Energy Security Improvements: Creating Energy Options for New England

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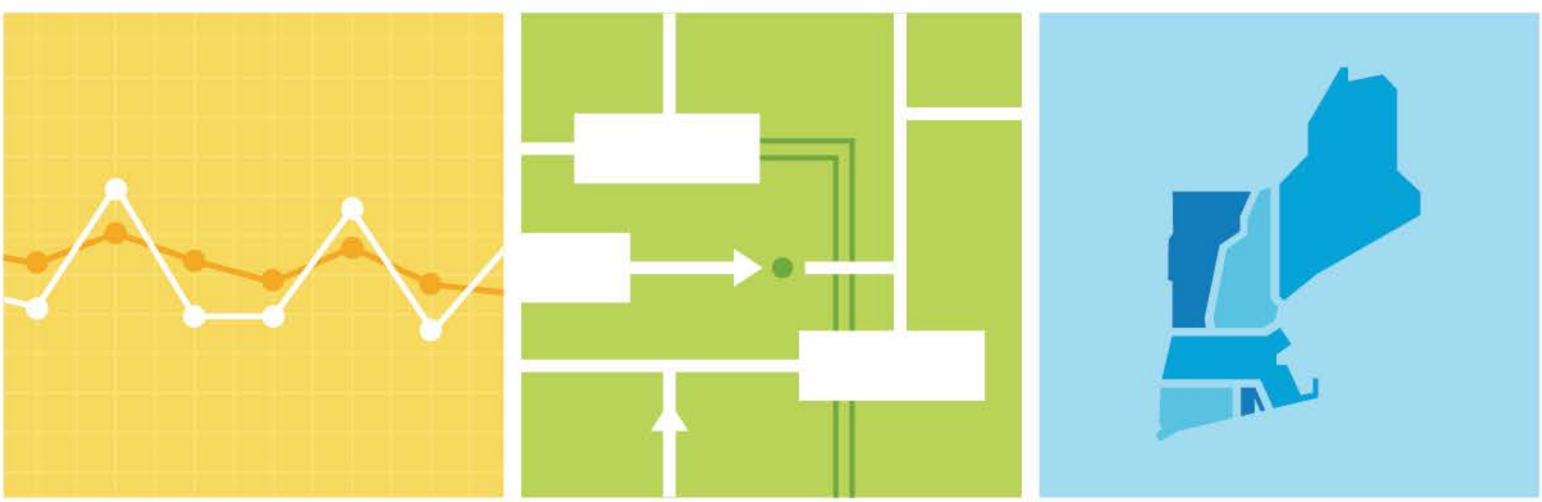

Revision note

This release includes typographic and other non-substantive revisions to the April 15, 2020 version of this report.

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This paper describes in detail the changes to the ISO New England Transmission, Markets and Services Tariff ("Tariff") being filed on April 15, 2020 to address potential energy security problems in New England. These changes comply with the Federal Energy Regulatory Commission's 2018 directive that ISO New England submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[1] *This paper explains the underlying causes of these problems and how the improvements to the market design will address them.*

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[1] Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines, 164 FERC ¶ 61,003 at P 2 (2018) ("July 2, 2018 Order").

Energy Security Improvements: Creating Energy Options for New England

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1. Introduction and Summary

The electric power system in New England is undergoing a major transition. The owners of traditional power plants – nuclear, coal, and oil-fired – are permanently shuttering many of these stations due to economic and environmental pressures.[2] The majority of the region's electricity, both currently and for the foreseeable future, is likely to come from newer, more efficient natural-gas-fired generation and an array of renewable energy technologies, such as solar and wind.

This evolution comports well with the New England states' goals for a cleaner, greener regional power grid, yet it also presents new challenges. Both renewable and natural gas-based generation technologies rely on the "just-in-time" delivery of their energy sources. Solar- and wind-based power inherently vary with the weather. Less obviously, and of greater concern presently, is the just-in-time delivery of natural gas across interstate pipelines to the region's generating stations. During cold winter conditions, these pipelines rapidly reach capacity and are unable to fuel many of New England's power plants.[3]

Given the power system's increasing reliance on these just-in-time resources and the region's constrained fuel delivery infrastructure, ISO New England Inc. (ISO) is concerned that there may be insufficient energy available to the New England power system to satisfy electricity demand during cold winter conditions. While there has been no loss of load attributable to insufficient energy supplies to date, the ISO is concerned that industry trends will increase this risk over time unless proactive solutions are developed.[4]

In practice, reducing the risks that arise in a power system increasingly reliant on just-in-time energy sources requires additional sources of energy supply (or reductions in demand) when gas pipelines are most constrained, when renewable resources experience adverse weather, or both. Additional energy supply (specifically, fuel) arrangements can enable existing fossil-fired generating stations to perform reliably during such conditions. Examples include arrangements by natural gas-fired generators to procure and maintain liquefied natural gas (LNG) inventories at existing LNG facilities in the Northeast (for use when the interstate pipelines are constrained during winter), and making advance arrangements for fuel oil supplies to be promptly replenished during winter at the region's dual-fuel (oil and gas) and oil-based power plants. Over the longer term, a broader array of capital investments may ultimately produce cost-effective alternatives. These may include greater price-sensitive demand participation in the wholesale markets, local "satellite" LNG storage facilities near

[2] *See* ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids, and Substitution Auction Demand Bids, available at https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx (showing all pending and retired capacity resources from 2013 through 2024).

[3] *See* Energy Security Improvements: Market Solutions for New England, Speaker materials of Matt White and Chris Parent, ISO New England, at the ISO New England Fuel Security Noticed Meeting, FERC Docket No. EL18-182-000 (filed July 15, 2019), at Slides 9-11.

[4] *See, e.g.*, *Winter Energy Security Improvements* memorandum from the ISO to the NEPOOL Markets Committee, dated September 6, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/09/a9_iso_memo_winter_energy_security_improvements.pdf, at pages 2-3.

generation stations, and innovative electricity storage technologies (like grid-scale batteries) that can smooth out the intermittency of renewable energy resources.

Unfortunately, the existing energy market structures do not properly incent such investments. The competitive power sector's willingness to undertake any of these reliability-enhancing-but-costly endeavors depends on their expected return on the investment. As discussed in the next section, however, the very act of making those costly investments can dramatically reduce (or eliminate) the expected return on that investment. As a result, investments that would both improve reliability and be cost-effective from a societal perspective are not cost-effective for the competitive suppliers making these decisions.

Bearing this out, the region's competitive power sector has made little progress with these reliability-enhancing investments. In recent winters, few natural-gas fired generators have made advance arrangements for LNG inventories in New England; and by some measures, the generation fleet's fuel oil inventories for winter power generation are declining over time, due to both economic factors and emissions restrictions.[5]

Addressing these very issues, the Federal Energy Regulatory Commission (Commission) in 2018 directed the ISO to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[6] That directive arose amidst a contentious regulatory process involving shorter-term, non-market actions to bolster the region's fuel supplies by delaying the retirement of the large Mystic Generating Station near Boston, Massachusetts. Expressing a clear preference for a different path forward, the Commission reaffirmed its "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates," and expectations for the ISO "to develop longer-term market solutions."[7]

To that end, after addressing the problems and causes of these energy security concerns, this paper describes in detail the market-based solutions (referred to herein as the "Energy Security Improvements") that the ISO has developed and vetted with regional stakeholders. In short, while the power system's growing reliance on technologies with just-in-time energy sources poses new challenges, we believe these challenges have sensible solutions. Further, we readily agree with the Commission's affirmation that these challenges are most appropriately addressed through market mechanisms. As the technologies comprising New England's power grid continue to rapidly evolve, harnessing the forces of competition will provide the most cost-effective long-term solutions.

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[5] *See, e.g.*, *Responses to Questions Relative to Energy Security Proposal* memorandum from the ISO to Joint Requestors, dated March 21, 2019 (revised), available at https://www.iso-ne.com/static-assets/documents/2019/01/a7_iso_memo_containing_responses_to_joint_requestors_questions_on_energy_security_proposal.pdf, at pages 2-5.

[6] July 2, 2018 Order at P 2.

[7] July 2, 2018 Order at PP 53, 54.

1.1 Problems and Causes

To facilitate analysis of the region's energy security concerns and potential solutions, this paper begins with a deeper examination of the underlying problems and their root causes. Our focus is whether the ISO-administered wholesale electricity markets – which were not originally designed for the challenges that just-in-time generation technologies have wrought – provide adequate financial incentives for resource owners to make additional investments in energy supply arrangements that would be cost-effective and benefit the power system at times of heightened risk.

Our central conclusion is that, in many situations, the answer is no. Even when such energy supply arrangements would be cost-effective from society's standpoint as a means to reduce reliability risks, the ISO's current suite of market products do not provide sufficient financial incentives for market participants to undertake them. The root cause is logical enough. Making these discrete investments entails up-front costs to the generator. But if those investments meaningfully reduce the risk of electricity supply shortages (and therefore the risk of high prices), then they will also reduce the energy market price the generator receives. The value that society places on the generator's energy supply (*e.g.*, fuel) arrangements is based on the high price society *avoids* as a result of the investment. However, the value the generator places on the same arrangement is based on the lower price that it *receives* in the energy market with the investment. This divergence between the social and private benefit of the investment represents a significant *misaligned incentives* problem.

In effect, given how New England's power system has evolved, generation owners face a "no-win" situation: If a generator *does not* make, for example, a costly additional fuel supply arrangement, then when the region's gas pipelines are tightly constrained and renewables' output is low, high real-time wholesale energy market prices will prevail. These high prices cost consumers dearly, but do not immediately benefit the generator if it lacks fuel to operate (because it did not make the necessary fuel supply arrangements). Those high market price signals normally motivate widespread investment to profit in such circumstances. And yet, if the generator *does* invest in more robust fuel supply arrangements – at least, to a level that meaningfully reduces the system's energy supply risk – then the investment may obviate the market's high energy price, undermining the generator's expected return on the investment. Given these misaligned incentives, and that nearly any investment in additional energy supply arrangements tends to entail significant costs up-front, it is no surprise that few generation owners perceive adequate incentives to undertake them.

To explore this problem in detail, this paper provides a series of numerical examples. These are intended to help make the nature of the problem, and the conditions on which is rests, readily apparent. The bottom line is that investing in more robust energy supply (*e.g.,* fuel) arrangements may often be beneficial and cost-effective for the system, but not financially viable for individual generators in the ISO's present energy market construct.

Deconstructing this problem in detail, as we do in this paper, has a useful summary implication: the suite of products in the ISO-administered energy markets is incomplete. Their current form and associated ancillary service products were designed more than fifteen years ago, well before just-in-time energy powered the majority of New England's generation. In that earlier era, capacity supply was a constraining reliability concern. Specifically, as long as the system had sufficient operable capacity committed each day, another increment of energy demand could be satisfied by dispatching up the next generator. In today's environment, however, we do not face a capacity shortfall problem (indeed, the system is awash in capacity). We, instead, face an *energy security* problem due to the constraints and uncertainties that limit the region's energy supply for power production.

► **Essential Reliability Services for Managing Energy Uncertainty.** In New England, most resources that clear in the day-ahead energy market successfully operate during the hours for which they receive a day-ahead energy schedule. That has been true since the competitive markets' inception more than twenty years ago, and remains true today.

Consider, however, the situation when a large resource clears day-ahead, but is subsequently unable to operate for an extended (multi-hour or multi-day) duration. This creates an unanticipated 'energy gap' in the day's operating plan. The replacement energy to fill that gap must come from other resources operating above their day-ahead awards (or resources that did not receive a day-ahead award).

With the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, however, those replacement resources – which did not expect to run – may not be able to operate unless they invested in robust energy (*e.g.,* fuel) supply arrangements in advance of the operating day. Yet in today's market construct, it is generally unprofitable to incur the costs of procuring fuel to cover days for which a resource did not expect to operate – or to be paid.

In practice, the ISO relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, for the essential reliability services necessary to fill such 'energy gaps.' In concrete terms, these capabilities fall in three operational categories:

- resources capable of providing energy to cover the gap when the total energy supply cleared in the day-ahead market from physical resources (*e.g.,* generation and net imports into New England) is insufficient to serve the forecast electricity demand for the next operating day;

- resources capable of providing fast-start / fast-ramping contingency response, which enable the system to promptly close the gap between energy supply and demand following an unanticipated supply loss (consistent with the timeframes established in applicable reliability standards); and

- resources capable of providing replacement energy, for the balance of the operating day, when and as needed to restore the contingency reserve resources to reserve status and to serve an unanticipated increase in energy demand.

As discussed in detail in later sections, we distinguish these three categories insofar as they involve conceptually distinct services and capabilities. In particular, they require different resource capabilities in order to cost-effectively address potential energy gaps that arise on, and persist for, different timeframes.

At present, the ISO does not procure or compensate for these types of ancillary service capabilities on a day-ahead timeframe. That may have been reasonable in the past, when generators without day-ahead energy schedules characteristically had large, ready stockpiles with which to fuel an unexpected, extended run whenever an energy gap arose. But, as noted previously, those generators are retiring, and many that remain are at risk of future retirement.

Thus, it is important to improve today's energy market construct so that the future resource mix will invest in energy supply arrangements and technologies that ensure these essential reliability services – and the requisite resource capabilities – remain available to the power system each operating day.

1.2 Solutions

The second portion of this paper introduces market design improvements to address these problems. The overall design is based on a familiar set of energy and ancillary service concepts. Broadly, these changes expand the existing suite of energy and ancillary service products in the ISO-administered markets, in order to address – reliably and cost-effectively – the uncertainties and supply limitations inherent to a power system becoming more and more reliant on just-in-time energy technologies.

Building upon the region's competitive wholesale electricity structure, the ISO intends to create several new, voluntary ancillary services in the day-ahead market that provide, and compensate for, the flexibility of energy 'on demand' to manage uncertainties each operating day. These services will help signal, through transparent market prices, the costs of operating a reliable power system as the profile of resources comprising the New England fleet continues to evolve. And they will help ensure that the system is prepared for, and has the capabilities to manage, a range of uncertainties in a power system increasingly reliant on just-in-time technologies.

► **New Day-Ahead Ancillary Services as Call Options on Energy.** The changes described herein will formalize the foregoing three categories of operational needs (listed in Section 1.1 above) into specific ancillary service capabilities and allow resources to compete to provide those capabilities in the ISO's day-ahead markets. Offers to provide those ancillary services will be voluntary, and awards compensated at uniform, transparent, product-specific market prices. At a high level, a day-ahead seller of those ancillary services is providing the ISO with an on-demand "call" on its energy during the operating day, with different lead times applicable to the different ancillary service products.

To procure these services cost-effectively, the award of these ancillary services will be co-optimized (that is, simultaneously cleared) with all participants' energy supply and demand awards in the day-ahead market. That co-optimization process ensures, by design, that the clearing prices for energy and each ancillary service incorporate the (marginal) suppliers' opportunity costs of not receiving an award for a different day-ahead product. It also means that the day-ahead prices for energy will commonly incorporate the clearing prices for the ancillary services as well. As a result of procuring multiple new products in the day-ahead market, the day-ahead market's total energy compensation to suppliers will also be higher than under the current rules.

The new co-optimized market design also adds a new component to the day-ahead market's energy compensation to supply resources – in addition to new ancillary service revenue. This new component – the 'forecast energy requirement' – will provide greater revenue to resources with day-ahead obligations to supply energy and that contribute to a reliable next-day operating plan for the power system, strengthening their incentives to invest in additional energy supply arrangements.

For the three new ancillary services, a central design feature is their settlement. Consistent with their value as a call option on energy during the operating day, a day-ahead ancillary obligation will be settled as a proper call option on real-time energy. That is a familiar, standard multi-settlement rule used in a wide variety of commodity markets to manage uncertainty. Moreover, it functions well in concert with the existing day-ahead energy market's two-settlement design. The second (real-time) settlement is slightly different for day-ahead energy and for ancillary service positions, however, reflecting that the former is a forward sale (or purchase) of real-time energy and the latter is call option on real-time energy.

Importantly, an option settlement design creates strong new incentives for sellers of these ancillary services to ensure they have the physical ability (including fuel) to cover their obligations the next day. This is because a resource that commits to providing an ancillary service will face a steep financial consequence if the real-time energy price is high and the resource does not perform. Using a series of numerical examples, this paper will explain how this approach provides stronger incentives than the existing market design for resources to incur the costs of additional energy supply arrangements. At the same time, resource owners will receive new day-ahead compensation to cover their costs of additional energy supply arrangements, even if it turns out that their resources are not needed for the system to operate reliably on the next day.

These product design and settlement features fundamentally change the incentives that suppliers face. From a commercial standpoint, it will become profitable for the resources that the ISO relies on for these ancillary services to incur the costs of maintaining more reliable energy supply arrangements, when such arrangements are cost-effective from the standpoint of the system overall – helping ensure they *could* perform if needed to fill an energy gap, even on days they did not expect to operate.

1.3 Benefits

As noted above, in 2018 the Commission directed the ISO to develop and file longer-term market solutions "reflecting improvements to its market design to better address regional fuel security concerns."[8] Furthermore, the Commission emphasized its "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates."[9] Consistent with these directives, the significant benefits of the Energy Security Improvements fall into three broad categories. First and foremost, these improvements achieve the

[8] July 2, 2018 Order at P 2.

[9] July 2, 2018 Order at P 53.

Commission's requirement to improve fuel security for the region. Second, they do so in a fully market-based manner. Third, the Energy Security Improvements have other important benefits beyond energy security. We summarize each of these benefits here.

1.3.1 The Energy Security Improvements Will Improve Fuel Security in New England, as Directed by the Commission, by Solving the Misaligned Incentives Problem

The ISO is confident that the Energy Security Improvements will enhance fuel security in New England, and will promote more robust energy supply arrangements broadly, in a fuel- and technology-neutral manner. They will do so in three distinct ways:

First, the Energy Security Improvements will procure new ancillary services in the day-ahead market that will more completely reflect the daily operational needs of the system. The new design will formalize, through the market, the option to call upon 3,000 to 5,000 MW of reserves each day to help ensure reliable operations. These are capabilities that the ISO currently relies on, but that are not adequately compensated for such service under the current rules. Recognizing these capabilities in the Day-Ahead Energy Market will ensure that the system is prepared in advance to respond when the region faces the types of real-time stressed system conditions that, in the past, have created concerns over fuel security.

Second, the Energy Security Improvements will provide more accurate and stronger price signals to suppliers during tightening (limited supply) conditions, including conditions arising from the region's fuel infrastructure limitations.[10] These day-ahead price signals will provide an early warning that market conditions are tightening when there is not yet an actual scarcity condition (that is, a real-time shortage of energy or reserves). That will provide suppliers with commensurately increasing incentives to invest in additional energy supply arrangements so they are prepared when challenging operating conditions do arise, and it appropriately compensates those suppliers for their efficiency and flexibility.

Third, the Energy Security Improvement create new financial consequences for resources that offer to provide these essential capabilities but then do not perform during tight market conditions. Resources selling these new ancillary services will be financially responsible for not supplying energy in real-time, with the market design specifying that the cost of not supplying energy be based on the real-time energy price (which can exceed $3,800 per MWh during periods of scarcity).[11]

Together, these three inter-woven improvements will provide additional incentives, and the compensation (and potential consequences) necessary, for resources to bolster their fuel and

[10] In this regard, Energy Security Improvements will operate in tandem with other recent enhancements that enable the markets and participants to better respond to changes in system conditions, including a mechanism to better enable fuel-constrained resources to reflect their (opportunity) costs in energy market offers, and improvements to the forward-looking (21-day) information provided to market participants about expected energy supply conditions.

[11] It is worth noting that the Energy Security Improvements will not operate in a vacuum; rather, the combination of reserve shortage pricing in the energy market and the fully phased-in "Pay For Performance" penalty rate in the capacity market will create an effective energy price that can exceed $9,000 per MWh during real-time scarcity conditions.

energy-source arrangements. In this manner, the Energy Security Improvements will directly address the misaligned incentives problem mentioned previously, by meaningfully strengthening incentives for effective participant-driven supply-chain management and reliable fuel (or other input energy) supply arrangements by resource owners. Importantly, the ISO is not aware of another market design that could achieve the same outcome.

The likely efficacy of the Energy Security Improvements is evident in the results of the Impact Assessment work performed by the Analysis Group, Inc. Overall, that detailed study finds it profitable for many resources to maintain greater fuel inventories under the Energy Security Improvements design, relative to the current market rules. For example, in Section IV.A.1.c of the Impact Assessment, the Analysis Group finds that the new revenue streams introduced by the Energy Security Improvements are sufficient to incent significantly greater oil inventories (and replenishments thereof) across a range of resource types and market conditions.[12] Notably, Tables 11 through 13 of the report show that when resources increase their oil inventory during the winter in response to the new revenue streams, they will – in nearly all scenarios studied – earn significant returns from such investments.[13]

Similarly, Section IV.A.1.d of the assessment shows that the Energy Security Improvements will tend to increase incentives for natural gas resources to consider entering into winter peaking gas contracts. While the assessment does not definitively determine the extent to which the changes would incent generators to sign such contracts, it finds that the returns associated with such contracts are greater with the Energy Security Improvements than under the current market rules during stressed winter cases, and therefore concludes that the introduction of these improvements increases this likelihood relative to current market rules.[14]

More broadly, the full spectrum of the Analysis Group's results supporting the efficacy of the Energy Security Improvements is exactly what one would expect from an economically sound market design that better addresses the region's fuel security concerns.

1.3.2 The Energy Security Improvements are Fully Market-Based, with Many Attendant Benefits

The Energy Security Improvements will improve the bulk power system's energy security by using a sensible market approach that signals, through transparent, day-ahead prices, the costs of satisfying the region's electricity needs at all times, including during periods of severely stressed system conditions. When *fuel* scarcity is properly priced – that is, through its impact on *energy and reserves* scarcity – the wholesale electricity markets will appropriately compensate all resources that contribute to the system's reliability. Consistent with sound market design, they will also incent

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[12] *See Energy Security Improvements Impact Assessment* by Analysis Group, Inc., provided as Attachment C to the Energy Security Improvements filing ("Impact Assessment"), dated April 2020, at Section IV.A.1.c.

[13] *See* Impact Assessment at Section IV.A.1.c, Tables 11-13.

[14] *See* Impact Assessment at Section IV.A.1.d and Table 15.

cost-effective investments by resources that can provide the greatest reliability benefits to consumers. The many benefits of this market-based approach include:

► **Fuel and Technology Neutrality.** Centrally, the Energy Security Improvements are focused on promoting reliable electric energy and ancillary services *output* – and are, by design, fuel and technology neutral. The design rewards resources, of any technology or fuel type, that acquire a day-ahead commitment to supply energy or ancillary services and thereby contribute to the system's daily reliability requirements – including renewable resources, traditional and emerging storage technologies, and traditional fossil-fueled generators. In short, these improvements will strengthen the financial incentives for generation owners to undertake more robust energy supply arrangements, when cost-effective, while not proscribing what form those supply arrangements may take.

► **Cost Effectiveness.** Providing incentives through the market for electric energy and reserves (again, paying for energy outputs, not fuel inputs) will help to ensure that the Energy Security Improvements will address the region's fuel security concerns in a cost-effective manner. Owners of resources of any type or technology will have strong incentives to firm-up their fuel or other energy supply sources, through whatever means they find most cost-effective, to support their day-ahead market obligations. By contrast, non-market mechanisms (such as direct subsidies to selected generators to procure additional fuel) benefit only those selected resource owners, providing no incentives to other resources – or to potential new technologies, such as storage – that may help comprise cost-effective, long-term solutions.

► **Transparency.** Because these new incentives will be provided through a market-based mechanism, they are signaled through market prices visible to all. In this way, the Energy Security Improvements extend a fundamental benefit of markets – their price transparency. The visibility of the market's strengthened resource incentives will encourage more efficient investments in energy supply arrangements than the current markets – investments that seek to reduce reliability risks in New England's increasingly energy-constrained power system.

► **Consistency with Existing Market Design.** The Energy Security Improvements logically extend the concepts that underlie the region's s longstanding energy markets. The new products and services will work smoothly with the existing day-ahead and real-time markets, filling the gap in the current markets' product suite by providing new compensation for resource capabilities not presently remunerated in the day-ahead market.

► **Fairness and Innovation.** The Energy Security Improvements will compensate all technologies capable of providing energy or any of the new ancillary services, creating a level playing field for market participants. And because no capable technology is excluded, this design should foster innovation, as participants explore the best technologies or other means to capitalize on the new products.

► **Risk-Responsiveness.** Using a market-based approach to address these issues will ensure that the costs of improving the region's energy security are related to the risks. If the region's energy security risks are not realized in future years – perhaps because they are meaningfully reduced through different policies outside the ISO-administered markets (say, through much greater renewable energy production and storage in future years) – then providing these new products and services would have lower costs for sellers, and procuring these products and services would have lower costs for consumers. That 'risk-responsive' aspect of the overall design prevents locking consumers into new multi-year obligations that might prove both expensive and unnecessary, as New England's power system continues to evolve.

1.3.3 The Energy Security Improvements Have Benefits Beyond Energy Security

The Energy Security Improvements will also have several benefits not directly related to energy security. While those "co-benefits" are not the immediate objective of this filing, they will enhance both the benefits of New England's competitive wholesale electricity markets and the ISO's ability to manage the region's rapidly evolving power system reliably.

For one, the Energy Security Improvements to the market design have important price formation benefits. The ISO presently relies upon a variety of unpriced and "out-of-market" actions in the energy market to ensure the system can satisfy certain reliability standards – all because the existing market design is incomplete. That is, the current design lacks prices for specific day-ahead ancillary services needed to ensure that the system has a next-day operating plan that satisfies the applicable reliability standards and requirements (as discussed in more detail in Section 2.6.1 below). In contrast, the Energy Security Improvements filed here will use transparent markets – with well-defined market products, transparent market-clearing prices, and competitively-determined awards – to ensure that the system has a next-day operating plan that satisfies these standards and requirements.

This is a significant benefit, as it helps to ensure that competitive market prices appropriately convey the costs of operating a reliable power system. That, in essence, is the central goal of price formation improvements generally. And in this way, the Energy Security Improvements advance the broader Commission-approved corporate mission of the ISO to "provide an opportunity for a participant to receive compensation through the market for a service it provides in a manner consistent with proper standards of reliability."[15]

The Energy Security Improvements are also tightly coupled to existing reliability standards, and do not purport to create a new standard for fuel security. The new design will ensure that existing reliability standards – as set forth in current North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") standards, as well in the ISO's Operating Procedures – are met, in a cost-effective manner. These standards are described in detail in the Testimony of Peter T. Brandien, Vice President of System Operations and Markets Administration, provided as an attachment to the Energy Security Improvements filing.[16] In that testimony, Mr. Brandien explains how the Energy Security Improvements align with the operational capabilities

[15] Tariff Section I.3(b).

[16] *See* Testimony of Peter Brandien, Vice President of System Operations and Market Administration of the ISO, provided as Attachment A to the Energy Security Improvements filing ("Brandien Testimony"), at pp. 6-17.

needed to ensure that the ISO's daily operating plans comply with those existing reliability standards.[17]

Finally, the Energy Security Improvements will also help the ISO to manage the rapid growth of renewable resources participating in the New England markets.[18] As mentioned earlier, the New England region is becoming increasingly dependent on intermittent and renewable resources with "just-in-time" delivery of their input energy sources (sun and wind). Energy production from such resources is dependent on the weather, and is therefore uncertain day-to-day. The Energy Security Improvements will help the system to manage the uncertainty over the next-day energy production of these resources. Specifically, the new ancillary service products being introduced with this filing are well-suited for addressing operational uncertainties that affect generators' input energy sources, whether they arise from adverse weather or constrained fuel supply conditions. Furthermore, the new market design improvements will fundamentally reward resource flexibility that helps the ISO to manage, and prepare for, energy supply uncertainties during the operating day.

* * *

In sum, the Energy Security Improvements will strengthen financial incentives for generators to undertake more robust supply arrangements, when cost-effective, while not proscribing what form those supply arrangements may take; reward resource flexibility that helps to manage, and prepare for, energy supply uncertainties during the operating day, given the increasingly just-in-time nature of the power system; and enable New England's competitive markets to better signal, through transparent prices, the costs of operating a reliable power system as it continues to evolve.

The balance of this paper provides further perspective on problems and causes, the specific goals of the new ancillary services, and explains in detail how they will work. In Section 2, we examine the problems and their root causes in detail, and illustrate the challenges they present with a series of numerical examples. In Section 3, we summarize the design objectives and principles that guide the ISO's development of market improvements to address these challenges. In Section 4, we delve into the new energy option design for the day-ahead markets and its settlement. In Section 5, we show how this energy option design solves the misaligned incentives problem and directly incents greater expenditure on cost-effective energy supply arrangements, using a series of numerical examples. In Sections 6 and 7, we detail each specific new ancillary service product and their impact on day-ahead energy market prices, covering specific rationales, pricing, clearing, relations to reliability standards, and providing additional numerical examples to illustrate market outcomes. Section 8 concludes.

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[17] *See* Brandien Testimony at pp. 26-30.

