-only	1.05	1	1.05	1	1.45	1.45
Dual Fuel	1.05	1	1.05	1	1.45	1.45
Combined Cycle						
Gas-only	1.1	1.25	1.38	1.5	1.25	1.88
Oil-only	1.1	1.25	1.38	1	1.25	1.25
Dual Fuel	1.1	1.25	1.38	1	1.25	1.25
LNG Contract	1.1	1.25	1.38	1	1.25	1.25
Steam						
Oil-only	1.3	2	2.60	1	1.25	1.25
Dual Fuel	1.3	2	2.60	1	1.25	1.25

[92] To account for the reduced incidence of high natural gas price days in the non-winter months, gas-only Combustion Turbine and Combined Cycle units are modeled with a reduced "Fuel Cost Risk" multiplier of 1 in the non-winter months.

D. Posted Output Data

Along with this report, hourly results from the integrated production cost model for the winter Central Cases and the non-winter Cases have also been publically posted.[93] These data include market-clearing prices and quantities for DA and RT products (e.g. DA and RT energy, RT operating reserves, as well as DA AS products when applicable) in every hour of the modeled period. In addition, information on the day-ahead forecasted load is included for all cases, while various metrics related to the settlement of DA financial option products – such as the hourly real-time closeout price, and the hourly FER/EIR price – are included for ESI cases only.

For a given hour, these data present outcomes in the real-time market alongside that hour's corresponding day-ahead market outcomes. For example, hourly results listed for 12 PM on January 2nd, 2026 correspond to the real-time market solved in that hour and the day-ahead market solved on the prior day, for delivery the next day (i.e., the day-ahead market solved for delivery at 12 PM on January 2nd).

The quantities for DA and RT products reflect the total MW commitment across all resources in the New England region in a given hour. The clearing prices listed in these hourly results are the shadow price for the relevant product constraint, optimized over the entire New England fleet. For more information on how clearing prices for DA and RT products are set by the production cost model, please consult **Section III.3** of this report.

For ESI cases, shortages for GCR, and RER energy option products occur when the total hourly commitment does not satisfy the hourly requirements (2,400 MW and 1,200 MW, respectively). EIR shortages occur when the sum of EIR and DA generation together in a given hour is less than the forecasted load quantity.

93 This data is available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_e_preliminary_esi_impact_analysis_hourly_model_outputs.xlsx.