[18] *See* Energy Security Improvements: Market Solutions for New England, Speaker materials of Matt White and Chris Parent, ISO New England, at the ISO New England Fuel Security Noticed Meeting, FERC Docket No. EL18-182-000 (filed July 15, 2019), at Slide 6.

2. Problems and Causes

In this section, we provide a deeper diagnosis of the problems and causes underlying the ISO's energy security concerns. To lend clarity to these concerns, we identify several specific adverse consequences that arise under the current market design – consequences that may become more significant in the future, as the number of resources with just-in-time energy sources grows. The analysis of these consequences, and their root causes, has guided the development of the market-based solutions presented in Sections 4-7 of this paper.

2.1 Focusing Deeper: Three Specific Problems

Energy security is a broad term subject to a myriad of competing interpretations. To provide focus, we constructively frame the power system's emerging energy supply risks in terms of three specific problems, enumerated below. These have interrelated market and operational components, and adversely affect both the efficiency and reliability of New England's power system.

Problem 1: **Misaligned Incentives.** Market participants whose resources face production uncertainty may have inefficiently low incentives to invest in additional energy supply arrangements, even though such arrangements would be cost-effective from society's standpoint as a means to reduce reliability risks.

Problem 2: **Operational Uncertainties.** There may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss, particularly during cold weather conditions.

Problem 3: **Insufficient Day-Ahead Scheduling.** New England's current energy-only day-ahead market commonly schedules (that is, clears) insufficient energy to meet the ISO's forecast load for the next operating day.

The first of these problems is one of misaligned incentives. Investing in more robust energy supply (*e.g.,* fuel) arrangements may not be financially viable for individual generators in today's market construct, yet can be beneficial and cost-effective for the system. This has both efficiency and potential reliability consequences. We address this problem in detail first.

The second of these problems relates to operational 'energy gap' situations. With the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, generating resources that do not expect to run the next day (*i.e.,* that do not receive an award in the day-ahead market) may not have sufficient energy to operate – unless they made costly fuel supply arrangements in advance. These concerns are heightened by the fact that the ISO currently relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, to fill any energy gaps that arise during the operating day.

The third of these problems is the potential imbalance between the day-ahead market's outcomes and the system's requirements for a reliable next-day operating plan. The ISO's markets presently enable buyers to procure energy in the day-ahead market, yet also provides them with the "free" option to wait and reveal their demand only in real-time. That option is not costless to the system, however. When market participants procure less energy in the day-ahead market than the ISO's forecast energy demand for the next operating day, the system must cover that gap by scheduling additional resources (or additional output beyond day-ahead cleared resources' energy schedules) after the day-ahead market. That out-of-market reliability process ensures that the system can cover the forecast energy demand, but does not transparently signal the costs of those post-market actions. Nor does it provide the same compensation and incentives for generators to arrange fuel that the day-ahead market provides, contributing to the region's fuel security concerns.

It is important to note that these three specific problems are interrelated. Problem 1, misaligned incentives, is the foundational issue underlying the energy security issues addressed here. As such, it will receive the most attention in the balance of this Section 2. Problems 2 and 3, operational uncertainties and insufficient day-ahead scheduling, are specific manifestations of Problem 1 (though they both have other root causes as well). We discuss each of these three problems in succession below, in order to provide clear explanations of their distinct causes and consequences.

2.2 Problem 1: Misaligned Incentives for Energy Supply Arrangements

This section examines Problem 1, focusing on existing market incentives. Specifically, we address why the ISO-administered wholesale electricity markets, in their current form, may not provide sufficient incentives for resource owners to make additional investments in energy supply arrangements – even when such investments would reduce potential reliability risks and be cost-effective for the system.

At a high level, investing in additional energy supply (*i.e.,* fuel) arrangements that meaningfully reduce the risk of shortages (and therefore the risk of high electricity prices) entails up-front costs to a generator. Yet those investments, if they meaningfully reduce that risk, will also reduce the energy market price the generator receives. The value that society places on the energy supply arrangement is based on the high price it *avoids* with the investment. However, the value the generator places on the same arrangement is based on the lower price it *receives* in the energy market with the investment. This value difference, in turn, results in a divergence between the social and private benefit of the investment – a situation we call a *misaligned incentives* problem.

In short, the misaligned incentives problem results in too little private investment in energy supply arrangements under the existing markets' incentives than is desirable from society's standpoint. And, fundamentally, to provide a long-term market solution to the region's fuel security concerns, the market design must now address that misaligned incentives problem.

To explain this problem and its root causes more precisely, a simple numerical example is helpful.

2.2.1 Example 1: One Generator

This example considers the fuel decision for a generator without a day-ahead market award. It faces an unlikely possibility that demand may be high enough for it to operate the next day, and must decide now whether or not to incur the cost of arranging fuel.

We simplify as much as possible here to focus on the essentials: A case where the cost of arranging fuel is lower than society's benefit (*i.e.*, the system's expected cost savings) from it, but that cost nonetheless exceeds the generator's expected profit. As a result, the competitive generator's rational decision is not to arrange fuel in advance of the operating day, even though society would be better off if it did.

► **Assumptions.** Consider a generator with 1 megawatt (MW) of capacity that faces uncertainty over whether or not it will operate the next day. The generator will be dispatched (if available) if demand is high, and not dispatched if demand is low. Assume there is a 20% chance of high demand, so the generator knows that it will most likely not operate. To simplify this example, we will reduce the time period in which the generator may operate (or not) to a single future hour and assume that the generator does not clear (*i.e.,* is not scheduled) in the day-ahead market.

The generator's costs depend upon whether or not it arranges fuel in advance of the operating day. Arranging fuel entails an up-front cost, and an incremental cost if the fuel is consumed the next day. We assume that if the generator arranges fuel in advance of the operating day, then it incurs an up-front cost of $40 per MW-hour (MWh). By 'up-front cost', we mean that *if* the generator decides to arrange fuel in advance, it would incur the $40 cost *regardless* of whether or not it operates the next day. And then, *in addition*, it would incur a marginal cost of $70/MWh to operate – but that marginal cost is incurred only if it does indeed operate. We summarize these cost and demand assumptions in Table 2-1 below.

Table 2-1. Cost and Price Assumptions for Example 1

	With Advance Fuel			No Advance Fuel	
	High Demand	Low Demand		High Demand	Low Demand
Up-Front Cost of Advance Fuel	$ 40	$ 40		$ -	$ -
Marginal Cost	$ 70	n/a		n/a	n/a
Energy Price (LMP)	$ 120	$ 60		$ 400	$ 60
Demand Probability	20%	80%		20%	80%

If the generator arranges fuel in advance of the operating day and the demand is high, then it can produce at a marginal cost of $70/MWh and would be paid (in real-time) an LMP of $120/MWh. That's the 'good' scenario in this example, because it will have the lowest expected total cost (as explained presently). Importantly, we will assume that if the generator does *not* arrange fuel in advance, then it will not be able to acquire fuel the next day and will not be able to operate. In that scenario, if demand turns out to be high, the ISO would have to operate another, high-cost resource (at the margin) that would set a real-time LMP of $400/MWh. That's the 'bad' scenario, as it results in higher total costs than if the generator arranged fuel in advance.[19] Finally, assume if demand is

[19] Alternatively, one can interpret the $400/MWh cost as this generator's marginal cost if it must buy spot fuel intraday (on a really bad day), if it does not make advance fuel arrangements. Either interpretation will suffice for this example.

low then the LMP would be $60/MWh so the generator would not operate, as it would be out-of-merit.

These assumptions are intended to capture the practical realities that there are up-front costs of acquiring energy supplies in advance of an operating day, *in addition* to the (marginal) cost of using the fuel itself. The $40 up-front cost could be considered the retainer (per MWh) for an intraday-notice gas supply contract with an LNG terminal, and the $70/MWh cost as the incremental cost of calling for gas in order to run the next day if the generator is dispatched. Or, the up-front cost could be considered the generator's expense for oil transportation service to accelerate replenishment of oil inventories in advance of the operating day, without which the generator would be out of fuel and not be able to run at all. Or, for a generator that is an energy storage resource, the up-front cost may account for the cost it incurs to charge-up in advance of the operating day, in order to maintain on-demand energy in ready reserve during the operating day. And so on – the practical possibilities are many. The point here is simply that there are costs of arranging input energy (*i.e.,* fuel) supplies in advance, in addition to the marginal cost of using it to produce electric energy; and, if a generator decides not to incur the costs of arranging fuel in advance, then (with *some* probability) the generator may not have fuel to operate.

Last, a note on timing: When we say 'arrange fuel in advance' in this example, we mean however far in advance of the operating day as is necessary (a day, a week, a month, or a season). Though such timing issues matter in practice, in this simplified example, *how far* in advance is not material. Rather, the fact that there are up-front, irrevocable costs to arranging fuel in advance of the operating day raises two key questions. First, would a competitive generator choose to incur them? Second, would its decision produce the best outcome for the system as well? We consider each in turn, next.

► **Society's preferred outcome.** First, let's examine what would be the most cost-effective outcome for the system. Arranging fuel in advance has an up-front cost of $40, and 80% of the time those arrangements will not turn out to be used. That might suggest arranging fuel in advance is not worthwhile, from the standpoint of a cost-effective system.

But consider the benefits. Although high demand is unlikely, it occurs 20% of the time. When it does, arranging fuel in advance means incurring a marginal cost of $70/MWh and being able to avoid dispatching an expensive resource that costs $400/MWh. The expected value of the benefit to the system (*i.e.,* the expected cost saving) from avoiding that 'bad' scenario is:

$$20\% \times (\$400/\text{MWh} - \$70/\text{MWh}) = \$66/\text{MWh}.$$

On net, that means arranging fuel is indeed worthwhile: The cost of arranging fuel in advance of the operating day is $40 for the MWh, and the expected value of the benefit is $66/MWh, so the expected value of the net benefit is $66 – $40 = $26/MWh. When the decision to arrange fuel must be made in advance of the operating day, society would be better off (*i.e.,* there is positive expected cost saving, on net) if the generator invests the $40 – even though it may not be used.

Note that in coming to that conclusion, we have not introduced any reliability considerations. We simply have concluded that from the standpoint of minimizing the system's expected cost, it is efficient to incur the up-front cost of arranging fuel in advance even though it is most likely to *not* be needed.

In this sense, from the system's standpoint, arranging fuel in advance is like insurance. Arranging fuel involves an up-front, irrevocable cost (an insurance premium), and provides a benefit in a state of the world that is *not* highly likely to occur (like most insurance claims). And yet, if that 'bad' scenario occurs, it would be very valuable to have the insurance. Finally, like a well-chosen insurance policy, in this example the *expected* benefit exceeds the expected cost of arranging fuel in advance – making the insurance it provides a desirable 'investment' from the standpoint of the system overall.

► **The generator's decision.** From a commercial standpoint, it is prudent for the generator to incur the costs of arranging fuel in advance of the operating day only if its expected net revenue is greater as a result of doing so than if it does not. In this example, if the generator does not arrange fuel, its earnings are straightforward: it will not operate the next day and so will earn nothing. Let's now consider the alterative decision to arrange fuel, which, as illustrated below, entails an expected loss to the generator. As a result, the generator would not find it profitable to acquire the fuel, though society would be better off if it did.

The cost of the 'investment' in fuel arrangements prior to the operating day is $40 up front. As before, 80% of the time demand will be low and those arrangements will not to be used. The other 20% of the time, demand is high and the generator is dispatched. In that high-demand scenario, the generator is paid the real-time LMP of $120/MWh and incurs a marginal cost of $70/MWh, earning a gross margin of $120 – $70 = $50/MWh.

That $50/MWh gross margin is more than enough to cover – on a high-demand day – the up-front cost of arranging fuel. However, the generator does not expect to operate every day. After all, demand is high only 20% of the time. That risk changes the generator's profit and loss calculus entirely.

Accounting for that uncertainty, the generator's expected net revenue if it arranges fuel is a loss. The up-front $40 investment in fuel arrangements (a cost for sure) has only a 20% chance of earning a gross margin with which to cover it. The generator's expected profit, if it arranges fuel, is a net loss of $30, as shown in Table 2-2 below. In other words, arranging fuel in advance is not financially prudent for the generation owner.

Table 2-2. Generator's Expected Net Revenue for Example 1						
			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120.00	$ -	$ -	$ -
[3]	Total Settlement	[1]+[2]	$ 120.00	$ -	$ -	$ -
Generator's Costs						
[4]	Advance Fuel	*F*	$ (40.00)	$ (40.00)	$ -	$ -
[5]	Marginal Cost	*MC*	$ (70.00)	$ -	$ -	$ -
[6]	Total Cost	[4]+[5]	$ (110.00)	$ (40.00)	$ -	$ -
Generator's Net Revenue						
[7]	Scenario Net Revenue	[3]+[6]	$ 10.00	$ (40.00)	$ -	$ -
[8]	Scenario Likelihood	*p* or (1-*p*)	20%	80%	20%	80%
[9]	**Expected Net Revenue**	SumProd [7]*[8]	**($30)**		**$0**	

Since there are many numbers to track in these calculations, and because we will extend this example later, Table 2-2 provides the relevant settlements and net revenue calculations for this generator for four situations: high and low demand, each with and without arrangements for fuel in advance of the operating day. To explain the generator's bottom line, as shown in row [9]:

- The bottom right-hand cell shows that if the generator does not arrange fuel, its expected profit is zero (since it does not operate), regardless of whether demand is high or low.

- The bottom left-hand cell shows that if the generator does arrange fuel, it is indeed in the red – it incurs an expected loss of $30. This is because 20% of the time, the generator will realize net revenue of $10/MWh, for an expected gain of $2/MWh. And 80% of the time, it will realize a $40/MWh loss, for an expected loss of $32/MWh. Adding the positive $2/MWh and the negative $32/MWh yields a net expected loss of $30/MWh.

The point of Example 1 is important. The market, in its current form, may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system.

2.2.2 Reliability Risks and Problem 1

In the prior example, the generator's rational decision is not cost-effective for society. There is a true market failure to incent efficient outcomes, causing higher expected costs to society as a result. However, that is not the only potential problem.

Let's now modify the prior example slightly: Assume next that if the generator does not arrange fuel in advance of the operating day and demand is high, then the system will not have sufficient resources to avoid a shortage of reserves. In this 'bad' scenario, the real-time price for reserves (in shortage) would be $1,000/MWh and the LMP (we'll assume) would be higher, at, say $1,400/MWh. If the generator does arrange fuel, however, we'll assume the same outcomes as before with, no reserve shortage.

For simplicity, we will first analyze this scenario based on the energy market's incentives and outcomes. There is also an impact (in this new scenario) to consider from capacity market performance incentives. That involves additional calculations, which we will subsequently address further below.

From the generator's standpoint, nothing changes due to the now-higher LMP that may occur if it does *not* arrange fuel. It was never paid the LMP that prevails in the 'bad' scenario (since it does not operate when that occurs) – and therefore that high LMP scenario does not incent it to invest in fuel supply arrangements. In terms of the numbers in Table 2-2 above, the value of the real-time LMP in the cases with 'No Advance Fuel' (the right-hand columns) produces no revenue for the generator. And, if it does arrange fuel in advance of the operating day (the left-hand columns), and by so doing prevents the reserve shortage, it would still have an expected loss of $30/MWh.

Things are *not* the same from society's standpoint in this new situation, however. From that perspective, the benefit of arranging fuel in advance is now much larger. Here, we will assume that the costs to society of the reserve shortage are the sum of the marginal alternative generator's cost (again assumed to be $400/MWh) and the 'cost' at which the market values a reserve shortage (at the margin), which is presently $1,000/MWh.[20] That means arranging fuel in advance avoids incurring, if high demand occurs, a cost of $1,400/MWh, and instead using $70/MWh energy (at the margin) to meet demand. That 'good' scenario has an expected benefit (expected cost saving) to the system of:

$$20\% \times (\$1,400/\text{MWh} - \$70/\text{MWh}) = \$266/\text{MWh}.$$

On net, that means arranging fuel is indeed worthwhile for the system: The cost of arranging fuel in advance of the operating day is $40/MWh, and the expected value of the benefit of doing so is $266/MWh, for a *net* expected benefit of $266/MWh – $40/MWh = $226/MWh.

The point here is simple. If a generator's decision to arrange fuel in advance is material enough to impact – with *some* probability – whether or not the system experiences a reserve or energy shortage, then the divergence between society's and the generator's incentives *gets worse*. That is, the problem of the misaligned incentives does not have only adverse efficiency consequences. It can also have adverse reliability consequences. As this case shows, the competitive generator's rational decision is again not to arrange fuel, but society would be even better off – and the system's reliability risk lower – if it did. The more severe the consequences of the generator's decision, the more its incentives are misaligned from society's.

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[20] This $1,000/MWh value is an existing administrative real-time reserve shortage price, defined in the Tariff as a Reserve Constraint Penalty Factor, and associated with the system's real-time minimum total operating reserve requirement. *See* Tariff Section III.2.7A.

We should note again here that this case with the potential reserve shortage does not incorporate other market incentives that are important in New England. Since June 1, 2018, resources that supply energy face stronger marginal incentives to perform under the ISO's two-settlement capacity market design (Pay for Performance or PFP). We address how PFP affects these situations in greater detail, further extending this example, below.

2.3 Insights: Problem 1's Consequences and Implications

Although these examples are simple illustrations of a market design problem, they identify several key points that hold generally. As noted previously, investments in energy supply arrangements can be characterized as insurance, in the sense of paying more to achieve more reliable outcomes. That's logical enough, but isn't the whole story.

In these examples, investments in energy supply arrangements *lower* the system's expected total cost – paying *less* overall – to achieve equally (or more) reliable outcomes. That's a far more sweeping observation. It says the system would meet demand more cost-effectively overall if the generator made the up-front investment to arrange fuel, even though the arrangement may not be used. However, under the current market design, making such fuel supply arrangements may not be financially prudent from the generator's standpoint of maximizing its expected net revenue. And the generator is acting perfectly rationally and competitively (offering at its marginal cost) throughout.

What is the crucial insight here? Simply that the market price for energy – what consumers value consuming – is impacted by the supplier's investment in fuel arrangements (at least, with positive probability). Thus, in taking a costly action (incurring the up-front cost of arranging fuel), society benefits more than the generator does. The difference between those benefits (to the generator) and cost savings (to society) is the misaligned incentives problem, and it results in higher expected costs to society as a result.

Equally important, this misaligned incentives problem becomes worse precisely when the region's fuel security constraints are tightest. In such conditions, the social benefits of arranging energy supplies in advance can be large, because of the high production costs and prices society *avoids* by doing so (the $400/MWh in the first example). And we should be willing to spend more up-front to mitigate a risk when its likelihood is greater, or when its consequences (if it does occur) are more severe. Unfortunately, those higher-risk conditions are precisely when the misalignment problem is at its worst: since the generator does not internalize (that is, is not the beneficiary of) the high price that is avoided by its investment in fuel arrangements, the divergence between its private incentives and society's preferred outcome is greatest precisely society would benefit the most.

In sum, the misaligned incentives problem described here will not solve itself. In fact, as the tight fuel infrastructure constraints in New England show no signs of dissipating in the foreseeable future,[21] the underlying risk likelihood appears to be growing over time – and, if unaddressed, the consequences of the misaligned incentives problem will only get worse.

2.4 Why Doesn't Pay-for-Performance Solve This?

Resources in the New England power system are incented, in real-time, not only by the real-time LMP, but also by a performance incentive created by the ISO's Pay-for-Performance capacity market rules. The PFP market rules will impact a resource's incentives to arrange fuel in advance of the operating day whenever the conditions demarking a PFP event, known as a Capacity Scarcity Condition, may occur.

As an initial observation, note that in the first analysis of Example 1 in Section 2.2.1, there is no reserve deficiency, and the PFP market rules would not change any of the calculations in Table 2-2. Yet that example shows how the energy market may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. This market failure to produce efficient, socially beneficial investment decisions would not be altered by PFP in that case, as it stands wholly apart from the circumstances when PFP would apply.

In more extreme situations where there are potential shortages of energy or reserves (as in Section 2.2.2), the impact of PFP on these incentives is more nuanced. Generally, even when there may be a reserve shortage, PFP helps, but it does not fully solve, Problem 1. To illustrate why, we next extend the prior numerical examples.

2.4.1 Example 1 and Pay-for-Performance

We'll build on the extended version of Example 1 discussed in Section 2.2.2, where there is a potential reserve shortage, and now layer in the additional settlements associated with PFP.

► **Additional assumptions.** To capture the impact of PFP, assume the generator has a Capacity Supply Obligation of 1 MW (its same capacity as before). During the hour considered in this analysis, assume the system's Balancing Ratio (BR) is 80% (that exact value is not critical to what follows), and that the Performance Payment Rate (PPR) is equal to its current Tariff value of $3,500/MWh.[22]

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[21] *See* Brandien Testimony at pp. 23-26.

[22] Pay for Performance is a two-settlement capacity market design, with both a forward payment (set upon assuming a Capacity Supply Obligation) and a spot (or real-time) payment for deviations (calculated for each resource during a Capacity Scarcity Condition). Under PFP, the spot payment is known as the performance payment, and the Balancing Ratio and the Performance Payment Rate are both components of the performance payment calculation. The Performance Payment Rate is the design's Commission-approved, proxy real-time price – the rate at which deviations from forward obligations are settled. The Balancing Ratio scales a resource's forward obligation such that instead of being an obligation for a fixed quantity of capacity, it is an obligation to provide a specific share of the system's needs during the scarcity condition. Generally, if the scarcity condition occurs on a high-load day, the Balancing Ratio will be higher, and the participant's actual performance will be assessed relative to a higher percentage of its forward obligation; if the scarcity

We again assume that if the generator does not arrange fuel in advance of the operating day and demand is high, the system will not have sufficient resources to avoid a shortage of reserves. In that 'bad' scenario, as before, the LMP would be $1,400/MWh. If the generator does arrange fuel, however, then (in that 'good' scenario) we have the same outcomes as before with no reserve shortage. All other assumptions, including the generators' up-front and marginal costs of fuel, and the likelihood of high or low demand, are the same as those summarized in Table 2-1, above.

► **The generator's decision.** In this revised example, if the generator does arrange fuel in advance of the operating day, nothing changes from the outcomes summarized in the left-side columns of Table 2-2 previously. There is no reserve shortage: if demand is low the generator does not operate, and if demand is high it operates and earns a gross margin of $120 – $70 = $50/MWh. As before, the expected value of its gross margin is 20% × $50/MWh = $10/MWh, which is not enough to cover its $40 up-front cost. Thus, as shown in the bottom row of Table 2-2, if the generator arranges fuel in advance, it expects to incur a net loss of $30.

Let's now consider the alterative decision to not arrange fuel in advance of the operating day. In this case, the generator no longer has an expected profit of zero when it does not run. Instead, it will incur a non-performance charge in PFP settlements.

Table 2-3 below summarizes the relevant calculations. The general PFP settlement formula (in simple terms) is

Performance Payment = PPR × (A – BR) × CSO × *event duration*

where A is the resource's output (in MWh). In this example, A is zero if the generator does not make arrangements for fuel, its CSO is 1 MW, and the event duration is assumed to be one hour. Therefore, the performance payment would be a charge of:

$3,500/MWh × (0 – 80%) x 1 MW CSO × 1 hour = – $2,800.

This is shown in row [4] of Table 2-3, for the scenario (column) with high demand and no advance fuel.

Of course, whether or not that occurs depends if demand is high or not. As before, if demand is low, there is no reserve shortage, the generator is not called to operate, and its net revenue in the low-demand scenario is zero. However, there's a 20% chance of high demand and, without the fuel to operate, it would then incur the PFP non-performance charge of $2,800. The expected value of the generator's net revenue if it does not make arrangements for fuel in advance of the operating day is therefore

condition occurs on a low-load day, the Balancing Ratio will be lower, and the participant's actual performance will be assessed relative to a lower percentage of its forward obligation. For a more detailed explanation of the PFP rationale and mechanics, *see* Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market, FERC Docket Nos. ER14-1050-000, -001 (filed January 17, 2014).

(20% × (– $2,800)) + (80% × $0) = – $560.

See the bottom row of Table 2-3. Viewed this way, the profit maximizing decision – which, in this case, is a *loss minimizing* decision – is laid bare: Arranging fuel involves an expected net loss of $30, but not arranging fuel involves an expected net loss of $560. Given these stark alternatives, the generator's prudent course of action is to incur the up-front cost of arranging fuel.

Table 2-3. Generator's Expected Net Revenue for Example 1 with PFP

			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120	$ -	$ -	$ -
[3]	PFP Performance Pmt	*PPR * (A - BR)*	$ -	$ -	$ (2,800)	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 120	$ -	$ (2,800)	$ -
Generator's Costs						
[5]	Advance Fuel	*F*	$ (40)	$ (40)	$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -	$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)	$ -	$ -
Generator's Net Revenue						
[8]	Scenario Net Revenue	[4]+[7]	$ 10	$ (40)	$ (2,800)	$ -
[9]	Demand Probability	*p* or (1-*p*)	20%	80%	20%	80%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**($30)**		**($560)**	

In that sense, PFP helps to solve Problem 1, as suggested previously. As before, society is better off if the generator arranges fuel in advance of the operating day, as it helps to avoid the high costs and reliability risks of a reserve shortage. And the generator is incented to do so, because of the high financial price to be paid if it is unable to perform when a reserve shortage occurs.

2.4.2 So Why Doesn't PFP Fully Solve the Problem?

There is much more to the PFP question we started with. As noted at the outset, PFP helps, but does not fully solve, Problem 1. Let's now consider a minor change to the preceding scenarios that will reverse the foregoing result – and show how PFP does not fully solve the problem with (arguably) more "realistic" risk likelihoods.

The preceding PFP example had a number of simplifying assumptions to keep the calculations simple. One seemingly unrealistic assumption is that there would be a 20% chance of a reserve shortage (absent the fuel arrangements). Capacity Scarcity Conditions, in practice, are rare events. Let's now see what happens if we re-do the preceding calculations assuming that there is only a 1%

chance of a reserve shortage (absent the fuel arrangements). That lower risk level will change things significantly, and show that PFP does not fully solve Problem 1.

To expedite the narrative, Table 2-4, below, shows the full settlements and expected net revenue for the generator with PFP under the same assumptions as before, but now with only a 1% chance of high demand. The bottom row corresponding to 'with fuel arrangements' now produces an expected loss of $39.50, which is close to the $40 up-front cost of arranging fuel. That $40 is now a total loss 99% of the time, offset by a slim 1% chance that demand is high, the unit runs, and makes its $50 gross margin. The generator's net expected revenue, if it arranges for fuel in advance of the operating day, is thus (1% × $50/MWh) – $40 = – $39.50/MWh, a net loss.

Table 2-4. Generator Expected Net Revenue for Example 1 with PFP

			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120	$ -	$ -	$ -
[3]	PFP Performance Pmt	*PPR * (A - BR)*	$ -	$ -	$ (2,800)	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 120	$ -	$ (2,800)	$ -
Generator's Costs						
[5]	Advance Fuel	*F*	$ (40)	$ (40)	$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -	$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)	$ -	$ -
Generator's Net Revenue						
[8]	Scenario Net Revenue	[4]+[7]	$ 10	$ (40)	$ (2,800)	$ -
[9]	Demand Probability	*p* or (1-*p*)	1%	99%	1%	99%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**($39.50)**		**($28.00)**	

What if the generator does not arrange fuel in advance of the operating day? As before, if demand is high, there is a reserve shortage and the generator would incur the PFP performance charge of $2,800. However, that has only a 1% chance, so the expected value of the generator's PFP performance charge is now comparatively trivial: 1% × $2,800 = $28, as indicated on the right side of the bottom row of Table 2-4.

Comparing the two cases, the generator's prudent financial decision is again the loss-minimizing one. Arranging fuel involves an expected net loss of $39.50, but not arranging fuel – which now is very unlikely to be used – involves an expected net loss of $28. The generator is financially better off, given these alternatives, if it does *not* incur the up-front cost of arranging fuel. Yet, as before, society would be better off if it did: The system's outcomes would be more cost-effective, and the reliability risk of a reserve shortage would be reduced. The misalignment problem remains.

In that sense, PFP does not fully solve Problem 1. Even with PFP, society faces a lower reliability risk if the generator arranges fuel in advance of the operating day, but those arrangements may not be consistent with the generator's commercial interest (particularly if the likelihood of reserve shortages is small). The reason PFP does not fully solve Problem 1 is not complicated. As this example illustrates, when the risks of a reserve shortage are low, the incentive PFP creates for performance are significantly muted – too muted for it to be privately financially beneficial for the generator to incur the up-front costs of arranging fuel, the costs of which will be a total loss most of the time.[23]

2.5 Insights: The Misalignment Problem's Root Causes

Example 1 shows that even when up-front investments in resources' energy supply arrangements would be cost-effective from society's standpoint, the current market design may not provide sufficient financial incentives for competitive generation owners to undertake them.

Stated generally, Problem 1 has three root causes, all of which are at work in the mechanics of Example 1 (and variants thereof) discussed previously. These three root causes are:

Root Cause 1: **Uncertainty** over whether the generating unit will be in demand, or not.

Root Cause 2: **Irrevocable (*i.e.,* up-front) costs** of making arrangements for fuel, which must be incurred in advance of learning whether the generator will be in demand (asked to operate) or not.

Root Cause 3: **Materiality of energy supply arrangements,** in the precise sense that if the generator does make arrangements for fuel in advance, then with some probability (*i.e.*, when the generating unit is in demand), the real-time price for energy will be lower, or reliability will be better, than if it does not.

The first two of these root causes are conditions commonly affecting fuel supply arrangements for much of the generation fleet – such as the oil-fired resources and higher-cost (higher heat-rate) gas-fired resources that do not often clear in the day-ahead energy market. As a result, their owners face uncertainty over whether those resources will be called to operate in real-time (and, more broadly, uncertainty over how often they may run). These causes have existed relatively consistently for many years.

The third root cause merits emphasis. In simple terms, if the existence of advance fuel supply arrangements impacts whether real-time energy prices are lower, or whether reliability outcomes

[23] Of course, one might note – accurately – that if lack of fuel to operate was widespread in the generation fleet when those generators are 'in demand,' then the likelihood of reserve shortages may no longer be small. And indeed, as the earlier example (when there was a 20% risk of a reserve shortage) shows, if the likelihood of a reserve shortage is higher, then the impact of PFP will be far more powerful. It then becomes a better decision to arrange fuel proactively to ensure the generator can operate. So, in a sense, this problem is 'self-correcting' because PFP would tend to induce resources to arrange fuel to ensure they can perform *if* the frequency of reserve shortages becomes high enough. That, however, should be viewed as a Pyrrhic victory from reliability standpoint.

are improved, then those arrangements are material. And this materiality is one important cause of the misaligned incentives problem. While it may seem too obvious to state, if this were not the case – that is, if the presence of advance fuel arrangements had no effect on prices or reliability – then the region would not face an energy security problem in the first place.

To see why, consider that if – counterfactually – the presence of such arrangements was *not* material to prices or reliability, then in all cases there must be *another* resource available at the same time, and at the same offer price (or less), that could serve the same increment of demand. And in that case, there is neither a market efficiency problem nor a reliability problem: the system would always have another resource to meet incremental demand, at the same cost. In short, for the misaligned incentives problem (Problem 1) to arise, generators' energy supply arrangements must impact potential real-time outcomes in the precise sense that without them, there is a chance of a higher real-time price, a higher likelihood of a shortage (of reserves or of energy) – or both.

► **The evolution of the system in recent years has made the materiality of energy supply arrangements much more significant.** In the past, generators commonly had large, ready stockpiles with which to fuel a run whenever committed or dispatched. If some day-ahead scheduled resource wasn't able to operate unexpectedly (for any reason), there were always sufficient energy stocks to dispatch up another generator in its place. This was true provided the system was committed (or could be supplementally committed) to have sufficient capacity for the peak hour, a main day-ahead operating plan focus in the past.

Now, with constrained fuel infrastructures, retirements of generators with ample fuel storage, and evermore just-in-time generation from renewable technologies, it is no longer assured that if a day-ahead scheduled resource isn't able to operate unexpectedly (for any reason), there will always be sufficient energy to dispatch up another generator in its place – at a similar or small change in the real-time LMP. Instead, if a generator has no fuel to operate during cold weather conditions, then there is an increasing likelihood that the real-time LMP will be set by either (*a*) an expensive next resource 'in the stack', or (*b*) scarcity pricing that signals a deficiency in the system's supply of energy and reserves.

For these reasons, as New England's resource mix has evolved toward technologies with predominantly just-in-time energy sources, the materiality of energy supply arrangements has become a more significant potential concern than in the past. Moreover, we do not expect this issue to abate in the future, given the generation fleet's dramatic shift to more and more just-in-time resources.[24]

[24] *See* Brandien Testimony at pp. 23-26.

2.6 Problems 2 and 3: Operational Uncertainties and Insufficient Day-Ahead Scheduling

We now turn to Problems 2 and 3, concerning operational uncertainties and insufficient day-ahead scheduling. As noted throughout the foregoing sections, with the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, resources that do not expect to run the next day (*e.g.,* that do not receive an award in the day-ahead market) may not have sufficient incentives to make costly energy supply arrangements in advance.

This precipitates the concerns identified as Problem 2 and Problem 3. Problem 2, operational uncertainties, arises when there may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss, particularly during cold weather conditions. Problem 3, insufficient day-ahead scheduling, occurs when the day-ahead market's outcome produces next-day generation and (net) import energy schedules that are insufficient to cover the region's forecast energy demand next operating day. This commonly arises when market participants procure less energy in the day-ahead market than the ISO's forecast of their real-time demand for the next day.

This analysis builds on Problem 1 (misaligned incentives) and the insights from the prior section, but now adds the practical considerations of the power system's operational needs.

2.6.1 Three Essential Reliability Services

As explained in the Brandien Testimony, the ISO is increasingly concerned there could be insufficient energy available to the New England power system.[25] There are several distinct ways in which the system may face a 'gap' between the energy available and the energy required to ensure reliable daily system operations, as summarized next.

Currently, the ISO relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, for the essential reliability services necessary to fill such energy gaps. But the ISO does not currently procure or compensate for these types of service capabilities on a day-ahead timeframe. This, combined with the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, leaves the region vulnerable in a way that must be addressed.[26]

These energy gaps – and the resource capabilities that the ISO relies upon to fill them – fall into three broad operational categories.

A. **The energy gap between day-ahead market schedules and forecast energy demand.** This gap arises when the total energy cleared in the day-ahead market from physical supply resources (generation and net imports into New England) are less than the ISO's

[25] *See* Brandien Testimony at pp. 23-24.

[26] *See, generally,* Brandien Testimony at pp. 24-26.

forecast energy demand, in one or more hours, during the next (operating) day. This gap is Problem 3, insufficient day-ahead scheduling.

Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast energy demand each hour – not simply the level of demand cleared in the day-ahead energy market.[27] Therefore, the energy to cover this gap is supplied through the dispatch and post-market commitment of other resources operating above, or that did not receive, a day-ahead market award.[28]

Given the inefficiently low incentives for resources without day-ahead energy schedules to arrange fuel in advance of the operating day (as explained throughout this Section 2), with these Energy Security Improvements the ISO is creating a new energy imbalance reserve ancillary service in the day-ahead market. As discussed in detail below, this will strengthen the incentives for *all* of the resources needed to satisfy forecast energy demand – a requisite component of a reliable next-day operating plan – to arrange energy supplies in advance of the next operating day.

B. Operating reserves for fast-start and fast-ramping generation contingency response. This gap arises when there is a sudden, unanticipated supply loss during the operating day.[29] This gap is directly related to Problem 2 – operational uncertainties.

Energy to cover this gap comes from resources that the ISO relies upon for real-time operating reserves. These include both off-line (fast-start) generation and the unloaded 'upper blocks' of on-line generation (called 'spinning' reserves). The ISO relies upon these capabilities to ensure the system is prepared to promptly restore the system's energy balance (consistent with the timeframes established in applicable reliability standards).[30]

Because unanticipated supply losses are just that – unanticipated – the resources that the ISO relies upon for this purposes have no reason to expect to operate (or to operate at levels above their day-ahead schedules) the next day. Accordingly, for the reasons explained in Section 2.5, they too face inefficiently low incentives to arrange fuel in advance of the operating day. With these Energy Security Improvements, the ISO is creating a new day-ahead Generation Contingency Reserve service that will strengthen the incentives for such resources to ensure they have energy supplies in advance of each operating day.

C. Replacement energy. This gap occurs when a resource scheduled in the day-ahead energy market is unexpectedly unable to operate for an extended (multi-hour to multi-

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[27] *See* Brandien testimony at pp. 18-19.

[28] *See* Brandien Testimony at pp. 17-18.

[29] *See* Brandien Testimony at pp. 8-9.

[30] *See* Brandien Testimony at pp. 7-10.

day) duration. This is another manifestation of Problem 2 – operational uncertainty. In this situation, the ISO must again dispatch online resources above their day-ahead schedules, or supplementally-commit offline resources without day-ahead schedules, to supply sufficient energy to cover the energy gap through the balance of the day (and, if applicable, the day following).

As indicated in the Brandien Testimony, "In [New England's] increasingly energy-limited system, it is uncertain whether there will always be other resources capable of responding with sufficient energy to permit the power system to withstand a sudden, extended (multi-hour to multi-day) loss of a large generator or other supply source."[31] Given the analysis of Problem 1, that operational risk should come as no surprise: the current market design has no products to provide resources with the economically-appropriate incentives, or the compensation, to ensure they maintain sufficient energy supplies to serve the system's replacement energy needs for the balance of the operating day and beyond. Accordingly, in these Energy Security Improvements, the ISO is creating a new day-ahead Replacement Energy Reserve service that will strengthen the incentives for the resources the ISO relies upon for this purpose in its operating plans.

As summarized in the Brandien Testimony, these resource capabilities comprise three essential reliability services that the ISO relies upon in its operating plans to meet its reliability standards and criteria.[32] We will distinguish among them in this paper because they require different resource capabilities in order to cost-effectively address potential energy gaps that arise on, and persist for, different timeframes.

► **Implications.** Our present point is that the ISO relies upon much of the generation fleet's capabilities – above and beyond their day-ahead market awards – to satisfy the next-day operating plan's requirements and to maintain a reliable power system. For the reasons explained in detail in the Brandien Testimony, filling these energy gaps can no longer be an incidental aspect of the ISO's markets; these are indeed essential reliability services.[33] Resources, however, are not currently compensated in the day-ahead market for these capabilities. Indeed, since its inception, ISO New England has had no day-ahead ancillary services markets at all.

Instead, presently the ISO employs (unpriced) constraints in its day-ahead market unit commitment process to help ensure that there will be sufficient capability to cover the next-day forecast energy demand (category A) and sufficient operating reserves each hour of the next day (category B); and it employs out-of-market procedures and reliability-commitment tools (after the day-ahead market) to evaluate and ensure there will be sufficient resources to cover all three of these essential reliability services (categories A and C, respectively).

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[31] Brandien Testimony at p. 26.

[32] *See* Brandien Testimony at pp. 17-18, 26-28.

[33] *See* Brandien Testimony at pp. 17-18.

These out-of-market practices are increasingly problematic. Given the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, the ISO is increasingly concerned that the resources the system relies upon for these essential reliability services may not have energy supply arrangements that will enable them to operate on days when they have no reason to expect to run (or to run above or longer than their day-ahead market award, if any). In that event, if the system experiences an unexpected, extended large generation or supply loss during cold weather conditions – particularly, if it occurs when renewable resources' production capability is low (when the sun is down or the winds are calm) – the region may not have the energy needed to reliably fill the ensuing energy gap.[34]

2.6.2 Many Resource Types Can Potentially Provide These Essential Reliability Services

Importantly, the most cost-effective set of resources to fill the energy gaps described in categories A, B, and C can (and does) vary daily. It depends on the day-ahead cleared generation pattern, the cleared and forecast demand profile over the course of the day, available resources' lead-times and capabilities, weather and intermittent-resource energy production (actual and forecast), constraints on natural-gas pipelines supplying electric generation, and so on.

As examples, the types of existing resources the system may rely upon to provide these three essential reliability services include:

a) off-line fast-start dispatchable generators (generally, hydro-electric and distillate-fueled combustion turbines and internal-combustion units), which infrequently receive day-ahead energy market awards and are dispatched during the operating day as circumstances require;

b) higher-cost 'blocks' of combined-cycle generators that receive day-ahead awards below their maximum output (or possibly for a lower-output configuration), which the ISO may dispatch higher or schedule longer than their present day-ahead market energy schedules for the operating day;

c) higher heat-rate, combined-cycle generators that did not clear in the day-ahead market and may be committed (after the day-ahead market or, if necessary, intra-day) to satisfy the load forecast or for replacement energy; and

d) long lead-time oil-steam units, in certain situations (*e.g.* cold weather conditions) when these resources can be lower-cost than gas-fired alternatives or when gas pipeline constraints preclude gas-fired resources from serving the system's load-balancing and replacement energy needs.

► **Implications.** There is not a static set of resources, or a specific set of technologies, that is most cost-effective in meeting the system's operational needs for the three essential reliability services summarized above. It varies from day to day. Moreover, which specific resources the ISO may rely

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[34] *See, generally*, Brandien Testimony at pp. 23-26.

upon for these purposes as part of a reliable next-day operating plan depends on the generation commitments and energy schedules awarded in the day-ahead energy market.

Looking forward, the ongoing evolution in New England's resource mix will also change the set of resources the system potentially relies upon for these same operational purposes. Many of the resources in category (d) (long lead-time oil-steam units) the ISO considers at risk for retirement, which may subsequently leave the combined-cycle generators in categories (b) and (c) as the predominant resource types to satisfy the system's load-balance and replacement energy needs. Moreover, with time, new technologies may change this mix further. For example, as new storage-based technologies become more prevalent, and their economics and energy sustainability improves, the resources that prove most cost-effective to satisfy these same operational purposes may shift to make use of those technologies.

The broader point here is that in considering how to ensure sufficient revenue so that the resources that satisfy these operational purposes each day invest in reliable energy supply arrangements (to operate above their day-ahead awards), there isn't a specific resource 'type' or technology at issue. Rather, it is important that compensation be sufficiently dynamic to reward the resources that are the most cost-effective on any given day.

2.6.3 Magnitude of These Energy Gaps

The New England system has over 30 gigawatts (GW) of capacity resources that supply power, experiences a net summer peak demand of approximately 25-26 GW, and net power demand of approximately 21-22 GW or so during cold weather conditions. For context, it is useful to clarify how much of that supply capability the ISO typically relies upon for the three operational purposes described above.

The short answer is that the total quantity of power and energy the ISO relies upon to satisfy these three operational purposes varies from day to day. In recent years, day-ahead cleared energy demand, after subtracting net virtuals (*i.e.*, cleared virtual supply less virtual demand), is often within a few percent of the load forecast in most hours. However, that gap can amount to many hundreds of MWh (per hour) and occasionally over a GWh.[35] When the load-balance gap is large, the ISO relies on resources' capabilities above their day-ahead awards to cover the load forecast (category A above), and may supplementally commit (after the day-ahead market) additional generation for this purpose.

Operating reserves (category B above), currently has formulaic requirements applied in the real-time energy market. Total operating reserves for prompt supply-loss contingency response are typically in the range of 2.2 to 2.6 GWh per hour, and are based on the projected size of the largest

[35] *See* Section 6.1.2.

and next-largest source-loss contingencies each day. The specific amount required (for the peak hour of the operating day) is reported daily in the ISO's *Morning Report.*[36]

Replacement energy (category C above) is more complex, as it depends on the scheduled energy profile of the system's largest contingencies over the course of the day. This can vary from hour to hour if the largest contingency is, for example, an external interface with an hourly-varying import energy schedule for the next day; or it may be constant over the course of the day if the largest contingency is a fully-loaded resource with constant scheduled power output over time (such as a nuclear unit). As explained in greater detail in Section 7.3 below, the replacement energy needed for timely contingency reserve restoration in the New England system is commonly approximately 1.3 GWh.

The summary point here is that, on some days, the total capability that the ISO relies upon to satisfy the foregoing three operational purposes can be substantial – commonly 4 GWh (per hour) or more of generation capability. The total quantities required to provide a reliable next-day operating plan vary from day-to-day, and these quantities are objectively based on the forecast demand profile and the system's largest potential single-source energy losses during the course of the operating day. These are capabilities that are not remunerated in the day-ahead market today, however, as they are provided by resources' capabilities above and beyond the level of their day-ahead energy market awards.

2.7 Implications for Energy Security

The preceding discussion of energy gaps as they arise today highlights the essential reliability services that are most needed to address the three problems (Problems 1, 2, and 3) examined previously in Section 2. As illustrated in Example 1 above, and in Example 2 below, generating resources that do not expect to run the next day (*e.g.,* that do not receive, and do not expect to receive, an energy schedule in the day-ahead market) may not find it financially prudent to make costly energy supply arrangements in advance – as they may often not be used, resulting in a financial loss.

In contrast, consider resources that face much less uncertainty over their energy production. Since the implementation of the Energy Market Offer Flexibility market design improvements,[37] the ISO has not observed significant problems with gas-fired resources that clear in the day-ahead market failing to have sufficient fuel to meet their day-ahead energy market schedules. In the winter, the gas-fired resources that clear in the day-ahead energy market tend to be among the system's more

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[36] The Morning Report is available at https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report.

[37] *See ISO New England Inc., et al.,* Energy Market Offer Flexibility Changes, Docket No. ER13-1877-000 (July 1, 2013) (incorporating in the Tariff energy market offer-flexibility enhancements to allow market participants to modify their offers to supply electricity on an hourly basis within the operating day to better reflect changing fuel costs and opportunity costs in offers). *See also ISO New England Inc., et al.,* 147 FERC ¶ 61.073 (2014) (accepting, subject to conditions, the energy market offer-flexibility enhancements).

efficient (lower heat-rate) resources. As a general rule, more efficient resources face less uncertainty over whether (and for how many hours) they will clear each day. Moreover, generating units that have a superior heat rate (lower marginal cost of production) will be willing to spend the most each day to acquire whatever natural gas is available for electricity generation in New England.[38]

At the opposite end of the spectrum, the situation can be quite different for the resources that the ISO relies upon to manage uncertainty – that is, for the essential reliability services discussed in Section 2.6.1. These resources that provide these services are most likely to face inefficiently low market incentives to invest in the energy supply arrangements necessary to provide these capabilities reliably – even when such arrangements would be a cost-effective means to reduce reliability risks. That is the central energy security challenge facing New England's electricity markets.

It is instructive to examine further why we focus on these essential reliability services, and the fuel supply incentives for resources needed to achieve them. First, as noted earlier, resources do not receive a day-ahead market award, nor any day-ahead revenue, for the capabilities that the ISO relies upon to meet forecast-load imbalances, operating reserves, and replacement energy requirements. Moreover, the frequency with which the ISO will call upon any specific resource to provide these capabilities is inherently difficult for those resource owners to predict – as, by their very nature, these capabilities are used to manage uncertainties. Thus, these resources face considerable production uncertainty (the first of the three root causes of the misaligned incentives problem, discussed in Section 2.5 above) over whether and how often they will be called to operate, both day-to-day and over the season as a whole.

Second, there are up-front costs to proactively arrange the energy supplies (the second of the root causes discussed above) that will ensure a resource can operate if called unexpectedly during, or just prior to, the operating day. Examples include arrangements by natural gas-fired generators to procure and maintain LNG inventories at existing LNG facilities in the Northeast (for use when the interstate gas pipelines from the west are constrained), and making advance arrangements to enable fuel oil supplies to be promptly replenished at the region's dual-fuel (oil and gas), distillate, and heavy-oil power plants. These types of arrangements entail up-front costs to acquire fuel (or contractual rights thereto) that can then be used by the generator 'on demand.' Yet, for the reasons shown in Sections 2.2 through 2.5, in today's market construct it is generally unprofitable to incur the costs of arranging energy supplies that a resource does not expect to use.

Third, the beneficial impact to the system from those types of energy supply arrangements (or materiality, the third of the root causes discussed above) is likely to be particularly pronounced for the resources that the ISO relies upon for forecast-load imbalances, operating reserves, and replacement energy requirements. The reason is that the system tends to rely upon those

[38] Moreover, owners of efficient gas-fired generators that face relatively little uncertainty over their daily production during the winter commonly follow business strategies that hedge (financially) much or most of their generators' output in advance of the winter, which makes the owner relatively insensitive to (that is, not adversely impacted by) an unexpectedly high spot price of natural-gas when scheduling fuel for their resources each day.

capabilities the most when it experiences adverse conditions: when gas pipelines are highly constrained, when renewable resources experience adverse weather, or for any other reason that lead system conditions to change markedly from those anticipated day-ahead. During such conditions, whether or not a generator providing these capabilities has the energy to operate may have a more significant impact on market prices – and in extreme conditions, impact a potential reserve or energy shortage – than during normal operating conditions. That is, the resources providing these operational capabilities are most likely to be called upon during periods when their energy supply arrangements (or absence thereof) matter to market outcomes and to system reliability.

The bottom line is that the resources that the system relies upon for the three essential reliability services discussed in Section 2.6.1 are those we expect to be most adversely affected by the misaligned incentives problem (Problem 1). However, while it may be a cost-effective means to reduce reliability risks for these resources to invest in additional energy supply arrangements, the current market construct provides inefficiently low incentives to do so. As a result, the ISO is increasingly concerned that the system is relying upon resources for forecast-load imbalances, operating reserves, and replacement energy capabilities that have no day-ahead obligations – and, as a result, may not have sufficient energy supply to operate if called.

These observations imply it would be beneficial to improve today's day-ahead energy market construct so that the future resource mix will invest in energy supply (*e.g.*, fuel) arrangements that ensure these essential capabilities remain reliable and available to the power system each operating day.

2.8 Example 2: Multiple Generators with Energy and Reserves

In this section, we provide a more detailed example with both energy and reserves. The point is to show that the misaligned incentives problem, and its three root causes, are of paramount concern for the resources and capabilities that the system relies upon to manage uncertainties the next operating day. Moreover, this example highlights how the wholesale market, in its current form, may not provide sufficient incentives for the owners of such resources to invest in costly energy supply arrangements *even when* such investments would be a cost-effective means to reduce reliability risk.

Though we develop this next example in the context of energy and operating reserves, the same conclusions would hold similarly if we instead focused on the system's needs for forecast-load imbalances or replacement energy reserves. The situation with operating reserves is more intricate, however, because of how real-time operating reserves are co-optimized with energy during the operating day – and because a failure of these resources to arrange for sufficient energy to operate could create (or magnify) a real-time reserve shortage.

In this example, there are four generators that can provide both energy and operating reserves. To capture many of the factors identified in the prior section, real-time demand is uncertain, and the higher-cost generators do not receive day-ahead market awards. We consider a situation in which one of these higher-cost generators faces the possibility that real-time demand may be high enough for it to operate the next day, but it is more likely the generator will not be needed. Facing this uncertainty, it must decide whether or not to incur the cost of arranging fuel in advance of the operating day.

As with the earlier examples, the interpretation of 'arranging fuel in advance of the operating day' is flexible. It should be viewed as however far in advance as is necessary for the generator in question (a day, a week, a month, a season). In other words, *how far* in advance does not impact the conclusions, or the calculations, of this Example 2.

► **Assumptions.** The capacity and offer price parameters of the four generators are shown in the first panel of Table 2-5. We assume there is a single operating reserve product procured in the real-time market, and each generator's maximum capability to provide that reserve product (due to its ramp rate) is also shown in the table.

Table 2-5. Assumptions for Example 2			
Generator	**Capacity (MW)**	**Offer Price ($/MWh)**	**Reserve Capability (MW)**
Gen 1	100	$25	10
Gen 2	100	$30	20
Gen 3	50	$40	30
Gen 4	50	$90	40
Additional Cost Assumptions for Generator 3			
		Marginal Cost	**Up-Front Cost**
With Advance Fuel Arrangements		$40	$150
No Advance Fuel Arrangements		N/A	N/A
Real-Time Demand Scenarios			
	Low Demand	**Medium Demand**	**High Demand**
Energy Demand (MWh)	170	190	210
Scenario Probability	33%	33%	33%

In the second panel of Table 2-5, we show additional cost assumptions for Generator 3. Its costs depend upon whether or not it arranges fuel in advance of the operating day. If Generator 3 arranges fuel in advance of the operating day, then it must incur an up-front cost of $150. By 'up-front cost,' we mean that if the generator decides to arrange fuel in advance, it would incur the $150 cost regardless of whether or not it operates the next day. And then, in addition, it would incur a marginal cost of $40/MWh to operate – but that marginal cost is incurred only if it does indeed operate.

The additional, market-level assumptions are:

- Day-ahead energy demand is 190 MWh for the hour.

- Real-time energy demand is uncertain: it can be low (170 MWh), medium (190 MWh), or high (210 MWh), each equally likely, as shown in the bottom panel of Table 2-5.

- The real-time reserve requirement is 30 MWh/h.

Last, some simplifications: the time period considered is a single delivery hour; there are no transmission constraints; the generators have no commitment variables (*e.g.,* no startup costs or lead-times); and demand in the day-ahead market matches the ISO's load forecast, so there is no load-balance gap. These simplifications are intended to help focus on the essentials of energy supply incentives, and do not alter the insights of this numerical example.

2.8.1 Market Awards and Clearing Prices

We first evaluate the day-ahead and real-time market outcomes in two cases: Case A, where Generator 3 decides to make advance arrangements for energy supply in advance of the operating day; and Case B, where Generator 3 does not.

We will then examine which decision maximizes Generator 3's expected net revenue, as well as which decision would produce a superior net expected benefit to the system (*i.e.,* minimize the expected value of the system's total production cost).

The **day-ahead** energy market outcome is the same in Case A and in Case B, and is shown in Figure 2-1. The clearing price for energy is $30/MWh, set by Generator 2's offer price. The two lower-cost generators (Generators 1 and 2) receive day-ahead energy market awards, and neither of the two higher-cost generators (Generator 3 and 4) receives a day-ahead energy market award.

Note that there are no day-ahead market awards for reserves in this example, which mirrors the current day-ahead market design in New England. However, the ISO can observe from the day-ahead clearing outcomes that if there are no changes in system conditions, the system would have 80 MWh of operating reserves in real-time spread across three resources (Generators 2, 3 and 4), as shown in the bars shaded green in Figure 2-1.

Next we will turn to **real-time** energy market outcomes.

Case A: Generator 3 arranges fuel. In real-time, demand can take one of three levels. Figures 2-2, 2-3, and 2-4 show the real-time market's energy and reserve co-optimization results for the example's low, medium, and high real-time demand levels, respectively.

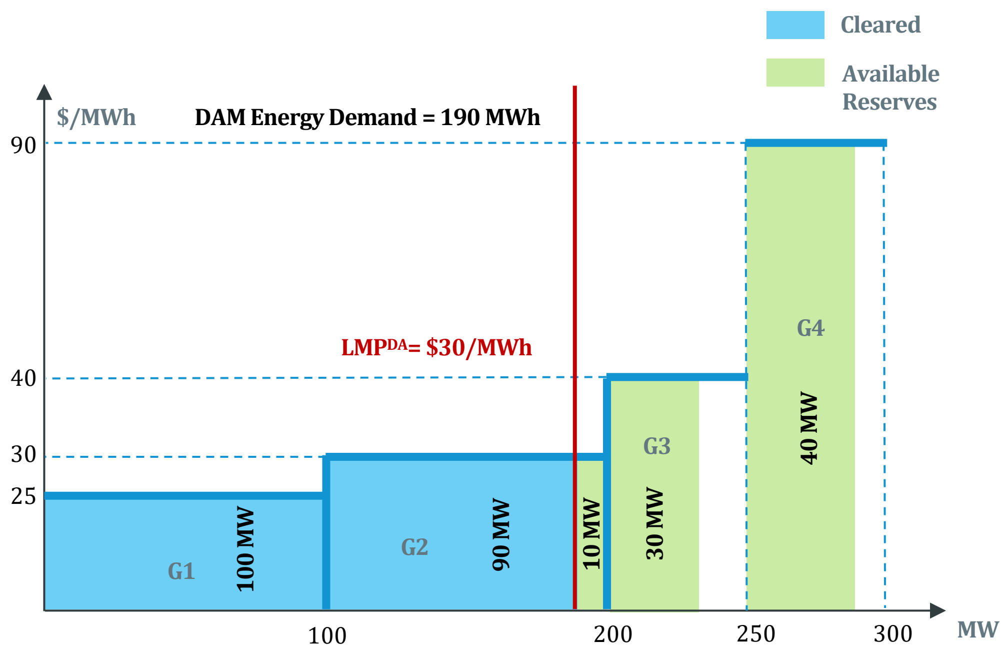

Figure 2-1. Day-ahead market outcomes for Example 2

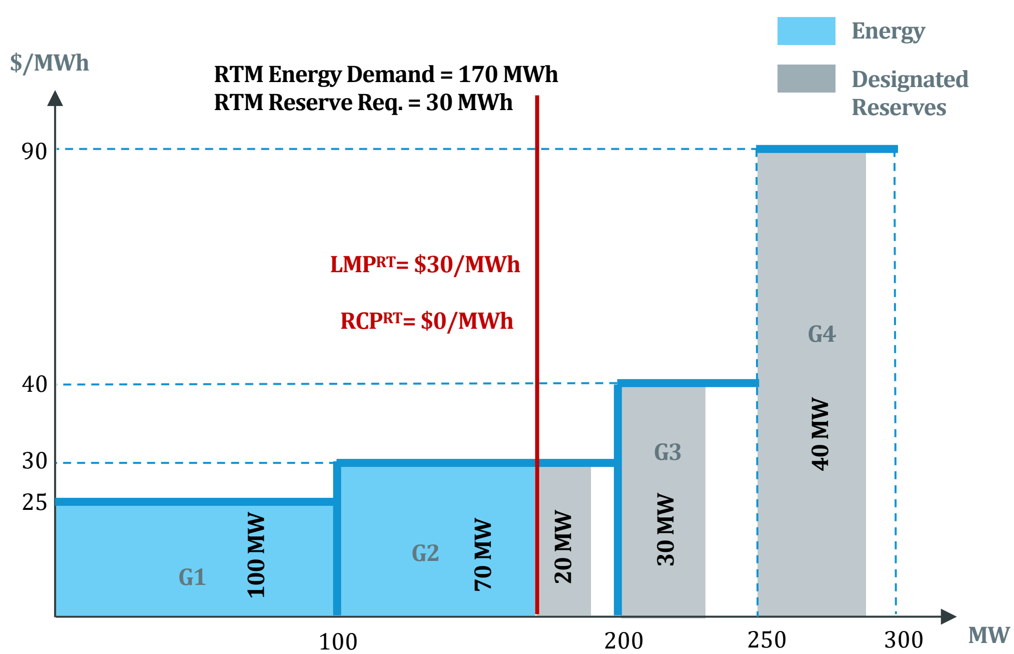

Figure 2-2. Low demand scenario real-time market outcomes for Example 2, Case A

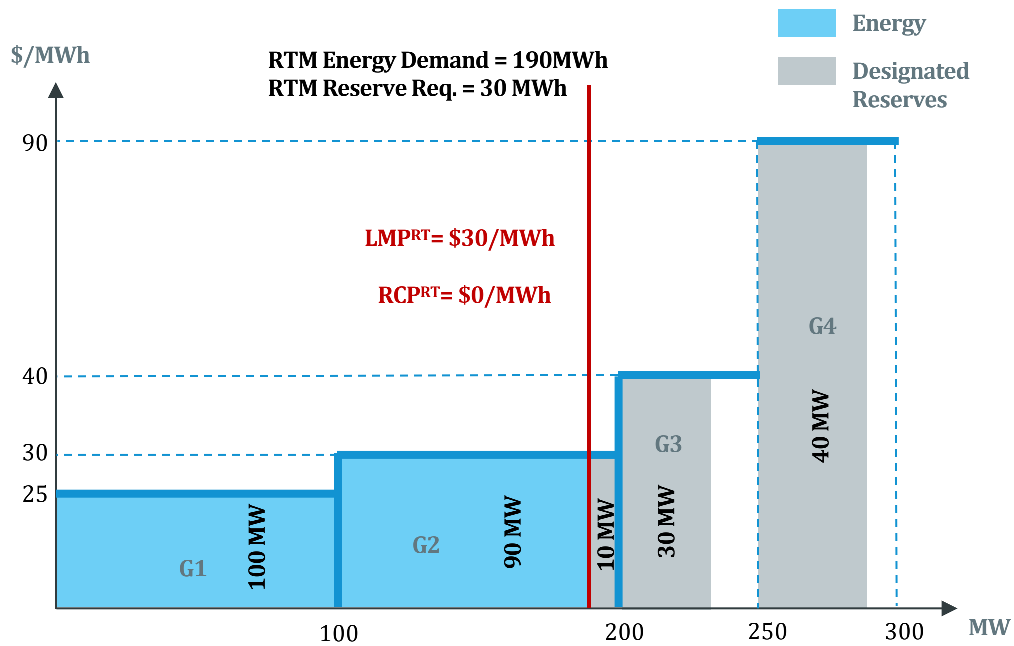

Figure 2-3. Medium demand scenario real-time market outcomes for Example 2, Case A

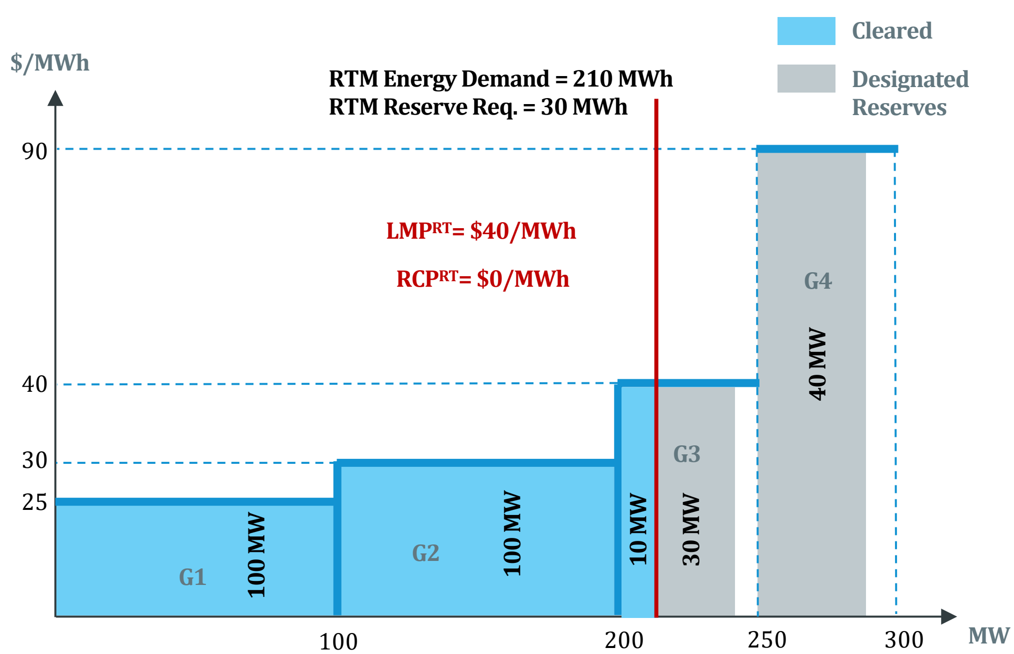

Figure 2-4. High demand scenario real-time market outcomes for Example 2, Case A

These results are summarized in Table 2-6. Figures 2-2 and 2-3, and Row [6] in Table 2-6, show that in the low and medium demand scenarios, Generator 2 remains marginal for energy and the real-time LMP is the same as day-ahead, at $30/MWh. In the high-demand scenario in Figure 2-4, Generator 3 is marginal for energy and sets the real-time LMP at $40/MWh. Row [5] in Table 2-6 indicates that in all three demand scenarios, the total supply of real-time operating reserves exceeds the reserve requirement of 30 MWh, so the real-time price for reserves is zero (as shown in row [6]).

Table 2-6. Market Outcomes for Example 2 , Case A: Generator 3 With Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	10	30
[4]	Gen 4	0	-	0	40	0	40	0	40
[5]	**Totals**	190	-	170	90	190	80	210	70
[6]	**Clearing Price**	$30	-	$30	$0	$30	$0	$40	$0
[7]	Scenario Total Production Cost			$4,600		$5,200		$5,900	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$5,233**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$5,700		$6,500	
[11]	**Expected Total Market Payments**					**$5,767**			

For purposes of evaluating cost-effective outcomes, the system's total production costs is shown in rows [7] and [9] of Table 2-6. Row [7] summarizes the system's total production cost in each demand scenario, under the maintained assumption that each resource offers competitively at its marginal cost.[39] Total production costs increase with real-time demand, naturally. Importantly, in these calculations we *exclude* the $150 up-front cost of Generator 3 to arrange fuel in advance of the operating day. We will bring that into the calculations in a subsequent step below.

Row [9] takes the probability-weighted average of the three scenarios' total production costs, which shows that the expected (value of the) system's total production cost is $5,233 (rounding to the nearest dollar). We will compare that outcome to the expected total production cost that prevails if Generator 3 does *not* have advance fuel arrangements in Case B below, which will identify whether

[39] The values in row [7] of Table 2-6 are calculated separately for each demand scenario by multiplying each generator's energy offer price (from Table 2-5) by its real-time market energy outcome (in MWh), and totaling the result. For example, in the high-demand scenario, the calculation is: $25/MWh × 100 MWh for Gen 1, plus $30/MWh x 100 MWh for Gen 2, plus $40 × 10 MW for Gen 3, which totals to a scenario total production cost of $5,900.

the $150 up-front cost of advance fuel arrangements would be cost-effective from the system's standpoint.

Of additional interest are total market settlements. Row [10] provides the total market settlements (including both the day-ahead market, and the deviation-based real-time settlements) for all resources in each demand scenario.[40] Row [11] takes their probability-weighted average to obtain the expected (value of the) total market settlements of $5,767 (again rounding to the nearest dollar). In this example, the expected total market settlements are both the expected total market revenue to the generators, and the expected total payments by buyers. The expected total market settlements are greater than the expected total production costs, both here and generally, because the low-cost generators earn infra-marginal rents – the usual economic reward for superior cost efficiency in a competitive marketplace.

Since there are many numbers involved in a multi-unit market with multiple products (*i.e.,* energy and reserves), we note here the key numbers to keep in mind from Case A:

- The high-demand scenario real-time LMP is **$40/MWh**, and real-time reserve price is **$0/MWh**.
- The expected system total production cost is **$5,233** for the hour, *excluding* Generator 3's $150 up-front cost of arranging fuel (which it will incur in this Case A); and
- The expected total market settlement is **$5,767** for the hour.

Case B: Generator 3 does not arrange fuel. Now consider the market outcomes if Generator 3 does not make arrangements for fuel in advance of the operating day. We will assume the ISO treats each generator as available unless informed otherwise by the generator, consistent with current ISO operational practice. If Generator 3 does not arrange fuel in advance, then we assume that it would seek to acquire fuel on short notice if instructed to operate the next day. In that situation, we assume that Generator 3 is physically unable to obtain fuel (and indicates to the ISO it not available), and the ISO would dispatch the system at least-cost without Generator 3.

In Case B, the real-time market outcomes are unchanged from before in the low and medium demand scenarios; Generator 3 is not instructed to provide energy in real-time in those scenarios. The outcome is different from before in the high-demand scenario, however. In the high-demand scenario in Case B, Generator 3 would not be able to obtain fuel to operate on short notice (by assumption) and would not be available. Therefore, the real-time dispatch would turn to the next higher-cost resource in the supply stack, Generator 4. Figure 2-5 shows the real-time market outcomes in Case B's high-demand scenario.

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[40] The values in row [10] of Table 2-6 are calculated by adding the total day-ahead market awards (190 MW multiplied by the $30 clearing price, or $5,700) to the product of the real-time deviation and the real-time clearing price in each of the three demand scenarios. For example, in the high-demand scenario, positive real-time deviations of 20 MW (10 MW each for Generators 2 and 3) are multiplied by the real-time clearing price of $40, for a total of $800. This amount is added to the $5,700 day-ahead settlement, for a total scenario market payment of $6,500.

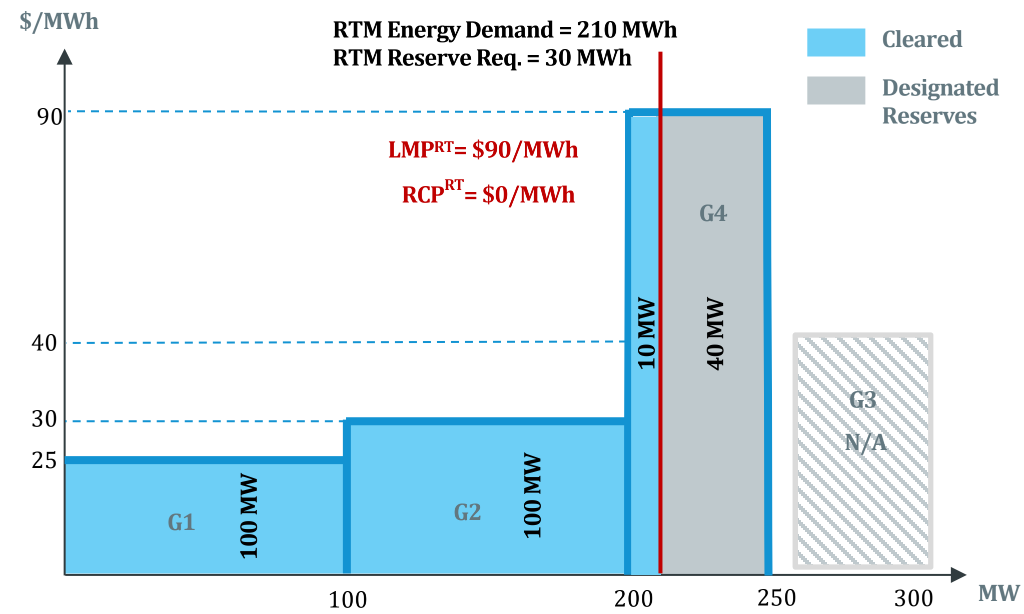

Figure 2-5. High demand scenario real-time market outcomes for Example 2, Case **B**

Table 2-7. Market Outcomes for Example 2 , Case B: Generator 3 Without Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	0	0
[4]	Gen 4	0	-	0	40	0	40	10	40
[5]	**Totals**	190	-	170	90	190	80	210	40
[6]	**Clearing Price**	$30	-	$30	$0	$30	$0	$90	$0
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,400	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cos**					**$5,400**			
[10]	DAM)			$5,100		$5,700		$7,500	
[11]	**Expected Total Market Payments**					**$6,100**			

Table 2-7 summarizes the market outcomes in Case B. To facilitate comparisons, we have shaded cells in light orange to highlight the (only) outcomes that differ from the outcomes in Table 2-6 for Case A, in which Generator 3 did arrange fuel in advance.

In the day-ahead market and in the low and medium real-time demand scenarios, Generator 2 remains marginal for energy, and the real-time LMP is the same as day-ahead, at $30/MWh, as shown in row [6]. In the high-demand scenario, Generator 4 now is marginal for energy and sets the real-time LMP at $90/MWh.

Even with Generator 3's unavailability in the high-demand scenario, however, row [5] indicates that the total supply of real-time operating reserves exceeds the reserve requirement of 30 MWh, so the real-time price for reserves is zero. Thus, in this example, Generator 3's unavailability impacts the real-time LMP significantly in the high-demand scenario, but its unavailability does not impact the price of reserves.

Last, for comparison purposes, we have re-calculated in Table 2-7 the system's total production costs and the total market settlements for each demand scenario in Case B, where Generator 3 does not have arrangements for fuel in advance of the operating day. Row [9] shows the expected (value of the) system's total production costs are $5,400. Row [11] shows the expected (value of the) total market settlements is now $6,100.

The key numbers to keep in mind from Case B are:

- The high-demand scenario real-time LMP is **$90/MWh**, and the real-time reserve price is still **$0/MWh**.
- The expected system total production cost is **$5,400** for the hour, when Generator 3 does not incur the $150 up-front cost of arranging fuel (in this Case B); and
- The expected total market settlement is **$6,100** for the hour.

2.8.2 Misaligned Incentives to Arrange Fuel

We now compare the outcomes when Generator 3 has the fuel to operate, versus when it does not. We will see that the energy and reserves markets currently provide inefficiently low incentives for Generator 3 to arrange fuel in advance, even though doing so would be beneficial and cost-effective from the system's standpoint.

► **Cost-effective outcome.** From the standpoint of operating a power system at minimum cost – in terms of the costs incurred by the suppliers to meet demand – the preferred outcome is if Generator 3 arranges fuel in advance. Even though that costs $150 up front and may not be used, it is a cost-effective investment. The system's expected total production cost without it is $5,400 (Case B) and with it is $5,233 (Case A), a difference of $167 – more than enough to cover the $150 up-front cost of the fuel arrangements. Thus, the most efficient, cost-effective outcome for the system is if Generator 3 arranges fuel in advance of the operating day.

This same conclusion applies from the perspective of buyers' total payments, which fall from $6,100 (in Case B) to $5,767 (in Case A, with the advance fuel arrangement). Although changes in buyers' total payments (also called *consumer surplus)* are not a measure of market efficiency, nor a measure of the minimum (most cost-effective) use of society's resources to meet demand, the reduction in total payments is logical: it avoids the scenario where high-cost Generator 4 must be used to meet demand, instead of the lower-cost Generator 3.

Before concluding that all is well, however, we need to bring a bit of the dismal science to bear on the situation. The flip-side of consumers' payments being lower in Case A (when Generator 3 has arranged for fuel) is that total market revenue to the generators is also lower in that case. The question then arises, specifically, whether – given the way the day-ahead and real-time markets currently operate – Generator 3 would find it profitable to invest in arranging fuel in advance of the operating day.

► **The generator's decision.** We now compare Generator 3's expected net revenue in each case, and whether its incentive to arrange fuel in advance is consistent with the efficient, most cost-effective outcome for the system.

The full settlement outcomes for Generator 3 in each case are detailed in Table 2-8. In brief, if Generator 3 does not arrange fuel, it produces zero energy in real-time (in any demand scenario) and its expected net revenue is $0, as shown in the bottom right row of Table 2-8. If it does arrange fuel, Generator 3 produces energy only in the high-demand scenario. In that scenario, it is the marginal unit, so it makes no profit in the real-time market (it sets the real-time LMP at its marginal cost). However, it incurs the $150 up-front cost to acquire fuel. Thus, Generator 3's expected net revenue if it arranges fuel in advance of the operating day is a net financial loss, of $150.

Table 2-8. Generator 3's Expected Net Revenue in Example 2

			Case A: With Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Real-Time Energy Deviation	*RT LMP*(Qe_RT - Qe_DA)*	$ -	$ -	$ 400	$ -	$ -	$ -
[3]	Real Time Reserves	*RT RCP * Qr_RT*	$ -	$ -	$ -	$ -	$ -	$ -
[4]	**Total Settlement**	[1]+[2]+[3]	$ -	$ -	$ 400	$ -	$ -	$ -
Generator's Costs								
[5]	Advance Fuel	*F*	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[6]	Variable Cost	*MC*	$ -	$ -	$ (400)	$ -	$ -	N/A
[7]	**Total Cost**	[5]+[6]	$ (150)	$ (150)	$ (550)	$ -	$ -	$ -
Generator's Expected Profit								
[8]	Scenario Net Revenue	[4]+[7]	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[9]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[10]	**Expected Net Revenue**	SumProd [8]*[9]		**($150)**			**$0**	

► **Implications.** The bottom line here is an important one. The energy market, in its current form, may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. In this example, all of the generators are acting perfectly competitively (offering at their marginal cost) throughout. Thus, the right conclusion to draw from Example 2 is *not* that there is a problem with the generators' behavior or their business acumen; rather, the right conclusion to draw from Example 2 is that there is a problem with the current energy market design.

2.8.3 Example 2-R: Reliability Risks

In Example 2, we have not (yet) introduced any reliability considerations. We simply have concluded that from the standpoint of minimizing the system's expected cost, it may be efficient to arrange fuel in advance even when it may not be needed. However, that is not the only potential problem.

We now consider an extension, Example 2-R, where Generator 3's decision to arrange fuel may impact whether or not there is a reserve shortage in real-time. We make the same assumptions as in in Example 2 before, but now 'scale up' two prior assumptions:

- *higher real-time reserve requirement* – the reserve requirement will now be 80 MWh for the hour; and
- *higher up-front cost of arranging fuel* – generator 3's up-front cost to arrange fuel in advance of the operating day is now $1,200.

The first assumption will make a reserve shortage *possible* in the context of Example 2, and produce higher market prices even if the generator arranges fuel in advance of the operating day. The second assumption is related to the first: if a market may produce higher prices even in 'good' cases when the generator has fuel, then the misaligned incentives problem tends to arise when there are higher up-front costs to arrange that fuel. In other words, the second assumption helps better reveal the misalignment problem, given the first assumption.

Broadly, with these two revised assumptions, we have created a more "stressed system" situation in the scenario when real-time demand is high. We will see again that Generator 3 would make the same decision as before to not arrange fuel in advance, based on its own expected net revenue, yet the system would be better off if it did; the outcomes would be more cost-effective and would reduce reliability risk.[41]

[41] To simplify the analysis, in Example 2-R, we will ignore the additional settlements associated with the Pay for Performance market rules that apply during a reserve shortage, which would come into play in the high-demand scenario below. Under the assumptions for Example 2-R, the PFP performance incentives would likely change the generator's decision discussed next (we omit the supporting calculations here). As noted in Section 2.4.1, PFP therefore helps address this reliability risk. However, as illustrated earlier (see Table 2-4), if we revised the present example's probabilities so that there is a sufficiently lower chance of a reserve shortage, then, as illustrated, PFP would not fully resolve the misaligned incentive problem. The reasons are the same as those discussed following Table 2-4 in Section 2.4.2.

Case A: Generator 3 arranges fuel. First consider the market outcomes if Generator 3 does arrange for fuel in advance of the operating day. The day-ahead market outcomes are unchanged from Figure 2-1 previously; the day-ahead LMP is again $30/MWh, set by marginal Generator 2. The total reserve available in the day-ahead market solution is 80 MWh, as before, which (just) satisfies the (revised) expected real-time reserve requirement. (Note that, under the current energy market design, the generators are not compensated for that reserve capability in the day-ahead market).

Table 2-9 summarizes the day-ahead and real-time market outcomes when Generator 3 arranges fuel in advance of the operating day. Row [6] shows that the higher reserve requirement (80 MWh) leads to positive real-time reserve prices in the medium and the high-demand scenarios, and therefore higher production costs and energy prices in those scenarios. Row [9] shows the system's expected total production cost is $5,267 (rounding to the nearest dollar). Row [11] reports the expected total market settlement of $7,967 (rounding to the nearest dollar).

Table 2-9. Market Outcomes for Example 2-R, Case A: Generator 3 With Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	90	10
[3]	Gen 3	0	-	0	30	0	30	20	30
[4]	Gen 4	0	-	0	40	0	40	0	40
[5]	**Totals**	190	-	170	90	190	80	210	80
[6]	**Clearing Price**	$30	-	$30	$0	$40	$10	$90	$60
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,000	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$5,267**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$6,500		$12,300	
[11]	**Expected Total Market Payments**					**$7,967**			

Case B: Generator 3 does not arrange fuel. Now consider the market outcomes if Generator 3 does not make arrangements for fuel in advance of the operating day. In this situation, the real-time market outcomes are unchanged in the low and medium demand scenarios. The high-demand scenario is different from Case A, however. In this scenario, Generator 3 would not be able to obtain fuel to operate (by assumption) and would be unavailable. Therefore, the real-time dispatch would instead use the next higher-price resource, Generator 4. Figure 2-6 shows the real-time market outcomes in this high-demand scenario. Here, the remaining capability on the system (of

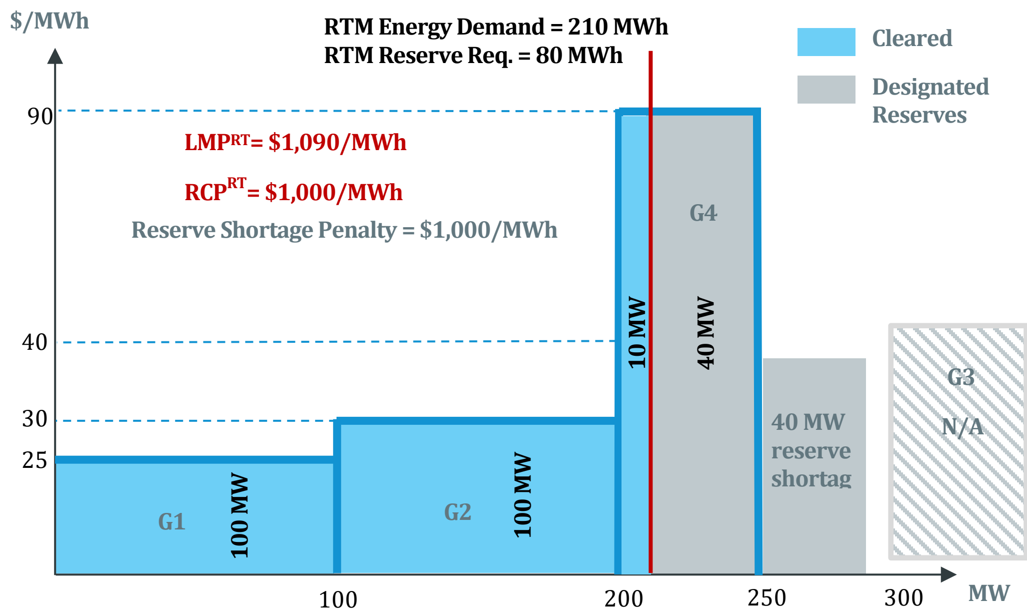

Figure 2-6. High demand scenario real-time market outcomes for Example 2, Case **B**

Generator 1, 2, and 4) is not enough to cover the total energy and reserve requirement, and there is a reserve shortage of 40 MWh.

Table 2-10 below summarizes the day-ahead and real-time market outcomes when Generator 3 does not arrange fuel in advance of the operating day. The outcomes that differ from Case A in Table 2-9, when Generator 3 has arranged fuel, are in the cells shaded in light orange in Table 2-10. We assume here that the reserve clearing price is $1,000 per MWh in the high-demand scenario with the reserve shortage. Row [9] shows the system's expected total production cost is $18,733 (rounding to the nearest dollar), which incorporates the cost of the reserve shortage at its market price signal of $1,000. Row [11] shows the expected total market settlement of $26,367 (rounding to the nearest dollar).

Table 2-10. Market Outcomes for Example 2-R, Case B: Generator 3 Without Fuel									
		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	0	0
[4]	Gen 4	0	-	0	40	0	40	10	40
[5]	**Totals**	190	-	170	90	190	80	210	40
[6]	**Clearing Price**	$30	-	$30	$0	$40	$10	$1,090	$1,000
[7]	Scenario Total Production Cost			$4,600		$5,200		$46,400	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$18,733**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$6,500		$67,500	
[11]	**Expected Total Market Payments**					**$26,367**			

► **Cost-effective outcome from society's perspective.** In Example 2-R, when Generator 3 has not arranged in advance for fuel to operate, the system's expected total production cost, including the reserve shortage of 40 MWh at its shortage price, is $18,733. When Generator 3 does arrange in advance for fuel, which prevent the reserve shortage, the system's expected total production cost is $5,267. This is a vast difference that is more than enough to cover the $1,200 up-front cost of the fuel arrangements. Thus, the most efficient outcome is if Generator 3 arranges fuel in advance of the operating day.

► **The generator's decision.** Now compare Generator 3's expected net revenue in each case, and whether its incentive to arrange fuel in advance is consistent with the efficient, most cost-effective outcome for the system.

The full settlement outcomes for Generator 3 are detailed below in Table 2-11. In brief, if Generator 3 does not arrange fuel, its expected net revenue is $100, as shown in the bottom-right cell in row [10] of Table 2-11. If it does arrange fuel, it is once again in the red, incurring a $167 net loss, as shown in the bottom-left cell of row [10].

The point here is again simple. The current energy and real-time-only reserve market design does not provide proper incentives for Generator 3 to incur the high up-front $1,200 cost of arranging energy supplies in advance, but it would both be cost-effective from society's standpoint and reduce the system's reliability risk if it did.

Table 2-11. Generator 3's Expected Net Revenue for Example 2-R, Under Status Quo/Existing Rules

			Case A: Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Real-Time Energy Deviation	*RT LMP*(Qe_RT - Qe_DA)*	$ -	$ -	$ 1,800	$ -	$ -	$ -
[3]	Real-Time Reserves	*RT RCP * Qr_RT*	$ -	$ 300	$ 1,800	$ -	$ 300	$ -
[4]	**Total Settlement**	[1]+[2]+[3]	$ -	$ 300	$ 3,600	$ -	$ 300	$ -
Generator's Costs								
[5]	Advance Fuel	*F*	$ (1,200)	$ (1,200)	$ (1,200)	$ -	$ -	$ -
[6]	Variable Cost	*MC*	$ -	$ -	$ (800)	$ -	$ -	NA
[7]	**Total Cost**	[5]+[6]	$ (1,200)	$ (1,200)	$ (2,000)	$ -	$ -	$ -
Generator's Expected Profit								
[8]	Scenario Net Revenue	[4]+[7]	$ (1,200)	$ (900)	$ 1,600	$ -	$ 300	$ -
[9]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[10]	**Expected Net Revenue**	SumProd [8]*[9]		**($167)**			**$100**	

2.9 Implications and Summary

We now consider some of the broader insights illustrated in Example 2, and connect those insights back to the energy gaps, and essential reliability services used to fill them, as discussed in Sections 2.6 and 2.7 above.

First, Example 2 illustrates a market inefficiency with the current energy market design. Generator 3's market incentives are to *not* incur the costs of arranging fuel in advance of the operating day, but society would be better off if it did. In plain terms, the current market design does not incent cost-effective outcomes.

Revisiting the three root causes of this market inefficiency discussed in Section 2.5 above as they apply to Generator 3 in Example 2:

Root Cause 1: **Generator 3 faces significant production uncertainty** – after all, there is only a 33% chance it will be in demand the next day.

Root Cause 2: **Generator 3 faces significant, irrevocable up-front costs** (of $150), relative to its expected gross margin (which, in this example, is zero); that leaves it with no infra-marginal revenue to cover the up-front cost.

Root Cause 3: **Generator 3's decision to invest in fuel arrangements – or not – is material.** It impacts the resulting market price for real-time energy (with some probability). Making the advance fuel arrangements would enable it to produce in the high-demand scenario, rather than forcing the system to use the next higher-cost resource in the supply stack (Generator 4, and, in the more stressed case, with a reserve shortage).

Thus, in incurring the private cost of investing in energy supply arrangements in advance of the operating day, the generator cannot recoup that investment in the current energy market design. However, that same investment would produce more than enough savings in expected total system production costs to make it efficient and cost-effective for the system overall. This difference between the private benefits of the investment (to Generator 3) and the expected total production cost savings (to society) results in the misaligned incentive problem, and higher expected costs to society as a result.

Second, Example 2 is structured to illustrate why the three root causes are of potential concern for the resources that the system relies upon to provide the essential reliability services itemized in Section 2.6.1 above. Generator 3 is extra-marginal in the day-ahead market and does not have a day-ahead award, which is characteristic of the resources the ISO relies up for those three operational capabilities each day. Generator 3 has slim energy market gross margins (infra-marginal revenue) on the occasions when it is dispatched for energy, providing little revenue with which to recoup – and therefore little financial incentive to incur – the up-front cost of arranging fuel in advance. And yet, during stressed system's conditions, Generator 3's operation is essential to prevent the system from needing to turn to much higher-cost generators to meet demand (and, in extreme cases, to avoid a reserve shortage).

Third, Example 2 also shows why these root causes do not apply (or do not apply to nearly the same extent) to the system's lower cost, more efficient resources that clear in the day-ahead market. Imagine, for example, that the low-cost Generator 1 and higher-cost Generator 3 in Example 2 both faced a similar $150 cost of arranging fuel in advance of the operating day. The efficient outcome would also be for Generator 1 to incur that cost. Would it be financially incented to do so, under the current energy market? *Yes*. In Example 2, Generator 1 makes a $500 gross margin *in the day-ahead market*, easily enough to motivate – and recoup the cost of – a $150 up-front cost of arranging its fuel in advance of the operating day. This logic, though simplified in the context of Example 2, mirrors the real-world economic rationale for why the ISO has not observed significant problems with gas-fired resources that clear *in the day-ahead market* failing to have sufficient fuel to meet their day-ahead energy market awards.

Last, from a reliability perspective, Example 2 illustrates that the system is potentially relying upon resources for reserves that may not be able to obtain fuel if dispatched for energy during the operating day. In Example 2, Generator 3 does not *expect* to operate and it *plans* to acquire fuel if dispatched (when it does not arrange fuel in advance, as illustrated in Case B in Section 2.8.1). From Generator's 3 perspective, it is not financially prudent to incur the costs of arranging fuel in advance, knowing that the arrangement most likely will not be used. However, as a result, based on the day-ahead market outcome in Example 2-R (Figure 2-5), the ISO would anticipate having 80 MWh of reserves when preparing the next-day operating plan – even though Generator 3 may not be able to operate.

In sum, as Example 2 illustrates, for the resources to which the three root causes above reasonably apply, it is logical to be concerned that the region may find these resources do not have sufficient energy supply arrangements if called during the operating day. And these conclusions help to explain why the region's existing wholesale market construct requires new solutions to address the reliability concerns detailed in the accompanying Brandien Testimony.

Our broad conclusion from these observations is that those resource owners are acting rationally given the operating uncertainties and difficult economic circumstances they face. The problem lies in the existing energy market design. The current energy and ancillary services markets have not changed, in their fundamental product suite, for about fifteen years; and they were not designed in anticipation that the three root causes identified above would present a material issue for a significant portion of the generation fleet.

Crucially, the misaligned incentives problem that these three root causes precipitate is not likely to solve itself. Rather, we expect it is apt to become worse, given the evolving resource mix in New England's power system and the greater operational uncertainties associated with ever more just-in-time energy sources. Therefore, and consistent with the Commission's direction, the ISO concludes that it is important "to develop longer-term market solutions" that will better align these incentives.[42] With the appropriate market design changes, generators should find it in their private interest to invest in additional energy supply arrangements whenever those arrangements would be a cost-effective means to reduce the system's reliability risk.

[42] July 2, 2018 Order at P 54.

3. Objectives and Design Principles

To understand the longer-term market solutions being implemented to address these problems, it is useful to proceed from a concise set of design objectives and principles. Specifically, the ISO's approach to developing these solutions reflects the following objectives and design principles.

3.1 Three Central Objectives

In concise terms, the ISO identified three central objectives that define the desired outcomes for both near-term and longer-term regional energy security improvements. These are:

1. **Risk Reduction.** Reduce the heightened risk of unserved electricity demand when the region's just-in-time generation technologies are limited by fuel infrastructure constraints, adverse weather conditions, or both.

2. **Cost Effectiveness**. Improve the region's competitive energy markets to achieve this risk reduction cost-effectively.

3. **Innovation.** Provide clear incentives for all capable resources, including new technologies, that can reduce this risk effectively over the long-term.

We anticipate that this third objective will become increasingly important over time, as the region's older (non-gas-fired) generation facilities reach the end of their service lives and as the New England states work steadily to advance their de-carbonization goals.

Based on the analysis of problems and root causes above, the solution presented here achieves these broad objectives through three tangible means. First, it strengthens generation owners' financial incentives to undertake more robust energy supply arrangements, when cost-effective. That requires innovative solutions, and directly addresses the misaligned incentives problem.

Second, it does not prescribe what form those supply arrangements may take. As technology evolves, suppliers will possess the best information as to what means of bolstering their energy supply arrangements will prove most cost-effective. We view that approach as consistent with all three objectives above.

Third, the solution presented here will better reward resource flexibility that helps manage, and prepare for, energy supply uncertainties during the operating day. These uncertainties may well become more challenging over time, given the increasingly just-in-time nature of New England's power system. Making these improvements through competitive, transparent market mechanisms that reward all capable resources – regardless of technology – serves all three central objectives above.

3.2 Design Principles

In developing market improvements to achieve these three objectives, the ISO focused on four core design principles. These design principles usefully circumscribe the means through which the foregoing objectives will be achieved.

Design Principle 1: **Product definitions should be specific, simple, and uniform.** The same well-defined product or service should be rewarded, regardless of the technology used to deliver it. Simplicity in product definitions enhances competition and participants' understanding.

Design Principle 2: **Transparently price the desired service.** A resource providing an essential reliability service (for instance, a call on its energy on short notice) should be compensated at a transparent price for that service.

Design Principle 3: **Reward outputs; do not specify inputs.** Compensating for obligations to deliver the output that a reliable system requires creates a level playing field for competitors that deliver energy reliably. This rewards suppliers that reduce risk in the most cost-effective ways, and fosters innovation in new solution technologies.

Design Principle 4: **Compensate all resources that provide the desired service similarly.** Paying similar rates for similar service is non-discriminatory by fuel-type or technology, and sends the broadest-possible market signal for the desired attribute.

These are familiar, not novel, principles for economically-sound market design. They help to ensure that the tangible solutions developed will be robust and will continue to function properly as the markets' fundamentals change over time.

Indeed, as the economic environment evolves, a good solution will not need to be continually revisited, and its market rules will not need to be successively perturbed. Achieving that requires a solution that employs sound economic principles, integrates well with the existing wholesale market structure (both from a technical standpoint for the ISO, and from a commercial standpoint for participants), and minimizes administrative rules, restrictions, and parameters whose appropriateness may not persist as the system evolves.

Ultimately, the market design solution we discuss next should help to allay the tensions that have emerged over New England's energy security challenges in recent years, and provide sustainable benefits to the region's competitive wholesale marketplace by adhering to these familiar market design principles.

4. Solution Concepts: Energy Options

In this section, we discuss the conceptual logic of a long-term market solution to the problems detailed in Section 2, and that achieve the objectives in Section 3. The overall design approach builds upon familiar energy and ancillary service concepts used in the wholesale electricity markets. Broadly, the Energy Security Improvements expand the existing suite of energy and ancillary service products in the ISO-administered markets, in order to address – reliably and cost-effectively – the uncertainties and supply limitations inherent to a power system evermore reliant on just-in-time energy technologies.

Specifically, the Energy Security Improvements introduce a new set of products in the day-ahead markets that help to better address the region's fuel security concerns, while being closely aligned with the power system's existing reliability requirements. These new products take the form of several new ancillary services in the day-ahead market. Importantly, the settlement design for these ancillary services is both intuitively natural and, on close inspection, provides an economically sound solution to the misaligned incentives problem detailed above in Section 2.

At a high-level, the design provides the ISO with the option to "call" on the energy of an ancillary service seller during the operating day, above and beyond its day-ahead energy schedule (whether or not it has one), in amounts and over timeframes that are carefully designed to match the specific essential reliability needs detailed in Section 2.6. Moreover, the design will also tend to increase the total compensation for energy sold in the day ahead market as well, further increasing the incentives for all suppliers to ensure they have sufficient energy supply arrangements to operate as scheduled in real-time.

In this section, we address the rationale, properties, and conceptual logic for a call option on resources' energy during the operating day to satisfy the requirements for a set of new day-ahead ancillary services. We provide simple illustrative examples in this Section 4, and more detailed design examples and analysis in later sections of the paper.

4.1 Key Components and Rationales

Developing new products in the wholesale electricity markets requires careful attention to details such as resources' offer formats, requisite capabilities, settlement processes, and so forth. Here, we provide a higher-level overview of the key concepts and properties of the new day-ahead ancillary services.

Our immediate purpose is to provide conceptual clarity on the design, rationale, and the role of energy options in ancillary services' settlements. Later, in Sections 6 and 7, we will provide additional detail on product-specific pricing, clearing, and other design elements, as well the associated new Tariff provisions.

► **Product definitions.** At a high level, a day-ahead seller of the new ancillary services introduced by the Energy Security Improvements (each of which will be described specifically below) is providing the ISO with a “call” on its resource’s electric energy (*i.e.,* its output) during the operating day. A generator that provides these services would have both a day-ahead and a real-time settlement for the hours for which it acquires a day-ahead ancillary services obligation. Different time-related parameters (*e.g.,* generator ramp or startup times) are relevant to the different ancillary service products, but apply similarly to all sellers of the same product.

This approach to the product definition is intended to be specific, simple, and uniform (Design Principle 1, as discussed in Section 3.2) and it (rewards the output capabilities the system requires, not suppliers’ inputs (Design Principle 3). Moreover, it will help to achieve all three of the central objectives described in Section 3.1.

► **Pricing and compensation.** The market clearing process for the expanded day-ahead energy and ancillary services (E&AS) market will compensate both energy and ancillary services at uniform, transparent, product-specific market prices. This serves to satisfy Design Principles 2 (price transparency) and 4 (non-discrimination).

The clearing prices of these day-ahead ancillary services will vary over time (*i.e.,* each hour), as their supply and demand dictate. In this way, the pricing serves to reward the resources that are the most cost-effective suppliers of each product for any given hour. Importantly, the clearing prices of each day-ahead product account for the *inter-product opportunity cost* that can arise if a seller is awarded one particular day-ahead product instead of a different day-ahead product for the same delivery hours (more about which presently).

► **Participation.** Offers to provide these ancillary services are voluntary, consistent with the mission of the ISO “to provide market rules that . . . promote a market based on voluntary participation … [for] any required service.”[43] This allows resource owners to continue to sell just energy (and not to sell day-ahead ancillary services), if they expect that doing so is their most profitable opportunity in the ISO’s revised day-ahead energy and ancillary services markets. The ISO’s regulation ancillary service market, for example, operates on a similar premise.

At the opposite end of the participation spectrum, a resource owner that wishes to submit day-ahead offers to sell energy and one or more of the new day-ahead ancillary services would be free to do so. If submitted, however, an energy option offer must be accompanied by an energy supply offer from the same physical resource, to ensure the resource’s physical characteristics and offer prices can be appropriately accounted for in the market clearing process (more about which below).

► **One offer, multiple products.** Under the new design, resources will submit a single energy option offer. That offer may be cleared, in the day-ahead market, for energy imbalance reserve, generation contingency reserve, or replacement energy reserve – the three new day-ahead ancillary services, discussed in detail below. That is, a market participant does not submit separate option offers for each type of ancillary service; it submits a single offer, and the market clearing process determines how that offer (and the physical capabilities of the associated resource) can most cost-effectively serve the system’s day-ahead ancillary service requirements. This feature of the clearing

[43] Tariff Section I.1.3(c).

process is important in order to avoid "double-award" problems (*i.e.,* this avoids awarding multiple obligations to the same MW of a seller's resource's capability in the same delivery hour).

This 'one offer, multiple products' system simplifies the overall design. Moreover, it is economically sensible because each product is identically settled, as an energy call option, based on the real-time energy price (discussed further in Section 4.3 below). Equally importantly, using this 'one offer, multiple products' design means that every offer can be substituted, by the clearing engine, to meet any of the new day-ahead ancillary service requirements (up to the physical limits of the associated resource). That substitutability enhances the overall competitiveness of the day-ahead ancillary service market, since each offer effectively competes (up to the limits of the resource's physical capability) with the 'full pool' of all other energy option offers.

► **Physical capabilities.** Day-ahead ancillary service awards are associated with specific physical resources, and the market clearing process is expressly based on resources' physical operating characteristics. For example, a resource's day-ahead 10-minute ancillary service product award depends upon (and is limited by) the resource's 10-minute ramping capability (or, if scheduled to be offline for the hour, its 10-minute startup capability). More generally, resources' time-related physical capabilities (ramp rates and startup times) will determine, in part, their day-ahead market awards for these time-differentiated ancillary service products.

Note that a resource's ramping capability and scheduled on- or off-line status depend on its energy award for the hour. For example, a resource that is economically scheduled to supply energy at its maximum physical energy production level in the day-ahead market has no additional production capability with which to provide reserves. The day-ahead market clearing process, which will be jointly performed for energy and all ancillary services simultaneously, accounts for these physical resource capabilities and limits.

► **Day-ahead co-optimized clearing.** To ensure cost-effectiveness, the award of all day-ahead ancillary services will be co-optimized (*i.e.*, simultaneously cleared) with participants' day-ahead energy supply and demand awards. That will enable the market-clearing process to determine the most cost-effective assignment of resource offers to awards for all products.

That co-optimization process ensures, by design, that the clearing price for each ancillary service product will incorporate the (marginal) suppliers' opportunity costs of not receiving an award for a different day-ahead product. It also means that the day-ahead prices for energy will depend, in general, upon the clearing prices for the ancillary services as well. In that respect, the day-ahead market will share many of the pricing properties presently found in the ISO's co-optimized real-time energy and operating reserve markets.

With these key concepts in hand, we next introduce the specific new ancillary service products.

4.2 New Ancillary Service Products in the Day-Ahead Markets

Section 2.6 described three essential reliability services that the system relies upon, above and beyond resources' day-ahead energy market awards, to prepare for and to help manage the potential energy 'gaps' that can arise in the next-day operating plan. The Energy Security

Improvements formalize these three categories of operational requirements into specific ancillary service capabilities, and allow resources to compete to provide those capabilities in an expanded day-ahead energy and ancillary services market. Broadly, the purpose is to improve today's market construct so that the future resource mix will undertake additional energy supply arrangements, and pursue addition of new technologies, that will ensure these essential capabilities remain available to the power system each operating day.

In concrete terms, these three categories of day-ahead ancillary services are:

A. **Energy Imbalance Reserves.** Energy imbalance reserves are a new product to be procured in the day-ahead E&AS market. It serves a simple purpose: to provide the ISO with sufficient energy "on call" to cover the forecast load imbalance – that is, the 'gap' – when the total energy cleared in the day-ahead market from physical supply resources (*e.g.,* generation and net imports) is less than the ISO's forecast energy demand, in one or more hours, for the next (operating) day.

   Energy imbalance reserves are important because the ISO's forecast energy demand for each hour of the next operating day frequently (but not always) exceeds the total bid-in energy demand, and therefore total cleared supply, in the day-ahead energy market. Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast load each hour – not simply the level of demand cleared in the day-ahead energy market.[44]

   Importantly, energy imbalance reserve is in addition to, and distinct from, the capabilities necessary to ensure that the system is prepared to handle supply-loss contingencies and replacement energy – the new ancillary services that address those needs are discussed next.

B. **Generation Contingency Reserves.** Generation contingency reserves refers to three resource capabilities that the ISO currently designates and maintains in the real-time market for operating reserves. These are ten-minute spinning reserves (TMSR), ten-minute non-spinning reserves (TMNSR), and thirty-minute operating reserves (TMOR). In simpler terms, all three are forms of fast-start or fast-ramping generation capability.

   The ISO relies upon these capabilities to ensure the system is prepared to promptly restore power balance (consistent with the timeframes established in applicable reliability standards) in response to a sudden, unanticipated power supply loss during the operating day.[45] Under the Energy Security Improvements, the ISO will procure, and compensate for, these same three fast-start or fast-ramping capabilities in the day-ahead E&AS market.

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[44] *See* Brandien testimony at pp. 18-19.

[45] *See* Brandien Testimony at pp. 7-8.

C. **Replacement Energy Reserves.** Replacement energy reserves are new products to be procured in the day-ahead E&AS market. At a high-level, these reserves will provide the ISO with the option to "call" on the energy of an replacement energy reserve resource, above and beyond its day-ahead energy market award (whether or not it has one), over specific timeframes of more than an hour (*e.g*., energy to be provided within 90 minutes, or within four hours).

The ISO relies on replacement energy reserve capabilities to provide the energy needed to replace a day-ahead cleared resource that is unexpectedly unable to operate for an extended (multi-hour to multi-day) duration. In practice, the ISO can rely on the generation contingency reserve resources (those described in category B in Section 2.6.1) for energy for only a limited amount of time after a contingency (*e.g.,* a few hours or less – a duration that may vary with resource availability, demand, and other operating day conditions). After that point, the replacement energy to cover a contingency's balance-of-day energy gap must come from the dispatch and commitment of other resources operating above and beyond their day-ahead awards.

Under the Energy Security Improvements, the ISO will procure two types of replacement energy reserves in the day-ahead E&AS market: ninety-minute replacement energy reserve (RER90) and four-hour (240 minutes) replacement energy reserves (RER240). These two products are designed to align closely with the specific timeframes prescribed in existing reliability standards for the restoration of Generation Contingency Reserves – which, in turn, requires sufficient replacement energy, on those specific same timeframes, to restore the system's generation contingency reserve to reserve (non-energy-producing) status.[46]

For the resources that the ISO relies upon for these three essential reliability services, the design of these day-ahead products directly addresses the misaligned incentives problem explored previously in Section 2. That is, the new design seeks to better align incentives so that generators will choose to invest in additional energy supply arrangements when those arrangements are a cost-effective means to reduce the system's reliability risk.

Specifically, Section 2 identified three inter-related problems that help explain the region's energy security risks and the need for market design improvements: misaligned incentives (Problem 1), operational uncertainties (Problem 2), and insufficient day-ahead scheduling (Problem 3). The first of these new day-ahead ancillary services, energy imbalance reserves, addresses Problems 1 and 3. The latter two of these new services, generation contingency reserves and replacement energy reserves, help the system to manage uncertainties that can arise during the operating day by addressing both Problems 1 and 2. Taken together, these day-ahead market ancillary services will provide, and compensate for, the flexibility of robust, reliable energy supplies 'on demand' to manage uncertainties each operating day.

[46] *See* Brandien testimony at pp. 11-17.

Other notable features of the new day-ahead ancillary services include:

► **The day-ahead load forecast.** To procure only the minimum energy imbalance reserve necessary each day, the ISO will incorporate the system's forecast load into the day-ahead E&AS market clearing process. Conceptually, the quantity of energy imbalance reserve procured for each hour of the next operating day will be (just) enough to fill the 'gap' (when positive) between the day-ahead forecast load for the hour and the amount of physical energy supply that clears in the day-ahead market.

In New England, the day-ahead market presently clears (nearly) always on the price-sensitive portion of market participants' aggregate energy demand curve. Under the new day-ahead E&AS market, when the price of energy is low, the market will tend to clear more energy and the forecast load-imbalance 'gap' will tend to be small (or zero); in that case, the day-ahead E&AS market will procure relatively little (or zero) energy imbalance reserve. At other times, when the market clears less energy, more energy imbalance reserve will be procured in order to cover the system's next-day load forecast. In this way, the specific balance of energy imbalance reserve and physical energy supply cleared in the co-optimized day-ahead market will be jointly (*i.e.,* simultaneously) determined, in conjunction with all other bids, offers, and ancillary service requirements.

From an economic perspective, incorporating the load forecast into the day-ahead E&AS market effectively creates another demand "curve" for energy – that is, *in addition to* the demand for energy comprised of market participants' aggregate day-ahead bids to buy energy. The additional source of demand will, in general, increase the compensation to *all* supply resources scheduled for energy in the day-ahead market. This additional compensation will be transparently and uniformly priced, as a new component of the day-ahead market's compensation to supply resources scheduled to provide energy. We discuss this important component of our co-optimized day-ahead market design in detail in Section 6.

► **Other Ancillary Service Demand Quantities.** The demand quantities to be cleared for each new day-ahead ancillary service product reflect the requirements of a reliable next-day operating plan, as summarized earlier in Section 2.6.3. Those demand quantities are based on existing reliability standards.[47]

In practice, the MWh of ancillary services necessary to satisfy those next-day operating requirements are inherently dynamic, varying day-by-day and hour-by-hour based (in large part) on the forecast demand profile, the generation cleared for energy in the day-ahead market, and the system's largest energy-source losses (*i.e.,* contingencies) during the course of the operating day. We provide additional detail on these demand quantities in Sections 6.1.2 and 7.3.

► **Product substitution.** Conceptually speaking, there are many possible assignments of resources' capabilities to the system's day-ahead ancillary service products. For instance, a generator that is capable of providing generation contingency reserve, but that is not cleared as generation contingency reserve (economically) for a particular delivery hour, might instead be economically

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[47] *See* Brandien Testimony at pp. 26-30.

cleared to supply replacement energy reserve. The reverse is not necessarily true (*e.g.,* depending on a resource's startup-time or ramp-rates, a resource that can provide replacement energy reserve may not be capable of supplying generation contingency reserves).

At a different level, the capabilities procured for generation contingency reserve can, for a period of time after a contingency, potentially serve to meet some of the system's replacement energy reserve requirements during the same hours. The details of these relationships, which can be quite technical, are formally known as the *product substitution* structure. These relationships impact both the efficient pricing and clearing of ancillary services, and are addressed in detail in Section 7.2.

► **Real-time remains least-cost dispatch.** Because suppliers in the New England markets have the ability to update their energy supply offer prices ("re-offer") when their costs change during the operating day, the least-cost solution to the system's real-time energy and reserve requirements during the operating day may be different than the day-ahead solution. Thus, the dispatch of energy and the designation of real-time reserves, and the economic evaluation of any additional commitments (whether fast-start or otherwise) after the day-ahead market, will continue to be performed based on the resource offers in effect in real-time. The real-time dispatch of the system would continue to perform co-optimization of energy and operating reserves, as is the case today.

► **Energy options, not daily forward reserves.** All of the new day-ahead ancillary services – energy imbalance reserve, generation contingency reserve, and replacement energy reserve – will be settled as call options on real-time energy. This means that the day-ahead market will procure options on real-time energy from physical resources; not ancillary services that settle against resources' anticipated real-time reserve designations.

To clarify that point, note that the ISO also maintains real-time contingency reserve products (day-ahead TMSR, TMNSR, and TMOR) in the real-time market (namely, real-time operating reserve designations of resources' unloaded capability that can ramp up, or startup from an offline state, to deliver additional energy within 10 or 30 minutes). The day-ahead generation contingency reserve product awards will not settle against the real-time prices for these real-time reserve designations, however. Rather, day-ahead generation contingency reserve awards will be settled, using standard options settlement rules, against the real-time price of *energy.*[48]

The reason we have designed New England's day-ahead ancillary services as options on real-time energy is the strong incentives this design creates. Specifically, the incentives for resources to arrange more robust energy supply (*i.e.,* fuel) arrangements are superior – *i.e.,* more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward sale of real-time reserve designations. We explain

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[48] Note that there is no real-time analog to the energy imbalance reserve product, as that ancillary service exists to align day-ahead market's results with the system's day-ahead forecast load. In addition, unlike generation contingency reserve, at present there are no 90-minute or 4-hour replacement energy reserve products in New England's real-time markets. Creating replacement energy reserves in the real-time markets is a possible future market design enhancement that would require additional development work, and is beyond the scope of the present filing.

the settlement of energy options in Section 4.3 next, and then address the beneficial incentives that it provides, in detail, in Section 5.

4.3 Settlement of Day-Ahead Ancillary Service Awards as Energy Options

A central feature of the new ancillary services' design is their settlement. Consistent with the conceptual logic of providing the ISO with a call on a resource's energy "on demand" during the operating day, the Energy Security Improvements will settle resources' day-ahead ancillary service obligations as a call option on real-time energy. Accordingly, each day-ahead ancillary service award will have two-settlements: one day-ahead and a second based on the price of real-time energy.

This settlement design applies a familiar, standardized multi-settlement rule that is used in a wide variety of physical commodity markets. Moreover, it functions well in concert with the existing day-ahead energy market's two-settlement design. The second (real-time) settlement is slightly different for day-ahead energy and for ancillary service positions, however, reflecting that the former is a *forward* sale (or purchase) of real-time energy and the latter is an *option* on real-time energy.

Importantly, although the day-ahead ancillary service obligations will have financial consequence, they are not "financial options." Rather, they are real options on energy – in the formal sense that their award is dependent on a resource's physical operating characteristics, and a resource's net settlement is expressly dependent on what it physically produces in real time. This real option design creates new incentives for sellers of these ancillary services to ensure they have the physical wherewithal (including fuel) to cover their obligations the next day. This is because a resource that commits to providing one of these new ancillary services will face a financial consequence in real-time settlement if the real-time energy price is high and the resource does not perform. At the same time, resources will receive day-ahead compensation to cover their costs of additional energy supply (*e.g.,* fuel) arrangements, even if it turns out that they are not needed to operate the next day.

These product design and settlement features fundamentally change the incentives present today. From a commercial standpoint, it will become profitable for the resources that the ISO relies on for these ancillary capabilities to incur the costs of maintaining reliable fuel arrangements, when such arrangements are cost effective from the standpoint of the system overall – helping ensure they can perform if dispatched to fill an energy gap, even on a day they did not expect to operate.

To illustrate and explain these properties, below we provide a series of numerical examples. For clarity, we start with a summary of how option settlements work, as applicable in the context of the new day-ahead E&AS markets. Since the same settlement logic and rationale applies to each of the new day-ahead ancillary service products, our discussion throughout this section is equally applicable to the new day-ahead energy imbalance reserve, generation contingency reserve, and replacement energy reserve products.

4.3.1 Energy Option Settlements: Simple Examples and Implications

In today's day-ahead energy market, all energy sales (and purchases) have a second settlement. That second settlement is based on the energy produced (and consumed) in real-time and the real-time energy price. In the new day-ahead E&AS market, the day-ahead ancillary services will also have a second settlement, based on those same two elements. However, as noted above, the settlement for energy and for an ancillary service is slightly different.

In this section, we summarize the settlement mechanics for the new day-ahead ancillary services and provide several simple examples. These examples mirror the established way that call options are settled in markets that clear both forward sales (and purchases) and call options for future delivery.

► **Components and mechanics.** First, the settlement components. A call option settlement involves three elements:

- the sale of the option, which occurs at the *option price,* which we denote by V;
- the option *strike price*, which we denote by K; and
- the real-time price of the good the seller is providing an option on, which in this context is real-time energy.

The strike price is a pre-defined value, set *before* sellers specify their option offer prices in the day-ahead E&AS market. The strike price, and the level at which it is set, plays a key role in the strong incentives that this day-ahead ancillary service design creates. (We'll explain that in greater detail below.) For the moment, think of the strike price as simply a threshold price level, known to all before the option is offered and the market clears.

Like a forward sale of energy, a resource that sells an energy call option has both a day-ahead settlement, and a real-time settlement. The day-ahead option settlement has two parts. The first provides a payment to the seller at the day-ahead option clearing price, $V,$ for each MWh of the option sold. In the second, the day-ahead option award is then 'closed-out' based on the real-time price and the option's strike price. Specifically, for each MWh of the option sold day-ahead, the seller is charged the real-time LMP *minus* the strike price $K,$ if that difference is positive. In mathematical terms, this is written as:[49]

$$-\max\{0, RT\ LMP - K\}.$$

The real-time settlement is a credit, at the real-time LMP, for the MWh of energy the resource actually produces in real-time. This real-time settlement step does not depend on the option award

[49] Note settlement sign conventions here: a negative number is a charge (debit) to the participant; a positive number is a credit. This convention is followed in all the settlement tables throughout this paper.

directly, but will (more than) offset the option's close-out charge if the resource produces energy in real-time.

Here are a few simple examples.

► **Simple settlement examples.** In each case below, assume a resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = \$50 (per MWh) at an option clearing price of V = \$5 (per MWh).

First, consider several cases where the resource produces exactly 1 MWh of energy in real-time:

a) The resource produces 1 MWh in real-time and the real-time LMP is **\$60**/MWh. Its net settlement is calculated as:

$$V - \max\{0, RT\ LMP - K\} + \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$60 = \$55.$$

In this case, the resource's net settlement simplifies to $V + K$. The close-out charge and real-time credit net settlement result is a payment at the strike price, K, rather than the real-time LMP, since the real-time price is higher than the strike. In that situation, standard terminology is to say the option is "in the money."

b) The resource produces 1 MWh in real-time and the real-time LMP is **\$40**/MWh. Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \text{RT LMP}$$

evaluates as:

$$\$5 - \max\{0, \$40 - \$50\} + \$40 = \$45.$$

In this case, the resource's net settlement simplifies to V + RT LMP. The close-out charge and real-time credit net settlement results in a payment at the real-time LMP, since the real-time price is lower than the strike. In that situation, standard terminology is to say the option is "out of the money."

In summary, cases (a) and (b) show that if a resource sells 1 MWh of day-ahead ancillary service and produces 1 MWh of energy in real-time, it receives the option clearing price V and a credit of, at most, the value of the strike price K.

Next, consider a case where the resource again sells 1 MWh of a day-ahead ancillary service, but now assume it produces more than 1 MWh of energy in real time:

c) The resource produces **2 MWh** in real-time and the real-time LMP is **\$60**/MWh (*i.e.,* in the money again). Its net settlement is now:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{2\ MWh} \times \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \mathbf{2} \times \$60 = \$115.$$

In this example, the first MWh produced in real-time 'covered' the resource's day-ahead option award, and the second is simply an additional MWh sale at the real-time price. In the calculation above, the real-time settlement therefore provides a credit for the higher quantity (*i.e.*, 2 MWh) delivered in real-time at the real-time LMP.

► **Implications for day-ahead energy and ancillary service prices.** Cases (a) and (c) have an important economic implication and interpretation. In general, in exchange for the certainty of the day-ahead option payment *V*, a seller of a call option is 'giving up' its potential gain from alternatively selling in the real-time market, if the real-time price is higher than the strike price *K.* This is in contrast to its real-time settlement if it sells its day-ahead energy *forward* and delivers the same amount in real time, which would have a real-time credit of zero.

In essence, selling energy forward is giving up the entire potential gain from selling in real-time, but selling a (call) option on energy is not giving up the entire potential gain from selling in real-time, as the resource is still paid either *K* or the RT LMP, whichever is less, if it produces energy. For that reason, call options have lower offer prices than day-ahead forward energy offer prices, and call options have lower clearing prices than forward prices for the same delivered product.

► **More simple examples.** Next, consider two cases where a resource sells 1 MWh of a day-ahead ancillary service and does *not* produce energy in real-time. As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of *K* = \$50 (per MWh) at an option clearing price of *V =* \$5 (per MWh).

d) The resource produces 0 MWh in real-time and the real-time LMP is **\$60**/MWh (*i.e.,* in the money). Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

evaluates as

$$\$5 - \max\{0, \$60 - \$50\} + \$0 = -\$5,$$

for a net charge of \$5. In this case, the resource's net settlement simplifies to *V* – (*RT LMP* – *K*). The close-out is a charge to the resource*,* equal to the real-time LMP *less* the strike price, with no offsetting real-time credit since the resource produced zero energy.

In effect, in the real-time settlement in this situation, the option seller is paying for the ISO's cost of replacing its 1 MWh of energy with energy from the marginal resource in real-time (*i.e.,* a cost equal to the RT LMP), but only to the extent that cost exceeds the pre-specified strike price *K.*

e) The resource produces 0 MWh in real-time and the real-time LMP is **$40**/MWh (*i.e.,* out of the money). Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

evaluates as:

$$\$5 - \max\{0, \$40 - \$50\} + \$0 = \$5.$$

In this case, the resource keeps the day-ahead clearing price of $5 for accepting the day-ahead ancillary service obligation, and no money changes hands in later settlements. In this case, the resource's net settlement simplifies to just *V.*

In summary, cases (d) and (e) show that if a resource sells 1 MWh of day-ahead ancillary service and it produces 0 MWh of energy in real-time, it incurs a real-time charge to cover the ISO's real-time 'replacement cost' of its undelivered 1 MWh – but only to the extent it exceeds the strike price *K.*

► **Simple examples with co-optimized real-time dispatch.** Next, we consider how the day-ahead energy option settlements work with real-time reserves. The purpose of the next two cases is to show that the day-ahead ancillary services market outcomes do not change the existing co-optimized real-time market's incentives for resources to follow their assigned real-time dispatch.

The next case examines how the settlements work when a resource is designated for reserves in real-time, rather than energy. Specifically, consider a resource that is awarded a day-ahead ancillary service (of any type), and is designated for operating reserves in real-time, and then its energy dispatch in real-time is zero.

As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of *K* = $50 (per MWh) at an option clearing price of *V* = $5 (per MWh).

f) Assume the resource's real-time energy offer price is $45/MWh, the real-time LMP is $60/MWh (an "in the money" case), and the real-time reserve clearing price (RCP) is $20/MWh. The resource produces 0 MWh of energy and provides 1 MWh of reserves in real time.

In this case, its option will be settled as before in example (d), and it will be credited for its 1 MWh of real-time reserves at the RCP. Its total net settlement is:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP} + \mathbf{1\ MWh} \times \text{RT RCP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$0 + \$20 = \$15.$$

In this situation, it is economically correct that the real-time co-optimized dispatch assigned this resource's capability to real-time reserves rather than energy. This is because the real-time reserve price ($20) exceeds the resource's energy margin ($60 – $45 = $15).

Regardless of what it sold day-ahead, the resource is better off following the real-time dispatch – which, in this example, has it providing reserves instead of energy in real-time.

This case (f) illustrates an important point. Despite selling the day-ahead ancillary service (which settles as an option on *energy*), in real-time the resource is better off providing reserves than producing energy, given the real-time prices. That real-time dispatch-following property is unaffected by the sale (or not) of day-ahead ancillary services, here and generally.[50]

To illustrate that point further, note that in this example (f), if the resource had instead chosen to run in real-time (*i.e.,* to self-schedule), then it would have the net settlement of $55 as shown in earlier case (a), and a net profit of $10 ($55 – $45 cost). In contrast, in case (f), we see the resource has a higher net profit of $15 by following its dispatch instruction in real-time. We highlight this observation because the point is important: the day-ahead ancillary services market awards do not change the existing co-optimized real-time market's incentives for resources to follow their assigned real-time dispatch.

Along a similar line, this next case considers a situation where the resource re-offers in real-time. As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = $50 (per MWh) at an option clearing price of V = $5 (per MWh).

g) The resource's day-ahead energy offer price is $45/MWh, and in real-time the resource re-offers energy at a price of $75/MWh. The real-time LMP is $60/MWh, and the real-time RCP is $0/MWh. The resource produces 0 MWh of energy in real-time (as its real-time energy offer price exceeds its RT LMP).

   In this case, its option will be settled as before in case (d). Its net settlement is:

   $$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

   which is:

   $$\$5 - \max\{0, \$60 - \$50\} + \$0 = -\$5.$$

   In this situation, the real-time dispatch produces an efficient outcome (given the RT LMP) in which the resource is 'buying out' its day-ahead ancillary service position in real-time, at a cost of $RT\ LMP - K = -\$10$. That buy-out cost is less than the resource's cost if it produced energy facing the same prices, which would result in a real-time loss of $RT\ LMP - RT\ Offer$ = $60 – $75 = – $15.

► **Buying-out when production is uneconomic.** This case (g) has a useful economic implication in situations where a day-ahead ancillary service seller has high marginal costs for energy (in real-time), and therefore in real-time its energy production is uneconomic. In such cases, having

[50] Note that, if the RCP was lower (say, $10) in this example, the real-time co-optimized dispatch would have dispatched this resource for energy and not designated it for real time reserves, because its opportunity cost of energy ($60 LMP - $40 offer cost) would exceed the RCP.

acquired a day-ahead ancillary service obligation (which settles as an option on *energy*), in real-time the resource is better off following an assigned real-time dispatch to produce zero and thereby 'buying out' its day-ahead obligation than producing energy to match its day-ahead option award.

That is true generally, whether or not the resource re-offers due to a change in (say) its fuel costs from day-ahead to real-time. We assumed it re-offers its energy at a higher price here simply to illustrate an outcome that can (and likely will) happen to resources that re-offer in practice – and showed that the market design produces the economically correct real-time incentives in this circumstance. Note that this situation is conceptually analogous to what happens today when a resource sells energy day-ahead (rather than an option on energy), and is dispatched down in real-time below its day-ahead award – it 'buys out' its day-ahead position, in a way that preserves its incentives to follow the real-time dispatch.

► **Replacement cost-based settlements.** Next, consider a case in which a resource sells 1 MWh of a day-ahead ancillary service and does *not* produce energy in real-time. Here, we'll assume the real-time energy price is high, so the unit would be in-merit if it were able to produce, but that (for any number of possible reasons) is it not able to operate in real-time.

As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = \$50 (per MWh) at an option clearing price of V = \$5 (per MWh).

h) Assume the resource's real-time energy offer price is \$70/MWh, the real-time LMP is now \$400/MWh, and the real-time reserve clearing price (RCP) is \$0/MWh. The resource produces 0 MWh of energy in real-time.

   In this case, its option will be settled as before in cases (d) and (g), but its net settlement is a now a much larger charge because the RT LMP is higher. Its total net settlement is:

$$V - \max\{0, \mathit{RT\ LMP} - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

   which is:

$$\$5 - \max\{0, \$400 - \$50\} + \$0 = -\$345.$$

   In this situation, the resource would be dispatched if available (as its energy offer price is less than the RT LMP). Because it is not able to operate, however, it is again 'buying out' (as in case (g)) its day-ahead ancillary service position in real-time. Since the real-time LMP is high, this comes at a steep financial consequence of $\mathit{RT\ LMP} - K = -\$350$. As a result, it incurs a net loss in real-time settlements, based on the system's high prevailing price to procure energy to replace the non-performing resource's MWh in real time.

Case (h) illustrates a key economic principle, with significant implications for sellers' incentives. In this case, the ancillary service seller is compensating the buyer (the ISO, in the immediate instance, and load, ultimately) for the replacement cost of energy that the system must incur in real-time, at the margin, if the seller cannot operate.

Though it may seem a minor detail, in these situations it is useful to note that the *incremental* replacement cost due to the ancillary service seller's non-performance is equal to *RT LMP – K,* and *not* the full value of the *RT LMP.* The economic logic here is that, when the option was purchased (by the ISO) in the day-ahead market, the system acquired the right to 1 MWh of real-time energy for an up-front price of *V,* and an incremental price of (at most) *K* in real-time. If the seller does not deliver energy in real-time, the settlement rules put the seller "on the hook" for the *incremental* cost – that is, the cost in excess of *K* – to replace its energy. In case (h), here's how that plays out:

- The marginal resource dispatched in real-time is paid, per normal real-time settlements, the RT LMP of $400/MWh to supply the 1 MWh of energy not delivered by the seller that took on the day-ahead ancillary service obligation.

- The day-ahead ancillary service seller is charged the amount *RT LMP – K* = $350 for the incremental cost (*i.e.,* in excess of *K*) to replace its energy with that of the marginal resource (which cost $400/MWh).

- The incremental price paid by the ISO for the 1 MWh of energy "covered" by its call option nets to the strike price *K*, as required:

  $400 *RT LMP for energy* – $350 *charge to the ancillary service seller* = $50 *strike.*

In that way, regardless of which resource is ultimately dispatched to supply the marginal unit of energy in real-time, the ISO (and, ultimately, consumers) acquire the 1 MWh of real-time energy at a cost of (at most) *K.* The day-ahead ancillary service seller must incur all additional costs, in excess of the strike price, to replace its energy when it does not provide energy in real-time. That incremental replacement cost borne solely by ancillary service seller is *RT LMP – K.*

► **Implications.** This replacement cost logic lies at the economic core of why call options – both in the present context and more generally – help align incentives efficiently. In particular, the obligation of a day-ahead ancillary service seller to cover its resource's incremental replacement cost at the prevailing real-time market price will strengthen such sellers' incentives to ensure their resources are able to operate reliability, relative to today's day-ahead energy market design. (That is, relative to today's day-ahead market design wherein ancillary services are not priced, nor compensated, at all).

Stated directly, in the ISO's current day-ahead market design, if a resource does not clear in the day-ahead market and does not produce in real-time, its net settlement is zero. By contrast, under the new day-ahead ancillary service design, if a resource receives a day-ahead ancillary service award and does not produce in real time when dispatched, it incurs a potentially steep financial consequence if the real-time incremental cost to replace its energy is unexpectedly high (*e.g*., during a stressed operating day). The resources that the ISO relies upon for the system's essential ancillary services in the next-day operating plan will now have significant incentives to ensure they can operate if and when dispatched during the operating day.

We will explore the incentives that this replacement-cost ancillary service market design provides further, and how it resolves the misaligned incentives problem generally, using several more detailed numerical examples in Section 5. Before doing so, however, it is useful to touch on how these energy option settlement rules work in conjunction with resources' day-ahead energy awards.

4.3.2 Day-Ahead Energy and Ancillary Service Settlements

All of the foregoing examples are special cases of a general multi-settlement system applicable when there is more than one day-ahead product. This system is particularly useful when a single resource receives both energy and ancillary services awards in the day ahead E&AS market.

Again, the settlement logic and rationale discussed below applies to each of the new day-ahead ancillary service products. Thus, our discussion here is equally applicable to the new day-ahead generation contingency reserve, replacement energy reserve, and energy imbalance reserve products.

One important point: in Section 4.2, we noted that incorporating the day-ahead load forecast into the day-ahead market will create a new source of compensation to supply resources scheduled to provide energy, and that new component will be separately priced (*see "*The day-ahead load forecast" discussion therein). That new component is not covered in this present section; we will introduce and explain it in the context of the market-clearing process for the Energy Imbalance Reserve, with the assistance of additional examples, in Section 6.

► **Example with a day-ahead energy and ancillary service award.** This next example shows the multi-settlement steps for a resource with both a day-ahead energy and an ancillary service award (awarded to different MW of the resource's capacity).

i) Assume a resource sells 1 MWh of energy and 2 MWh of an ancillary service in the day-ahead market for a particular hour the next day (again, which specific ancillary service does not matter here). During that hour (*i.e.,* in real-time), the resource produces 5 MWh of energy.

   How is this settled? The various day-ahead and real-time settlements for the two products are easiest to organize in a table, as shown below. (The day-ahead reserve clearing price, denoted in the preceding section by the price *V*, is now abbreviated RCP below). The resource's total market settlement is the sum of the five entries in the table.

	Forward Sale of Energy	Option Sale of Ancillary Service
Day Ahead Awards (credits)	2 MWh × *DA LMP*	1 MWh × *DA RCP*
Close-out of Day-Ahead Positions (debits)	–2 MWh x *RT LMP*	–1 MWh × max{0, *RT LMP* – *K*}
Real-Time Supply (credits)	5 MWh × *RT LMP*	

The first row shows the resource's credits (revenue) for its day-ahead market awards. In the second row, the resource's day-ahead energy position is closed-out at the real-time price, as illustrated above in settlement examples (a) thru (h). The last row shows the resource's credits for the energy actually it supplies in real-time, in this case, 5 MWh.

► **Implications.** This multi-product settlement method is commonly employed in commodity markets where participants transact both forwards and options for the same delivery time. As such, it is not a new or novel multi-settlement design by any means. In the context of a day-ahead E&AS market, though, it has two properties worth noting here.

First, the ISO's existing day-ahead energy market settlement logic, based on real-time energy deviations, can be thought of as the special case (under the Energy Security Improvements) in which the day-ahead ancillary service quantity is 0 MWh. In that special case, by setting the day-ahead ancillary award quantity (and its closed-out quantity) to 0 MWh and summing the table's five entries, we obtain

$$2\text{ MWh} \times \mathit{DA\ LMP} + [(5\text{ MWh} - 2\text{ MWh}) \times \mathit{RT\ LMP}]$$

which is the familiar two-settlement deviation logic for energy used today. The first term is the day-ahead payment for energy at the day-ahead LMP; the second term (in square brackets) is the real-time payment for "real-time deviations from day-ahead" at the real-time LMP. In other words, this much is the same settlement of day-ahead forward energy positions in use today.

Second, this multi-settlement method avoids the need for a market participant, or the ISO, to assign or allocate a resource's real-time energy production to the resource's distinct day-ahead forward energy obligation and ancillary service obligations. Such assignments would be economically meaningless, and are unnecessary. Instead, each product's day-ahead position is separately closed out in the appropriate way without using the real-time MWh at all (*see* the second row in the table above); the resource then is credited for whatever it provides in real-time.

► **Example with a real-time reserve designation.** This next simple example shows that this multi-settlement method handles real-time reserve designations and payments (credits) for reserves gracefully.

j) Suppose that the resource in case (i) above has the same day-ahead awards as in that example. Now let's assume that it provides 5 MWh of energy in real time and, in addition, it also provides 6 MWh of real-time reserve.

   In this case, its total settlements would be the sum of the five entries in the table shown below. The only change from case (i) above is the addition of the real-time reserve credit in the last row (noted in red text for emphasis in this table).[51]

[51] We simplify here in assuming only one real-time reserve product. In practice, a resource providing real-time operating reserves would receive credit for the quantities of TMOR, TMSR, and TMNSR it provides at their respective prices.

	Forward Sale of Energy	Option Sale of Ancillary Service
Day Ahead Awards (credits)	2 MWh × *DA LMP*	1 MWh × *DA RCP*
Close-out of Day-Ahead Positions (debits)	−2 MWh x *RT LMP*	−1 MWh × max{0, *RT LMP* – *K*}
Real-Time Supply (credits)	5 MWh × *RT LMP* + 6 MWh × *RT RCP*	

Importantly, all of this works smoothly if day-ahead generation contingency reserve (that is, day-ahead TMSR, TMNSR, and TMOR) awards are settled as call options on energy, and then designated and priced in real-time based on the co-optimized real-time market in use today.

We note again here that the real-time dispatch (and the economic evaluation of any additional generation commitments after the day-ahead market, if needed) will continue to be based on resources' energy supply offers in effect during the operating day. Resources would continue to be able to re-offer if, for example, their fuel costs change during the operating day, consistent with existing market rules and procedures. And like today, day-ahead energy and ancillary services awards do not enter into the real-time dispatch calculations. In this way, the real-time dispatch of energy and reserves will continue to reflect the least-cost dispatch of the system.

► **Incentives and implications.** As noted at the start of Section 4.1, the day-ahead ancillary service products are real options on energy: settlements depends on what the associated physical resource produces in real time. Real options strengthen suppliers' incentives to invest in energy supply (or any other) arrangements that will enable them to more reliably produce on short notice, so that they can "cover the call" – that is, produce energy during the operating day if instructed to do so. In that way, the resource owner that acquires a day-ahead ancillary service obligation is able to avoid incurring the potentially steep financial consequence of buying out its call option position if the real-time price is high and it cannot perform (*e.g.,* case (h) in Section 4.3.1).

These investments have a cost, of course, and sellers of these ancillary services need to be appropriately compensated for the obligations and risks they voluntarily assume. For this reason, it is essential that the day-ahead ancillary services be biddable products. The benefit of a co-optimized day-ahead market for energy and ancillary services is that it can find the lowest clearing prices at which all awarded sellers are willing to accept their assigned obligations, and compensate them competitively for doing so.

► **Technical Notes: Option Settlement Location.** The new day-ahead ancillary services introduced by the Energy Security Improvements are system-wide products, procured to satisfy system-level reserve requirements.[52] Like the ISO's (real-time) system-wide reserve products today, each new day-ahead ancillary service product's clearing price will be uniform system-wide (*i.e.,* not zonal or locational).

[52] The specific system-wide requirements are described further in Sections 6.4.1 and 7.2.1.

For the purpose of the energy options' second settlement, this raises the issue of *which* real-time energy price should be used in the energy option close-out of day-ahead ancillary service awards. In real-time, there are both system-level energy prices and nodal energy prices.

For the energy option design, the ISO will settle all day-ahead energy call options at a system-wide real-time energy price – specifically, the Real-Time Hub Price for energy. That price is an average of the real-time LMPs for a pre-existing, stable set of (generally unconstrained) pricing nodes in the ISO's control area.[53]

The reasons that energy call option awards will be settled (that is, closed-out) using a system-wide real-time energy price is that, foundationally, these are system-level products, with uniform system-wide clearing prices, and not locational products with locational prices. If, in the alternative, the close-out charges used the nodal LMPs where resources are individually located, then their day-ahead energy call option offers would not be true substitutes in the market clearing process. That is, in that alternative, sellers that would be paid the same, uniform day-ahead clearing price for the same *nominal* system-wide product, but would in fact face different settlement rates (close-out charges) for identical performance – yet offers were cleared to meet the same system-wide demand for reserves.

Since the close-out settlement will be based on the real-time Hub energy price, the *RT LMP* notation in examples (i) and (j) above should be interpreted accordingly. That is, this settlement treatment means the RT LMP used in the option close-out step (*see* the *second* row, right column, of each table in examples (i) and (j)) is the *Hub* RT LMP. That value may differ from the actual *nodal* RT LMP applicable to a resource's settlement of (*i.e.,* credit for) its real-time energy produced (as shown in the *third* row of each table in examples (i) and (j)). These locational energy differences may arise due to congestion and marginal loss pricing in the real-time market, when congestion arises or losses differ in real-time between the Hub component locations and the day-ahead ancillary service seller's resource's location.

After reviewing these considerations with stakeholders during the past year, we have determined that using the real-time Hub Price for all energy call option settlements of the new day-ahead ancillary services preserves the uniform, system-wide nature of these products. Importantly, New England has a relatively uncongested transmission system, and as a result we do not expect this design element to prove particularly consequential, as a practical matter.

4.4 Sellers' Obligations

During the stakeholder review process for the Energy Security Improvements, the ISO stressed that a seller of day-ahead ancillary services has a "no excuses" settlement obligation. That settlement obligation uses the multi-settlement design for a call option on real-time energy, as discussed above. Importantly, and by design, those settlement charges reflect the system's incremental cost

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[53] *See* Tariff Section III.2.8.

to replace any real-time energy that a day-ahead ancillary service seller does not provide (*see* again case (h) in Section 4.3.1).

Several market participants inquired as to whether additional obligations are imposed upon a seller that receives a day-ahead ancillary service award. This question is sometimes framed in terms of whether the obligations, and the day-ahead ancillary service market more generally, is "physical" or "financial." In more precise terms, the salient questions are whether, under the new design, a seller with a day-ahead ancillary service award is obligated to arrange fuel (at any available price) for its resource, and whether it is a violation of the market rules if it has no fuel to operate in real-time.

In brief, if a seller that has no market power receives a day-ahead ancillary service award, and subsequently does not provide energy during the corresponding real-time award hour, the seller will be subject *only* to the market's settlements as specified in the revised market rules. Specifically, it will be charged based on the price of real-time energy (if that price exceeds the applicable hour's strike price).[54] In a well-designed market, that is the economically correct remedy when the seller of an energy call option does not provide real-time energy.

We do not stipulate additional obligations, in the form (say) of an obligation to acquire fuel at any available price or an obligation to demonstrate the physical unavailability to procure fuel. As we explain presently, such additional obligations should be expected to result in excessive fuel procurement expenditures, impede generators' willingness to participate in the market, and ultimately result in unnecessarily high consumer costs.[55]

► **Clarifying terminology.** The new day-ahead ancillary services market is a physical-delivery market. A market participant offering to sell day-ahead ancillary services must offer the physical capability of an identified resource when it submits its energy option offer. Moreover, with co-optimized day-ahead energy and ancillary services, the clearing of ancillary service awards is expressly based on the ramping capability and other physical parameters of that resource. In this regard, the day-ahead ancillary services market is intended to enable resources to physically deliver real-time energy commensurate with their awards (*i.e.*, in amounts and with lead-times corresponding to each resource's capabilities and its day-ahead energy schedule).

Like physical-delivery markets generally, the day-ahead ancillary services market has financial consequences for non-performance. The consequence of non-performance, given a day-ahead ancillary service award, is a net settlement charge based upon the price of real-time energy (as described in Section 4.3.1). Under the revised market rules, this market settlement charge is the consequence if a seller of a day-ahead ancillary service does not provide energy with its associated physical resource in real-time.

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[54] *See* new Tariff Section III.3.2.1(q)(2) *et seq.*

[55] As a separate point, this should not be construed as a limitation on appropriate remedies for (or deterrents to) physical withholding by a supplier with market power. A supplier that physically withholds its capability (*ipso facto*) does *not* acquire an ancillary service award; in contrast, we focus here on the obligations of a supplier that *does* acquire a day-ahead ancillary service award. Consequently, physical withholding involves different (opposite) circumstances than when a supplier acquires an ancillary service award, as discussed herein.

From a terminological standpoint, referring to day-ahead ancillary services as a physical-delivery market does not imply that day-ahead ancillary service sellers have an obligation to acquire fuel for their resource at any price (sometimes referred to as a "specific performance" obligation). A well-designed market for the physical delivery of a tangible service should be clear about the consequences for non-performance, but by no means do such consequences need to entail a specific performance obligation.

4.4.1 Layering extraneous obligations over a well-designed market is inefficient

In a well-designed market, sellers are not induced to incur costs that are greater than the benefits those expenditures bring to the system. If a day-ahead ancillary service seller is obligated to procure fuel at any available price, for instance, then the seller may incur costs that exceed the system's cost to obtain energy from an alternative resource. In aggregate, such an obligation would result in inefficiently high costs to sellers, causing higher ancillary service offer prices, reduced market participation, or both. Either would produce inefficient outcomes and unnecessarily high consumer costs.

Under the Energy Security Improvements design, a more cost-effective outcome is achieved by aligning the seller's private incentives to incur fuel-related costs with the expected replacement cost of (electricity) energy in real-time. This alignment is achieved with a simple mechanism: if a seller of a service is unable to perform (for any reason), the market will rely on the least-costly alternative resource available in real-time to replace the energy from the non-performing resource, and charge the non-performing resource's owner for the additional cost of that replacement energy. (*See* Sections 5.1.2 and 5.3.2, which explain in detail how energy options align the costs of arranging fuel supplies with the expected benefit to the system, producing cost-effective outcomes).

► **Replacement cost and real-time scarcity prices.** It is important to note that covering the real-time replacement cost is the appropriate obligation of a non-performing seller not only during normal market conditions, but also during stressed system conditions when reliability is at heightened risk. During a real-time shortage of operating reserves (or, in extreme situations, of energy), the real-time energy price that a non-performing seller is charged incorporates the system's real-time reserve shortage price(s).[56] In this way, the "replacement cost" that a non-performing day-ahead ancillary service seller is charged will not only reflect the actual cost of energy from the marginal resource, it will additionally include the (maximum) price that the system is willing to incur to reduce (and to avoid) the real-time shortage – whenever that shortage is made worse by the seller's non-performance.

Because the replacement cost charged to a non-performing seller will incorporate the "scarcity" cost of a shortage of reserves (or of energy) whenever it occurs, the seller's incentive to procure fuel is aligned with the cost the system ascribes to the shortage. That point is crucial to how the Energy Security Improvements design provides sellers with the appropriate fuel procurement incentives. Real-time

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[56] This occurs to the extent an incremental MWh of energy from the seller would reduce the real-time reserve shortage. The system's reserve shortage prices are known as Reserve Constraint Penalty Factor values in the Tariff.

reserve shortage pricing is the pre-existing, Commission-approved mechanism for ensuring that the market properly signals the value of a shortage—or, stated more precisely, the value of the benefit obtained by *avoiding* the shortage. Charging a non-performing seller for the replacement cost, including this scarcity cost, when the seller's non-performance contributes to a reserve (or energy) shortage broadcasts to the seller the (maximum) cost it should incur—no more and no less—to arrange fuel in order to provide energy.

In simple terms, this mechanism—and the energy call option's market settlement rules under the new design—aligns the seller's incentives to perform with the value that the region places on avoiding a shortage, as reflected in the system's real-time reserve shortage pricing mechanism. This alignment produces cost-effective incentives for a day-ahead ancillary service seller to perform generally, and to procure fuel specifically.

► **Implications.** It should be apparent that to achieve these objectives in an economically-sound manner, the Tariff must not layer onto the market any additional obligation that forces sellers to base their fuel procurement decisions on factors *other than* the replacement cost of real-time energy (inclusive of its scarcity cost, when that occurs). Doing so not only increases sellers' fuel procurement expenditures excessively – the extra-market obligations may increase sellers' regulatory uncertainty (over a potential Tariff violation of such extra-market rules).

Sellers can reasonably be expected to reflect such extra-market costs and risks in their option offer prices for day-ahead ancillary services, thereby increasing the overall costs that consumers ultimately pay. Further, should the regulatory risk prove significant, it may undermine some sellers' willingness to participate in the day-ahead ancillary services market altogether. In this case, fuel-related obligations beyond the proper market settlements would produce an adverse "double-whammy" of inefficiently high offer prices (reflecting excessive fuel procurement expenditures) and reduced market participation by competing suppliers (due to regulatory uncertainty). Taken together, these foreseeable consequences would undermine the cost-effectiveness of the new day-ahead ancillary services design and unnecessarily raise costs to consumers.

In summary, to impose performance obligations that induce a seller to devote financial resources *beyond* the amount that it would spend facing only economically-correct market consequences for non-performance—*i.e.,* facing only market settlements based on real-time replacement cost—would be both to consumers' detriment, and inconsistent with the ISO's obligation to create and sustain economically efficient markets.[57]

4.5 Energy Option Strike Prices

A strike price is a new concept in the ISO's energy and ancillary service markets. As we explain presently, this is an important design concept because the strike price affects day-ahead ancillary service sellers' incentives to invest in energy supply (*i.e.,* fuel) arrangements.

[57] *See* Tariff Section I.1.3(b).

Fortunately, options are familiar enough in other contexts that their economic analysis provides considerable guidance. In this section, we first describe several guidelines that govern how energy option strike prices will be determined for the day-ahead ancillary services market. We then summarize various practical design elements, and their associated provisions in the revised market rules.

As a general matter, there are three important aspects that guide how strike prices should be determined in a day-ahead E&AS market design. The:

1. **Known before offers due**. The numerical value of the strike price must be known to participants in advance of when they must submit energy and ancillary service offers in the day-ahead market.

2. **At the money.** The most efficient outcomes are obtained when the strike price is set at approximately the expected value of the energy price at which the options will settle.

3. **Accurate, within limits.** In practice, small inaccuracies in setting the strike price precisely 'at the money' should not matter much.

We explain each of these guidelines, and discuss their practical ramifications for the day-ahead ancillary services market, next.

4.5.1 Strike Price Guidelines

► **Guideline 1: Known before offers due.** The first guideline requires that the market rules provide a strike price that will be fixed (or "locked down") in its numerical value prior to the offer submission window for the day-ahead market. If the strike price (*K*) is not fixed before offers are due, then suppliers would have no way, in advance of submitting their offers, to anticipate how much risk they will be exposed to for a given outcome of the real-time price.

Put differently, the settlement of an energy call option – and the (minimum) price a resource owner would be willing to offer to take on a day-ahead ancillary service obligation – depends explicitly on the (numerical) value of the strike price, *K.* This dependence can be seen in the multi-settlement table entries shown in Section 4.3.2 above (*see* examples (i) and (j), where the close-out of day-ahead positions formula includes the strike price *K*). If resource owners do not know the value of the strike price prior to when day-ahead offers are due, they would have no obvious way to formulate a competitive offer price for the day-ahead ancillary services.

► **Guideline 2: At the money.** The second guideline specifies that to provide efficient incentives for arranging energy supplies (at the margin), the strike price can be set at the expected value of the real-time LMP for the corresponding delivery hour. The term of art that goes with this guideline is setting the strike price "at the money." A strike price that is set materially higher than that will tend to mute incentives to invest in energy supply (*i.e.,* fuel) arrangements, undermining the performance of the day-ahead E&AS design.

The idea behind this guideline is simple. Consider the extreme case where the strike price is set very high – higher than the highest possible value of the real-time LMP. In this case, in the option's settlement, the value of the close-out of the day-ahead award would always be zero. That is, if the strike is so high that K > RT LMP in all situations, then the value of the close-out term, *max*{0, *RT LMP* – *K*}, is always zero (because *RT LMP* – *K* would always be less than zero). And if that were the case, the competitive clearing price of day-ahead ancillary services would also be zero, as there would never be any charge applied when resources with day-ahead ancillary service obligations fail to perform.

Ironically, the situation just described is effectively the same, from an incentive and compensation standpoint, as the energy-only day-ahead market construct we have today for resources without day-ahead energy market awards. If the option strike price is set too high, then suppliers with a day-ahead ancillary service obligation face no risk of having to incur the cost of "replacing their MWh" in real-time settlement if they do not perform; their only settlement would be a real-time credit for what they supply in real time. That's the same as what the current market design provides for the resources that are not scheduled in today's day-ahead market. Put simply, if the strike price is set too high, then incentives for suppliers to invest in arranging energy supplies in advance would not be changed from today's market design at all. A high strike price does not solve the misaligned incentives problem.

If a too-high strike price would undermine day-ahead ancillary service providers' incentives, at what strike price level would it not? Here, economics provides a sharp answer. In general, an energy option award will provide a resource with efficient incentives to cover its award (*e.g.,* to arrange fuel) if the strike price is set at, or below, the resource's marginal cost of producing energy.

To see why, consider the opposite, where the strike price is greater than a resource's marginal cost of producing energy. In that situation, there will be a range of real-time energy prices (namely, prices above its marginal cost and below the strike price) for which it would be economic for the resource to operate – *if* it has arranged fuel – but for which the resource will face no option close-out charge if it has not. And the higher the strike price is above the resource's marginal cost, the greater the potential that the resource will be in demand to serve real-time energy but face no financial consequences if it does not. Such situations would plainly undermine the resource's incentives to arrange energy supplies, even when such arrangements are beneficial (*i.e.,* cost-effective and reliability-enhancing) from society's standpoint.

Put simply, to avoid diluting a resource's incentives for cost-effective energy supply arrangements, the strike should be set at or below the seller's marginal cost of energy in real-time.[58] In application, however, that economic principle raises another issue. As a purely theoretical matter, that principle would be achieved by setting hourly, resource-specific strike prices based on each individual resource's marginal costs of energy. Such a "customized," non-uniform strike price approach would

[58] Although not obvious, a resource's incentives do not strengthen further by setting a strike price below, rather than at, its marginal cost. For example, there is no additional efficiency gain from setting a strike price at zero, rather than at a resource's marginal energy cost. We explain this in greater detail below (*see* Section 5.3).

be impractical, however, and poses other undesirable consequences.[59] Fortunately, the market provides a practical alternative that is consistent with providing economically-sound incentives.

Specifically, the desired incentives can be reasonably achieved by setting the strike price – uniformly for all resources – at the expected value of the real-time energy price (for the corresponding delivery hour). The logic here is simple. In the real-time markets, resources that have *lower* marginal costs than the real-time energy price are committed and dispatched to supply energy. Resources, or portions thereof, that have *higher* marginal costs than the real-time energy price are designated by the dispatch to supply reserves (provided they have the requisite response and ramping capabilities).[60]

Therefore, setting the strike price at the expected value of each hour's real-time energy price will serve the objective of providing a transparent, uniform strike price at or below ancillary service resources' marginal costs. By doing so, the strike price should not undermine ancillary service sellers' incentives; rather, the energy option design will maximize their incentives to make all cost-effective energy supply arrangements to ensure their resources can perform when needed.

► **Guideline 3: Accurate, within limits.** In practice, setting a strike price at the expected value of the real-time LMP for the delivery hour requires an estimate, or forecast, of the expected real-time LMP. That estimate must be provided to all participants prior to submitting bids and offers into the day-ahead market (per Guideline 1). Fortunately, small inaccuracies in setting the strike price 'at the money' should not matter much.

Forward looking forecasts of market outcomes are inherently imperfect, even if, on average, they are neither too high nor two low. The structure of resources' incentives under the energy option design suggests such inaccuracies will not tend undermine the design's performance, at least within limits. If the strike price is set too low, more resources with day-ahead ancillary service awards may have a strike price below their marginal costs; that provides no additional benefit, and may raise their option offer prices, but it does not undermine their incentives to cover their day-ahead obligations.

In the opposite direction, if the strike price is set too high – *i.e.,* higher than some ancillary service sellers' marginal costs – that may begin to reduce some sellers' incentives below what would be efficient. However, even then, those incentives may not drop abruptly (*i.e.,* not discontinuously) if the strike price exceeds a resource's marginal energy cost. We explain these technical points further, using a numerical example, in Section 5.3 below.

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[59] In particular, resource-specific strike prices would result in different close-out settlement costs for sellers with identical performance under identical market conditions. That runs contrary to a more fundamental principle of equal compensation for equal service. In addition, resource-specific strike prices makes a proper economic comparison of option offers (*i.e*., their substitutability) in the market-clearing process very difficult.

[60] There are exceptions, such as when real-time re-dispatch is needed to create reserves on a resource with a marginal energy cost below the real-time LMP. From a design standpoint, these situations argue for setting the strike price low, not for setting a strike price high, relative to the expected real-time LMP.

The bottom line is that, in theory, small inaccuracies in setting the strike price "at the money" should not impact incentives much. And, in developing practical implementations of theoretically-sound improvements to the region's market design, we are cognizant of the need to not let the perfect become the enemy of the good.

4.5.2 Strike Price Specifics and Practicalities

In this section, we summarize various practical aspects of the strike price calculation, and the corresponding supporting provisions of the revised Tariff.

► **A dynamic calculation.** As noted previously, the strike price will be based on the expected real-time price of energy. Expected real-time energy prices vary from hour-to-hour, and from day-to-day. This is because expectations of real-time prices depend on such factors as expected energy demand, weather forecasts, gas price forecasts, the hour of the day, day of week, season, and other factors. Accordingly, the strike price will vary each hour of the day; that is, there will be 24 different strike prices, one for each hour of the applicable operating day. The strike prices will be calculated and posted prior to each day's submission deadline for the day-ahead market.

Since strike prices are posted prior to the day-ahead market, the strike prices will be based on a forecast of the hourly expected real-time energy price for the (applicable) operating day. We anticipate the forecast will be a function of information including (but not limited to) the latest weather forecasts, gas prices, hour of the day and day of the week, seasons, and other data that are statistically useful for forecasting hourly real-time energy prices.

► **Context: Current practice.** Fortunately, the ISO has considerable experience developing and implementing short-term (hourly and multi-day) forecasts of gas and electricity prices. For market administration and market monitoring purposes, the ISO has developed and uses both internally-developed price forecasting tools (based on publicly-available data), and price forecasting services from specialized commercial vendors.[61]

As a practical matter, the ISO reviews and shares the methodology for internally-developed price forecasts, and publicly provides to stakeholders assessments of their performance in comparison to commercial vendors' price forecasts.[62] The underlying "state of the art" in machine-learning algorithms for these purposes continues to improve, so the ISO periodically reviews and updates its

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[61] For example, the ISO presently uses price forecasts to calculate intertemporal opportunity costs for more than 100 individual oil- and dual-fuel generators (performed daily for the next 144 hours). *See* Energy Market Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated September 13, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/09/a10_memo_re_energy_market_opportunity_costs_for_oil_and_dual_fuel_resources_with_inter_temporal_production_limitations.docx.

[62] *See*, e.g., Natural Gas Price Forecast Method for Energy Market Opportunity Costs, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated October 9, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_natural_gas_forecast_method_energy_market_opportunity_costs.pdf.

price forecasting methods and sources. When circumstances warrant improvements to the price forecasting process, tools, or sources, the ISO provides stakeholders with information and rationales for changes prior to changing the algorithms or commercial vendor service used in production.[63]

► **Process for strike prices.** Based upon extensive stakeholder discussions and feedback during 2019 and 2020, the ISO will use a broadly similar approach (to that described above) for the dynamic calculation of hourly strike prices. Forecasting the expected real-time energy price, in advance of the day-ahead market, for the purpose of calculating hourly strike prices, is a new application of similar price forecasting tools and systems.

As noted in Section 4.3, all energy call options are to be settled using the Real-Time Hub Price for energy. We expect the ISO's forecast process will directly estimate the expected Real-Time Hub Price, rather than the myriad real-time nodal prices that comprise the real-time Hub Price for energy.

For strike price calculation purposes, this process is to be governed by a new Section III.1.8.3 of the Market Rules in the Tariff, which has the following substantive provisions:

- Consistent with Guideline 1, the (numerical value of) the Energy Call Option Strike Price for each hour of the Operating Day will be publicly posted in advance of when bids and offers are due in the day-ahead market.
- Consistent with Guidelines 2 and 3, the Energy Call Option Strike Prices, in $/MWh, will be a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day.
- To facilitate transparency, the forecast used to determine the Energy Call Option Strike Prices shall be based on a publicly-available forecasting algorithm. That may be an ISO-developed forecasting algorithm, a published (*e.g.* academically-developed) methodology, or other source consistent with this requirement, as proves suitable after development, evaluation, and review.
- Consistent with existing practice, the ISO will review any potential revisions to the forecasting process and algorithms, prospectively, through the stakeholder process.

The last point highlights an important practical observation. Technologies and algorithms applicable to short-term (hourly and multi-day) price forecasting, particularly those employing newer machine-learning and neural-network-based technologies, are steadily improving over time. Accordingly, the ISO anticipates periodically reviewing, and if warranted, developing technical improvements to the price forecasting process or source(s) as better algorithms become available. The provisions in this new Section III.1.8.3 are designed to enable the ISO to develop and implement such technical

[63] *See*, e.g., Energy Market Opportunity Cost Changes Taking Effect on December 3, 2019, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated November 6, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/11/a7_a_memo_re_energy_market_opportunity_cost_changes.pdf.

process improvements, while providing transparency and the opportunity for stakeholder review and feedback, to the strike price calculation methodology.

4.6 Energy Option Offer Particulars

In this section, we note various rules governing energy option offers and their associated new Tariff provisions in this filing.

► **Context.** As noted at the outset of Section 4.2, the day-ahead ancillary services uses a 'one offer, multiple products' market clearing design. Participants may submit a single energy call option offer for a particular hour, not offers specific to each type of ancillary service. Stated differently, participants' energy call option offers are the *inputs* into the day-ahead market clearing process. Day-ahead obligations for each ancillary service type – Energy Imbalance Reserve, Generation Contingency Reserve, and Replacement Energy Reserve – are the *outputs* of the market-clearing process. The co-optimized day-ahead market clearing engine will determine the most cost-effective assignment of the offered energy option to meet each of the system's day-ahead ancillary service requirements.

Consistent with this 'one offer, multiple products' market clearing design and the 'at the money' principle for setting the strike price, each cleared energy option offer for a particular hour will be settled using the same strike price (namely, the system's applicable strike price for that hour of the operating day). That is, the strike price is does not vary for the different types of ancillary services awarded in a particular hour.

► **Offer particulars.** Each energy call option must be associated with a specific resource. As noted in Section 4.2, and discussed further in Section 7, the market clearing process is expressly based on resources' physical operating characteristics (ramp rates, startup lead times, maximum output levels, and the such). This will ensure that awards for each ancillary service product do not exceed the resource's capability to deliver (*e.g.* awards of GCR Ten Minute Spinning Reserve do not exceed a scheduled-to-be-online resource's upward ramping capability over ten minutes, and so forth). A resource associated with an energy call option offer must have an energy supply offer for the same hour, so the co-optimized market clearing process can account for the resource's energy schedule and its physical operating limits and capabilities (which are formally part of its energy supply offer).

Formally, under the Energy Security Improvements, an energy call option offer will comprise an offer price, an offer quantity, and the applicable hour of the next (operating) day. Offered prices and quantities may vary by hour, as is currently allowed for energy supply offers and energy demand bids offers in the day-ahead market.

An energy call option offer's price and quantity must satisfy certain limits. These are based on economic or physical considerations. Offer quantities may not be negative numbers, nor exceed the associated resource's maximum energy output (known as its "Economic Maximum" output in the existing Tarff). Offer prices may not be negative, as a negative price is not economically logical when selling a call option (the option close-out settlement always imposes a non-negative settlement cost on the participant). The tariff places a non-substantive restriction on the maximum option offer price, based on the highest Reserve Constraint Penalty Factor applicable to the new requirements. This restriction is non-substantive in that any energy call option offer submitted at an offer price higher than that value would be pointless, as it would never clear in the day-ahead market.[64]

For a particular resource, an energy call option offer may have only a single offer price; that is, energy call options may not be offered with multiple price, quantity pairs. This limitation is necessitated by technical constraints; allowing multiple segments for both a resource's energy supply offer and its energy call option could create a non-convex objective function in the market clearing engine that would be difficult (if not impossible) to co-optimize.

► **Corresponding new tariff provisions.** Consistent with the foregoing discussion of offer requirements, new Section III.1.8.2 of the Market Rules succinctly describes the Energy Call Option Offers provisions. Specifically:

- Section III.1.8.2(a) provides that an Energy Call Option much be associated with a physical resource with a concurrent energy supply offer (or, for a demand response resource, a demand reduction offer) for the same hour.

- Section III.1.8.2(b) stipulates that the Energy Call Option Offer shall specify a price, quantity, and applicable hour of the next (operating) day, and those offered values must satisfy the numerical limits described above.

- Section III.1.8.2(c) imposes the limitation of only one offer price per resource discussed above (that is, no multiple offers or multi-segment offers are permissible for Energy Call Option offers).

- Section III.1.8.2(d) addresses administrative timing and submission requirements for the day-ahead market process.

[64] *See* Section 6.4.3 (explaining that Reserve Constraint Penalty Factors limit the cost the system will incur to satisfy a reserve requirement).

5. How Energy Options Solve Misaligned Incentives

We now return to central objectives of the day-ahead ancillary service products. We will explore how these day-ahead ancillary services products change resource owners' incentives to take real actions – to incur the up-front costs of arranging energy supplies in advance of the operating day, even when that energy may not be used.

For this purpose, we revisit the prior numerical examples from Section 2 to show how this design helps solve the misaligned incentive problem (Problem 1 as described in Section 2.2) associated with today's energy-only day-ahead market construct.

Importantly, the analysis and implications provided in this section apply equally to all of the new, day-ahead ancillary service products – whether energy imbalance reserve, generation contingency reserve, or replacement energy reserve. The common incentive and efficiency properties we show next are a result of the energy call option structure of the design, and its replacement-cost settlement logic. In subsequent Sections 6 and 7, we will address pricing, clearing, and other design features that are specific to each of the three new day-ahead ancillary service products.

5.1 Example 1, Revisited: A Cost-Effective Market Solution

In this section, we show that introducing a call option on energy strengthens a resource owner's incentive to invest in energy supply arrangements that benefit the system overall. Our immediate purpose is to explain how – and why – the addition of day-ahead ancillary services, when settled as call options on real-time energy, should solve the misaligned incentive problem discussed in Section 2.

At the outset, it is useful to note that in creating a market product to solve the misalignment problem, the market must achieve two distinct, but interrelated, goals. First, it must compensate the supplier sufficiently that it will be willing to incur the (up-front) costs of arranging energy supplies, whenever that would be cost-effective from the system's standpoint. Second, that compensation cannot simply be a handout. There needs to be a well-designed financial consequence tied to whether or not the resource provides energy, so that it will be induced to follow through and undertake arrangements that benefit the system. In revisiting Example 1 next, we show how the new energy options approach achieves both of these key goals.

► **Example 1: A recap.** In Example 1 from Section 2.2.1, a 1 MW generator, without a day-ahead market position, faces an unlikely possibility that demand may be high enough for it to operate the next day. It must decide in advance whether or not to incur the cost of arranging fuel. It knows there is only a 20% chance that its resource will be dispatched (if available) the next day, so the advance fuel arrangement will, in all likelihood, not be used. The main assumptions, from Table 2-1, are reproduced below for convenience.

Table 2-1. Cost and Price Assumptions for Example 1					
	With Advance Fuel			No Advance Fuel	
	High Demand	Low Demand		High Demand	Low Demand
Up-Front Cost of Advance Fuel	$ 40	$ 40		$ -	$ -
Marginal Cost	$ 70	n/a		n/a	n/a
Energy Price (LMP)	$ 120	$ 60		$ 400	$ 60
Demand Probability	20%	80%		20%	80%

In analyzing Example 1, the key results we obtained (*see* Section 2.2.1) were:

- The expected net benefit to the system of arranging fuel (*i.e.,* expected cost savings) is 20% × ($400 – $70) = $66 by avoiding running the expensive $400 generator if demand is high, minus the $40 up-front cost of arranging fuel, for a net benefit to society of **$26.** The most cost-effective – *i.e.*, efficient – outcome for the system would be achieved if the generator makes the arrangements for fuel in advance of the operating day.

- The expected net benefit to the generator of arranging fuel in advance comes from an expected gross margin of 20% × ($120 – $70) = $10 by being able to operate if demand is high, but this is not enough to cover the $40 up-front cost of arranging fuel. The generator's expected profit is therefore a net loss, **–$30**. In other words, arranging fuel in advance is not financially prudent for the generation owner.

The main point of Example 1 was that the energy market, in its *current* form, does not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. This is a 'market failure' to incent efficient outcomes, causing higher expected costs to society as a result.

The logic underlying this conclusion is important. As explained in Section 2, the value that society places on the fuel arrangement is based on the high price it *avoids* as a result of the investment (*i.e.,* the $400 real-time LMP in Table 2-1). However, the value the generator places on the same arrangement is based on the lower price it *receives* in the energy market with the investment (*i.e.,* the $120 real-time LMP in Table 2-1). This value difference is the heart of the misaligned incentives problem: a divergence between the social and private benefit of the investment.

5.1.1 Example 1 with a Day-Ahead Ancillary Service Award

Now let's examine how the outcomes change if the generator in Example 1 has an ancillary service award, settled as a call option on energy under the Energy Security Improvements. Our point is to illustrate that such a product serves to align the incentives properly: the generator will find it in its private interest to arrange fuel in advance of the operating day, when that action is cost-effective from the system's standpoint.

In the discussion next, we do not specify whether the specific day-ahead ancillary service product here is for energy imbalance reserve, generation contingency reserve, or replacement energy reserve; the discussion is equally applicable to any of those products.

We now extend Example 1 to include the new day-ahead ancillary service products, making the following assumptions about the prices of those products:

- The option price ("*V*," in the nomenclature of Section 4) – that is, the day-ahead clearing price for reserve – is $50/MWh.

- Assume the strike price ("K," in the nomenclature of Section 4) is $120/MWh.

The first assumption will be sufficient for this generator to be willing to accept the day-ahead ancillary services obligation, given the strike price. This will be apparent after a few initial calculations, provided below.

The strike price for this example matches the real-time LMP in the high demand scenario, when the generator has arranged fuel. For the moment, this particular strike price is an assumption of convenience (to simplify calculations). The conclusions of this example would be unchanged if the strike price was lower than $120/MWh, but not if it was higher; we explain why in Section 5.3 subsequently.

Table 5-1 shows the generator's expected net revenue, for the case where it arranges fuel and the case when it does not. In row [1], we show that the generator receives the $50 day-ahead clearing price (the option price) for its 1 MWh day-ahead ancillary service award. If real-time demand turns out to be high, the generator is paid the real-time LMP of $120/MWh, and incurs its cost to arrange fuel of $40 and marginal cost of $70, for a scenario net revenue of $60/MWh in row [8] ($170 minus $110). If demand is low and it has arranged fuel, it does not operate. In that case, the $50 day-ahead price for reserve covers its $40 cost of arranging fuel, for a scenario net revenue of $10 in row [8]. Its expected net revenue, if it arranges fuel, is therefore $20 (as shown in the bottom-left cell in row [10]). Arranging fuel is now a profitable endeavor, even though there is an 80% chance the arrangement would not be used.

Table 5-1. Generator Expected Net Revenue for Example 1, With Option Award						
			Advance Fuel		No Advance Fuel	
Generator's Market Settlement			High Demand	Low Demand	High Demand	Low Demand
[1]	Day-Ahead Award	*DA RCP*	$ 50	$ 50	$ 50	$ 50
[2]	Day-Ahead Close-Out	-max{0, *RT LMP* - *K* }	$ -	$ -	$ (280)	$ -
[3]	Real-Time	*RT LMP*	$ 120	$ -	$ -	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 170	$ 50	$ (230)	$ 50
Generator's Costs						
[5]	Advance Fuel	*F*	$ (40)	$ (40)	$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -	$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)	$ -	$ -
Generator's Net Revenue						
[8]	Scenario Net Revenue	[4]+[7]	$ 60	$ 10	$ (230)	$ 50
[9]	Demand Probability	*p* or (1-*p*)	20%	80%	20%	80%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**$20**		**($6)**	

Now consider the generator's revenue if it did not arrange fuel in advance. It again receives the $50 day-ahead price for its day-ahead ancillary service award in row [1]. If demand is low, it does not run and incurs no costs, for a scenario net revenue of $50 (as shown in the last column of row [8]). If demand is high, however, it would not be able to operate without fuel arrangements. In this scenario, its cost to settle (or 'buy out') of its day-ahead ancillary service position in real-time settlements, given the high $400 real-time LMP, is

$$\max\{0, RT\ LMP - K\} = \max\{0, \$400 - \$120\} = \$280.$$

This is shown as a negative value in row [2] because it is a cost to the generator. Its net revenue in this scenario is $50 – $280 = – $230, a net loss, as shown in row [8]. Taking the scenario likelihood-weighted average, its expected net revenue if it does not arrange fuel in advance of the operating day is a net financial loss of $6, shown in row [10].

Of course, we haven't fully "closed the loop" on this generator's decisions yet. Specifically, This example also shows that the generator would be willing to accept the day-ahead option award, given a clearing price of $50, assuming the generator is seeking to maximize its expected profit. As Table 5-1 shows, in row [10], the generator would now find it financially prudent to incur the $40 cost of arranging fuel in advance, a decision that yields an expected net revenue of $20.

In fact, revisiting Table 2-2 in Section 2.2.1 demonstrates that, in this example, an expected profit-maximizing generator would be willing to accept a day-ahead ancillary service award price as low as (just above) $30, as that would yield a greater profit than the $0 net revenue it would obtain under its best alternative without a day-ahead ancillary services award. Indeed, if this was a broader example with many competitors, this generator's (lowest) profitable offer price for the day-ahead reserve obligation would therefore be (just over) $30/MWh.

► **Implication.** The main point here is simple, and important. Real options change behavior – in this case, the generator's willingness to undertake a costly investment in arranging fuel that may not be used. In this example, that willingness arises because the generator's valuation of the investment (the $40 up-front cost to arrange fuel) is no longer based solely on the $120 real-time LMP it receives (at best) when it has fuel. Instead, its valuation of the investment is also based on the $400 real-time LMP that society *avoids* if it makes the investment. Mathematically, this occurs because that $400 real-time LMP enters into the generator's cash flows in row [2], when it is in demand but cannot operate. In that case, as noted above, it incurs a charge in the ancillary service market settlement in the amount of:

1 MWh × max{ 0, $400 *RT LMP* – $120 *strike* } = $280.

Conceptually, the generator is now basing its decision on the same high cost that the system would incur *to replace the generator's output*, even though there is an unlikely (*i.e.,* only 20%) chance that the generator is needed to meet demand.

In this manner, the Energy Security Improvements' option settlement design aligns the generator and society's incentives to focus on the same, high $400 avoided cost. Selling the option leads the generator to internalize, in its financial calculus, the high cost that may prevail if it cannot operate when its generation is in demand.

5.1.2 Energy Options Provide Economically-Appropriate Incentives for Cost-Effective Energy Supply Arrangements

There is a second important implication of this energy option example. We stated earlier (in Section 4.3) that with day-ahead ancillary services that settle as options on energy, it becomes profitable for generators to pay the up-front costs of maintaining reliable fuel arrangements *when such arrangements are cost effective* from the standpoint of the system overall. Let's focus on that cost-effective attribute now. It implies there are limits to the costs the generator would be willing to incur up-front – but those limits align with the limits on what society would find beneficial.

To see why in the context of Example 1, recall that with a $40 up-front cost to arrange fuel in advance, the expected cost savings to the system are $26. That means the *most* society would be willing to incur, from the standpoint of cost-effectiveness, would be a $66 up-front cost to arrange fuel in advance. In that situation, the expected benefits and expected costs would be equal.

Now consider the case if the up-front cost is even higher – let's assume, for the moment, it is $75. In that case, the expected (value of the) benefit to the system of arranging fuel (*i.e.,* expected cost savings) is 20% × ($400 – $70) = $66 by avoiding running the expensive $400 generator if demand is high, minus the now **$75** up-front cost of arranging fuel, for a net benefit to society of $66 – $75 = **–$9**. In this case, from the system's standpoint, the investment in advance fuel arrangements is not cost-effective; it would be more cost-effective just to run the high-cost $400 generator in the unlikely (*i.e.,* 20%) chance that demand is high.

Does this align with the generator's incentives, in a market that provides it with the opportunity for a day-ahead ancillary service award? Yes – the generator would not find the investment cost-effective either, at a now $75 up-front cost. To see this, note that if the up-front cost is now $75, then the entries in row [5] in Table 5-1 would change from negative $40 to negative $75, a difference of $35, and the generator's expected net revenue in the bottom row of Table 5-1 – in the case where it arranges fuel in advance – would drop by $35, to become a net financial *loss* of $15 ($20 – $35 = –$15)**.** Facing that prospect, the generator's prudent financial decision would be to not incur the $75 up-front cost of cost of arranging fuel in advance, in which case its expected net revenue would be zero (*see* Section 2.2.1, Table 2-2, bottom right cell). And, as explained in the previous paragraph, this outcome aligns with society's interests as well.

One can do this same exercise with a range of possible up-front investment costs, with the same pattern of conclusions. The generator would find it financially prudent to invest if the up-front cost of arranging fuel is up to $66, but not any higher.[65] That matches, exactly, the maximum investment that would be cost-effective from society's perspective as well. Again, the reason is simple: the option settlement design is (explicitly) based on the generator internalizing, in its financial calculus, the replacement cost of energy in real-time if the generator is unable to perform.

This conclusion might seem to be an artifact of the particular numbers chosen for Example 1, but that is not the case. The conclusion illustrated here is a general property. Providing generators with the opportunity to compete for day-ahead ancillary service awards that are, in real-time, settled as call options on energy make it financially prudent for a generator seeking to maximize its expected profit to incur the up-front cost of arranging energy supplies in advance – but only when those arrangements would be cost-effective from society's standpoint as well.[66]

5.2 Example 2, Revisited: Day-Ahead Options with Real-Time Reserves

In this section, we revisit the misaligned incentives problem that arose with multiple generators in Example 2 in Section 2.8. As with Example 1, we show that introducing a call option on energy as a day-ahead ancillary service improves resource owners' incentives to invest in energy supply arrangements, to the benefit of the system overall.

The central point of this example is to again illustrate, in a more complex setting with multiple generators and multiple products, how and why introducing day-ahead ancillary services, when settled as call options on real-time energy, provides stronger and more efficient incentives than the

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[65] It may seem initially curious that this generator, with a day-ahead payment of $50, would spend up to $66 to arrange fuel in advance of the operating day. The reason is that in addition to its day-ahead payment of $50, by arranging fuel then has expected energy net revenue of $10 (a 20% chance of high demand with a $120 LMP – $70 marginal cost yields a $10 expected energy margin), and it *avoids* the $6 expected net loss if it does not arrange fuel (*see* Table 5-1, row [10]). The maximum it would be willing to spend to arrange fuel is therefore $50 + $10 + $6 = $66.

[66] In Sections 2.2.2 and 2.4.2, we also provided several variations on Example 1 with different assumptions (*e.g.,* when PFP applies). It can be shown that these same conclusions about the efficacy of the day-ahead ancillary service award hold for all of those Example 1 variations as well (we omit the detailed calculations here).

existing energy-only day-ahead market. It does so by resolving the misaligned incentives problem discussed in Section 2.

The structure of Example 2 lends itself to two additional points, which we highlight here. First, this example will show how day-ahead ancillary services, when settled as call options on real-time energy, work in concert with the real-time reserve settlements, based on the designations and prices from the real-time co-optimized dispatch in use today. We emphasized this approach earlier in Section 4.3, where we initially noted the combined day-ahead ancillary service and real-time reserve settlement logic (*see* case (j) in Section 4.3.2).

Second, in this example, the total market revenue – and therefore the total E&AS payments by wholesale buyers (and, ultimately, by consumers) – is higher under the Energy Security Improvements design than under the existing energy-only day-ahead market. This is true even though the new design produces more efficient outcomes – that is, the power system operates more cost-effectively (at lower total production costs) overall. We expect these observations to hold in practice.[67] The principal reason for the increase in total day-ahead market payments is that the market will now compensate suppliers, at transparent, competitive prices, for the ancillary services that the ISO has always relied upon in preparing the system's next-day operating plan. Suppliers are not compensated for those nonetheless-relied-upon services today, to the detriment of a cost-effective system.

► **Example 2: A recap.** In Example 2 from Section 2.8, there are four generators that can provide both energy and operating reserve. Real-time demand is uncertain, and the higher-cost generators (Generator 3 and Generator 4) do not receive day-ahead market energy awards. Generator 3 faces the possibility that real-time demand may be high enough for it to operate the next day, and it must decide whether or not to incur the cost of arranging fuel in advance of the operating day. The main assumptions, from Table 2-5, are reproduced below for convenience.

The additional market-level assumptions for Example 2 are a day-ahead energy demand of 190 MWh for the hour, and a reserve requirement (now both day-ahead and real-time) of 30 MWh for the hour.

[67] These observations are consistent with the principal findings of the Impact Assessment. In most cases studied, the Energy Security Improvements result in higher total energy and ancillary service market *payments* to suppliers overall, and simultaneously *lower* total production costs. *See* Impact Assessment at Table 22 (Difference in Production Costs, Winter Central Case), Table 25 (Total Payments, Winter Central Cases), and Table 35 (Non-Winter Total Payments, Non-Winter Central Cases).

Table 2-5. Assumptions for Example 2			
Generator	**Capacity (MW)**	**Offer Price ($/MWh)**	**Reserve Capability (MW)**
Gen 1	100	$25	10
Gen 2	100	$30	20
Gen 3	50	$40	30
Gen 4	50	$90	40
Additional Cost Assumptions for Generator 3			
		Marginal Cost	**Up-Front Cost**
With Advance Fuel Arrangements		$40	$150
No Advance Fuel Arrangements		N/A	N/A
Real-Time Demand Scenarios			
	Low Demand	**Medium Demand**	**High Demand**
Energy Demand (MWh)	170	190	210
Scenario Probability	33%	33%	33%

In analyzing Example 2 in Section 2.8, the key results we obtained were:

- The expected system total production cost is **$5,233** for the hour, if Generator 3 arranges fuel in advance of the operating day, and **$5,400** if it does not. (*See* Tables 2-6 and 2-7 in Section 2.8.1). This difference, or $167, is more than enough to cover the $150 up-front cost of the fuel arrangements. Thus, the most efficient, cost-effective outcome for the system would be achieved if Generator 3 makes the arrangements for fuel in advance of the operating day.

- If Generator 3 does not arrange fuel, it produces zero energy in real-time (in any demand scenario) and its expected net revenue is $0. If it does arrange fuel, Generator 3's expected net revenue is a net financial loss of $150. (*See* Table 2-8 in Section 2.8.2). In other words, arranging fuel in advance was not financially prudent for Generator 3.

- Under the current energy market construct, which does not provide sufficient incentive for Generator 3 to arrange fuel, the expected total day-ahead and real-time market settlement is **$6,100** for the hour. (*See* Table 2-7 in Section 2.8.1).

From the analysis of these results in Sections 2.8, our principal conclusion is that that the energy market, in its *current* form with real-time co-optimized energy and reserves, would not provide sufficient incentives for Generator 3 to incur the cost of arranging energy supplies in advance – even though making those arrangements would be cost-effective from the system's standpoint. Under the status quo, the generator's incentives are misaligned with society's interest in operating an efficient, least-cost power system.

5.2.1 Example 2 with Day-Ahead Ancillary Services as Energy Options

Now let's examine how the outcomes change if Generator 3 has a day-ahead ancillary service award defined (and settled) as an option on real-time energy. Our point is to illustrate that such a product serves to align the incentives properly: Generator 3 will find it in its private interest to arrange fuel in advance of the operating day, and that action is cost-effective from the system's standpoint.

As in Section 2.8, the timeframe in this updated version of Example 2 is a single delivery hour. Since Example 2 focused on co-optimization of energy and operating reserves, it will be useful to interpret the day-ahead ancillary service here as specifically providing the new generation contingency reserve day-ahead ancillary service. The broader conclusions below are not restricted by that interpretation, however. As in Example 2 earlier, we assume (for simplicity) a single day-ahead ancillary service product and a single real-time operating reserve product.

We make the following assumptions about day-ahead ancillary service pricing:

- The strike price is $35/MWh. This is approximately the average value of the real-time LMP in this example, consistent with the concepts discussed in Section 4.5 on strike prices.

- The day-ahead ancillary service offer price from low-cost Generator 2 is $1.67/MWh, from medium-cost Generator 3 is $11/MWh, and from high-cost Generator 4 is $17/MWh.[68]

The assumptions about the offer prices for day-ahead ancillary services from Generators 2, 3, and 4 are consistent with profitable offers for those services from each generator, given the competition they face in the day-ahead market (with one another) for both energy and for ancillary services, under the assumption that their costs of arranging fuel in advance of the operating day to cover a day-ahead ancillary service award are $100, $150, and $150, respectively. Since Generator 3 was assumed to have an up-front cost of arranging fuel of $150 throughout Example 2, the substantive new assumption is that Generator 2's cost is lower (at $100), and Generator 4's (at $150) is no less than Generator 3's.[69]

► **Day-ahead market awards and clearing prices.** With the above setup, we first evaluate the day-ahead E&AS market outcomes. This will differ from the day-ahead market outcome when there was no day-ahead ancillary service, shown previously in Figure 2-1 in Section 2.8.1.

The day-ahead market outcome with both energy and the day-ahead ancillary service is shown in Figure 5-1. The two lower-cost generators (Generator 1 and Generator 2) receive day-ahead energy

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[68] In Example 2 with a strike price of $35/MWh, the expected close-out cost for the energy option is $1.67/MWh and that is the minimum price at which a low-cost seller would be willing to accept a day-ahead ancillary service obligation.

[69] The salient assumption here is the ordering of these up-front costs among the higher-cost generators (*i.e.*, that Generator 4's are similar to, or greater than, Generator 3's). This example's conclusions would generally follow with different numerical values that respect these cost relationships.

awards, and Generator 2 and Generator 3 receive day-ahead ancillary service awards. The total ancillary services procured (just) satisfies the day-ahead requirement of 30 MWh for the hour.

The marginal ancillary services provider is Generator 3, which sets the day-ahead ancillary service clearing price at its ancillary service offer price of $11/MWh.

The day-ahead LMP is $39.33/MWh, and reflects the pricing of *both* energy and ancillary services offers. Specifically, the highest-priced offer for energy cleared in the day-ahead market is that of Generator 2, at $30/MWh. The LMP is not set by just one generator's offer price, however. It is set by the change in the system's total production cost that would be incurred if there were another increment of energy demand. That, in turn, would require a "re-dispatch" of the ancillary services awards, which produces the $39.33/MWh day-ahead LMP for energy.

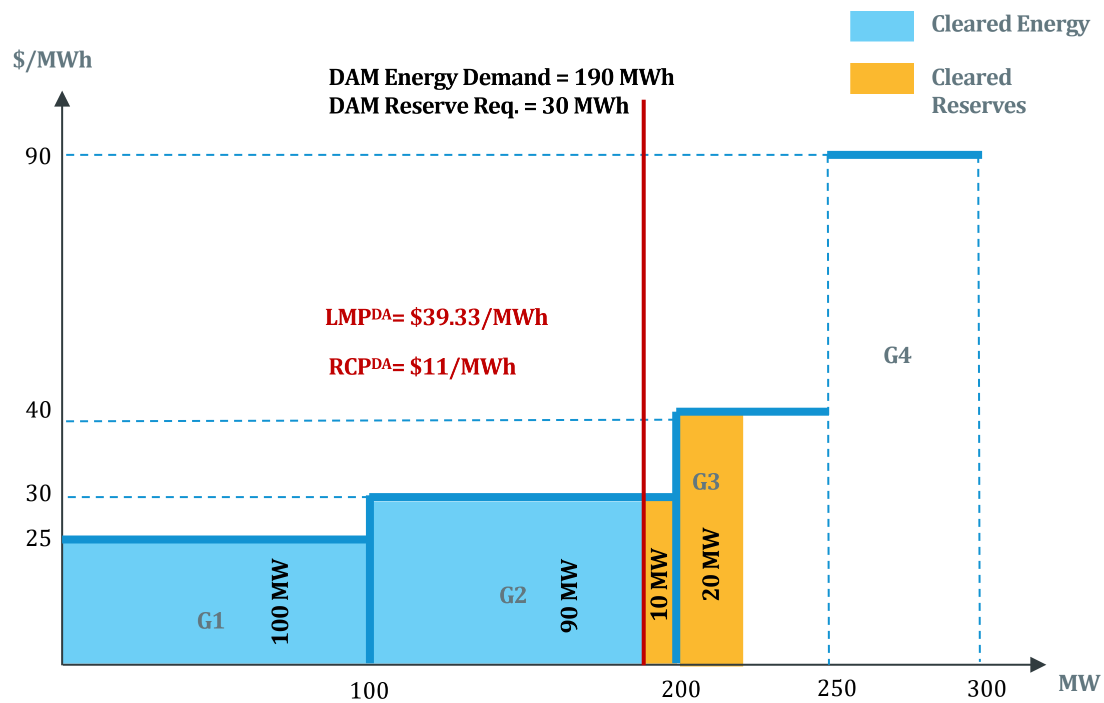

Figure 5-1. Day-Ahead Market Outcomes for Example 2, with Energy and Ancillary Service

To see this more precisely, let us step through this "re-dispatch" logic. Suppose day-ahead energy demand increased from 190 MWh, by 1 additional MWh. The least-cost solution would then increase the energy cleared from marginal Generator 2, at an incremental cost of $30/MWh (its energy offer price). However, that additional cleared energy reduces Generator 2's available MWh for ancillary services by 1 MWh, from 10 MWh to 9 MWh. To replace that 1 MWh of ancillary service and still satisfy the day-ahead ancillary services requirement, the market would then clear 1 additional MWh of ancillary service from Generator 3. The net cost of this "re-dispatch" of 1 MW of ancillary service from Generator 2 (which offered the ancillary service at $1.67/MWh) to Generator 3 (which offered at $11/MWh) is therefore the difference in their offer prices, or $11 – $1.67 = $9.33/MWh. Putting it all together, the incremental cost of another 1 MWh of *energy* demand, while still maintaining the day-ahead ancillary service requirement, is $30 + $9.33 = $39.33/MWh. The day-ahead LMP for energy is, therefore, $39.33/MWh.

In this way, creating a day-ahead co-optimized E&AS market raises the day-ahead energy price – and the revenue of all day-ahead cleared resources with energy awards – relative to a day-ahead energy market alone. With the day-ahead ancillary service, the day-ahead LMP is $39.33/MWh; by contrast, in Example 2 without the day-ahead ancillary service, the day-ahead LMP was only $30/MWh (*see* Table 2-6 in Section 2.8.1).

That is a broader and general point; while the day-ahead E&AS market clearing will not *always* produce a higher day-ahead energy compensation than would a day-ahead energy-only market, the co-optimization of energy and ancillary services will tend to produce that outcome (depending, in practice, on resources' offers, demands, and so on). We will explain this point further, with additional examples, in Sections 6 and 7.

The day-ahead E&AS clearing here also illustrates another, more subtle observation: with a co-optimized E&AS market with ancillary service *offers,* the LMP for energy may not be set by the offer price of any one resource alone. Rather, it may be set by a combination of several resources' energy and ancillary service offer prices. In this way, the day-ahead price of energy may commonly reflect one (or more) suppliers' offer prices.

► **Full market awards and outcomes.** The real-time market outcomes for Example 2 with the day-ahead E&AS market remain unchanged from those shown previously in Example 2 in Section 2.8.1. (*See* Figures 2-2, 2-3, and 2-4.)

For reference, the full set of market outcomes for the case when Generator 3 arranges fuel in advance (Case A) are shown in Table 5-2 below; and when Generator 3 does not arrange fuel in advance (Case B), in Table 5-3 below. Cell differences from Table 5-2 to Table 5-3 are shaded in light orange in Table 5-3 to facilitate comparisons.

We will address Generator 3's decision next, and then turn to the implications for total system production costs and total market payments (shown in rows [9] and [11] of Tables 5-2 and 5-3) in subsequent Section 5.4.3.

Table 5-2. Market Outcomes for Example 2 with Day Ahead E&AS Market, Case A: Generator 3 With Fuel										
		Day Ahead		Real-Time Market Outcomes						
		Market Awards		Low Demand		Medium Demand		High Demand		
	Generator	Energy	Option	Energy	Reserve	Energy	Reserve	Energy	Reserve	
[1]	Gen 1	100	0	100	0	100	0	100	0	
[2]	Gen 2	90	10	70	20	90	10	100	0	
[3]	Gen 3	0	20	0	30	0	30	10	30	
[4]	Gen 4	0	0	0	40	0	40	0	40	
[5]	**Totals**	190	30	170	90	190	80	210	70	
[6]	**Clearing Price**	$39.33	$11.00	$30.00	$0	$30.00	$0	$40.00	$0	
[7]	Scenario Total Production Cost			$4,600		$5,200		$5,900		
[8]	Demand Probability			33%		33%		33%		
[9]	**Expected Total System Production Cost**					**$5,233**				
[10]	Scenario Market Payments (incl. DAM)			$7,203		$7,803		$8,453		
[11]	**Expected Total Market Payments**					**$7,819**				

Table 5-3. Market Outcomes for Example 2 with Day Ahead E&AS Market, Case B: Generator 3 Without Fuel									
		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Option	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	0	100	0	100	0	100	0
[2]	Gen 2	90	10	70	20	90	10	100	0
[3]	Gen 3	0	20	0	30	0	30	0	0
[4]	Gen 4	0	0	0	40	0	40	10	40
[5]	**Totals**	190	30	170	90	190	80	210	40
[6]	**Clearing Price**	$39.33	$11.00	$30.00	$0	$30.00	$0	$90.00	$0
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,400	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$5,400**			
[10]	Scenario Market Payments (incl. DAM)			$7,203		$7,803		$7,953	
[11]	**Expected Total Market Payments**					**$7,653**			

5.2.2 Generator 3's Decision with the Day-Ahead Ancillary Service Award

Given these market outcomes, let's now examine what decision maximizes Generator 3's expected net revenue. For this, we make use of the full market outcome results (in Tables 5-2 and 5-3) with the day-ahead E&AS market and the general energy-option settlement rules, as discussed in Section 4.3. Table 5-4 shows Generator 3's expected net revenue, for the case where it arranges fuel (Case A) and the case when it does not (Case B).

Table 5-4. Generator 3's Expected Net Revenue for Example 2 with Day-Ahead E&AS Market

			Case A: With Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Day Ahead Energy Close-Out	*-RT LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[3]	Day Ahead Option	*DA RCP * Qo_DA*	$ 220	$ 220	$ 220	$ 220	$ 220	$ 220
[4]	Day Ahead Option Close-Out	*-max(RT LMP-K, 0)* Qo_DA*	$ -	$ -	($100)	$ -	$ -	($1,100)
[5]	Real-Time Energy	*RT LMP * Qe_RT*	$ -	$ -	$ 400	$ -	$ -	$ -
[6]	Real-Time Reserves	*RT RCP * Qr_RT*	$ -	$ -	$ -	$ -	$ -	$ -
[7]	**Total Settlement**	[1]+[2]+[3]+[4]+[5]+[6]	$ 220	$ 220	$ 520	$ 220	$ 220	$ (880)
Generator's Costs								
[8]	Advance Fuel	*F*	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[9]	Variable Cost	*MC*	$ -	$ -	$ (400)	$ -	$ -	NA
[10]	**Total Cost**	[8]+[9]	$ (150)	$ (150)	$ (550)	$ -	$ -	$ -
Generator's Expected Profit								
[11]	Scenario Net Revenue	[7]+[10]	$ 70	$ 70	$ (30)	$ 220	$ 220	$ (880)
[12]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[13]	**Expected Net Revenue**	SumProd [11]x[12]		$37			($147)	

In row [3] of Table 5-4, we show that Generator 3 receives a day-ahead market ancillary service credit of $220, on an award of 20 MWh of ancillary service at the $11 day-ahead clearing price for the ancillary service (shown as 'DA RCP' in row [3]).

In row [4], we show its close-out of its day-ahead option award settlement. In Case A, the real-time LMP in the high demand scenario is $40/MWh, just above the strike price of $35/MWh, so this settlement amount is a charge of $100:

$$-20 \text{ MWh} \times \max\{0, RT\ LMP - K\} = -20 \text{ MWh x } \max\{0, \$40 - \$35\} = -\$100.$$

In Case B, where the generator does not have fuel, the real-time LMP in the high demand scenario is $90/MWh so this settlement amount is a much greater charge:

$$-20 \text{ MWh} \times \max\{0, RT\ LMP - K\} = -20 \text{ MWh x } \max\{0, \$90 - \$35\} = -\$1100.$$

Next, rows [5] and [9] show that the generator's energy revenue and variable fuel costs are a wash. This is because Generator 3 offered energy at its marginal cost and sets the real-time LMP in the only scenario when it produces energy, so it has no energy margin on its real-time energy output. Row [8] shows Generator 3's $150 up-front cost of arranging fuel, for the Case A scenarios when it does so.

The bottom row of Table 5-4 summarizes the results. Generator 3's expected net revenue, if it arranges fuel, is now $37. Arranging fuel is now a profitable endeavor, even though there is only a 33% chance it would be used. Compare this with Generator 3's decision when there is no day-ahead ancillary services market, as shown in Table 2-8 (*see* Section 2.8.2). In that earlier version of this example without the energy option design, it was not in Generator 3's financial best interest to arrange in advance for fuel, and hence did not run at all and had expected net revenue of zero.

Last, Table 5-4 shows that if Generator 3 clears the day-ahead ancillary services position of 20 MWh, but then does not arrange fuel, its expected net revenue is a financial loss of $147. Stated simply, the risk of financial loss if a supplier sells day-ahead ancillary services and does *not* arrange fuel in advance of the operating day creates the economically-correct consequence to solve the mis-aligned incentive problem – and to address the region's fuel security concerns.

The immediate point to emphasize is that with day-ahead ancillary services settled as call options on energy, and a co-optimized day-ahead E&AS market, Generator 3 would be willing to incur the $150 up-front cost of arranging fuel in advance of the operating day. Indeed, in this example, Generator 3 would be willing to accept a day-ahead ancillary service award at a clearing price down to (just above) $9.17/MWh, as that would yield a positive expected profit – still better than the zero expected net revenue it would obtain under its best alternative without a day-ahead ancillary services award (*see* Section 2.8.2, Table 2-8, bottom right cell).

5.2.3 Implications: The Incentives of Replacement-Cost Settlements

The implication of this example, and our reason for revisiting it, is important: the opportunity to sell a real option on energy, as a day-ahead ancillary service, improves the generator's willingness to undertake a costly investment in arranging fuel – even knowing that the arrangement may not be used.

In this example, that willingness arises because the generator's valuation of the investment is no longer based solely on the $40/MWh real-time LMP that it earns when it has fuel and supplies energy in real-time. Instead, its valuation of the investment is also based on the $90/MWh real-time LMP that society *avoids* if it makes the investment. This $90/MWh real-time energy price is accounted for in the generator's financial calculus in row [4] of Table 5-4., where it drives the steep $1,100 charge if Generator 3 fails to cover its day-ahead ancillary service position by not arranging fuel, and the high-demand scenario where it would be called to operate (if available) occurs.

As noted previously, this function of real-option settlements is quite general, as it aligns the generator's and society's incentives to similarly account for the same, high $90/MWh cost of "replacing" Generator 3's energy whenever it holds an ancillary service obligation but does not perform. As a result, there is no divergence between the value that society places on the investment in its energy supply arrangements, and the value that the generator places on the same investment. The real-option design of the day-ahead ancillary service product solves the misalignment problem, and would lead the generator to incur the fixed costs of making energy supply arrangements whenever they would be cost-effective for the system as a whole.

That property is a general one with this real-option design of a day-ahead E&AS market. We could create numerous additional examples, but they would all demonstrate the same conclusion: a real-option design of a day-ahead E&AS market aligns a resource owner's incentives to invest in energy supply arrangements with the replacement cost that society would incur, at the margin, if it fails to do so. As a result, there will no longer be a divergence between the social and private benefit of the investment. Put succinctly, this market design solves the misaligned incentives problem.

For completeness, it is important to emphasize that this does not imply lower levels of total payments by wholesale buyers (or, ultimately, consumers). Under the status quo, when Generator 3 was not incented to arrange fuel (and the higher-cost generator must be used in its place during high-demand scenarios), the total market payments were $6,100 (*see* Table 2-7 in Section 2.8.1, bottom row). Under the day-ahead E&AS design, where Generator 3 arranges fuel in advance and the system's expected total production costs are *lower,* the total market payments are *higher*, at $7,819 (*see* Table 5-2, bottom row).

The reason for this increase in total market payments is that the new day-ahead E&AS market is now compensating resources for the ancillary services capabilities that the ISO, and ultimately consumers, rely upon as part of the system's next-day operating plan – but that are not presently compensated in the existing market construct. With the day-ahead E&AS market design, the market will now signal, through transparent prices, the total cost of maintaining a reliable power system.

5.3 The Strike Price Creates Economic Incentives

In the examples above, we showed how the energy option design strengthens generators' incentives to arrange fuel. Further, the additional costs that generators are willing to incur to make those arrangements, in light of the new day-ahead ancillary service market with its option-based settlement, are fully aligned with the system's benefits from doing so.

There is one important design element that these conclusions rest upon that merits additional discussion. As noted in the Section 4.5 discussion on energy option strike prices, these beneficial incentive properties are dependent on the strike price not being set 'too high.' If it is, these incentives may be undermined and the benefits of the Energy Security Improvements would be lessened.

In this section, we provide a more detailed rationale for how the strike price should be set to achieve efficient incentives. This analysis also will help to clarify why, in practice, small inaccuracies in setting the strike price should not matter much, within limits (*see* Guideline 3 in Section 4.5.1).

5.3.1 Incentive Profiles

In Section 4.5.1, we indicated that, in general, an energy option will provide a day-ahead ancillary service seller with efficient marginal incentives to cover its award (that is, to arrange fuel) when the strike price is set at, or below, its resource's marginal cost of producing energy. To explain why this is the case, some insights from Example 2 will be helpful.

In general, the impact of the strike price on a day-ahead ancillary service seller's incentive to arrange fuel has a nonlinear relationship. Specifically, the incentive, defined as the maximum amount that the generator that sells an energy call option would be willing to spend, is high (and constant) over an initial range of potential strike price levels, and then declines steadily as the strike price rises. At very high strike prices, the incentive may be completely eviscerated. We refer to this as a resource's *incentive profile* curve. For Generator 3 in Example 2 above, its incentive profile curve looks like this:

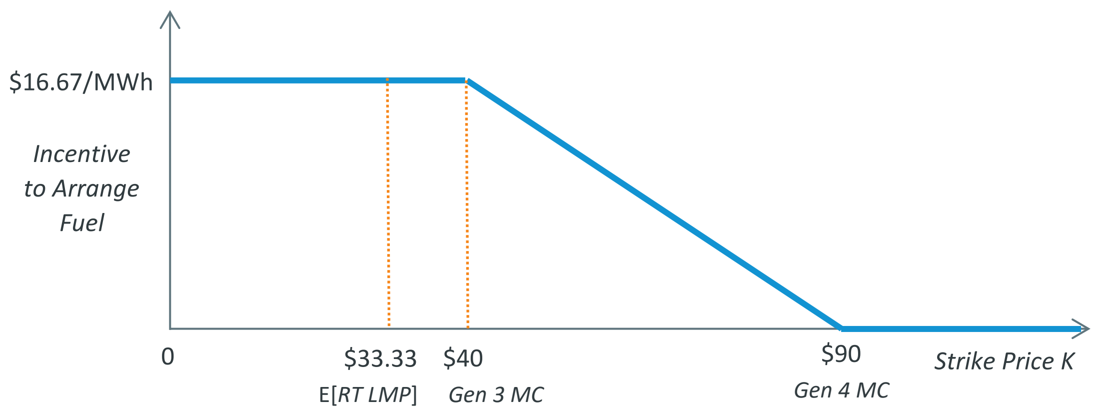

Figure 5-2. Generator 3's Incentive Profile in Example 2

In this graph, the horizontal axis depicts a range of possible strike price values, from zero at the left to higher possible strike price values toward the right. The vertical axis, characterizing its financial incentive, is the maximum amount that the generator that sells an energy call option would be willing to spend, up front, to arrange fuel.[70] (We'll explain the numerical values in Figure 5-2 momentarily.)

[70] A note regarding Figure 5-2: this graph appears similar to, but is substantively different from, textbook diagrams of option payoffs (which also have a flat-then-sloped segment). In textbook diagrams, the strike price is a fixed number and the horizontal axis depicts a varying spot price. In this diagram, the horizontal axis depicts a varying strike price, which is a different analysis.

The incentive inducing a generator to make advance fuel arrangements is maximized on its initial segment, where the curve is flat. If the strike price is set within that range, a seller will fully internalize the impact of its potential non-availability on the real-time LMP. Above a certain level, however, increases in the strike price limit the option's close-out cost if it does not have fuel to operate, and the seller's incentive to arrange fuel for its resource declines.[71] Toward the far right, if the strike price is set far too high, then the close-out charge becomes both *de minimus* and rare (the option is too far "out of the money"). In other words, if the strike price is set too high, the energy option's benefit in incenting fuel becomes zero (for the reasons noted at the start of Guideline 2 in Section 4.5.1).

Next, consider the numerical values shown in Figure 5-2. These will help convey why the strike price is key to achieving efficient marginal incentives for beneficial energy supply arrangements from the system's standpoint.

Recall that in Example 2, we assumed the strike price was $35/MWh. This value falls between the expected value of the real-time LMP, which is $33.33/MWh, and Generator 3's marginal cost of $40/MWh, both shown in Figure 5-2 above.[72]

At the $35/MWh strike price level on the horizontal axis, the $16.67/MWh value shown on the vertical axis represents the maximum cost that Generator 3 would be privately willing to incur to arrange fuel in advance of the operating day. This value is determined by Generator 3's expected option close-out cost if it arranges fuel in advance, versus if it does not. This is evident from Generator 3's settlements in each case:

- From Table 5-4, if Generator 3 has advance fuel, there is a 33% chance it will incur a close-out charge of $100 (see row [4], "high demand" column of Case A).

- In the alternative, if Generator 3 does *not* arrange fuel in advance, then there is a 33% chance of a much higher close-out charge of $1,100 (see row [4], "high demand" column of Case B).

- The expected difference in these market settlement costs for Generator 3 is therefore 33% × [$1,100 – $100] = $333.33 in total. Note that Generator 3's day-ahead ancillary service award is 20 MWh (*see* Table 5-2, row [3]). Therefore, on a per-MWh basis, its expected additional financial consequence in market settlements if it does *not* arrange fuel in advance (relative to if it does) is a charge of $16.67/MWh.

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[71] We simplify slightly. Stated more precisely, above a certain level, increases in the strike price limit the *difference* in the expected value of the seller's option close-out costs if the seller is not able to supply energy in real-time, relative to its (lower) expected close-out cost if it is able to supply energy in real-time.

[72] The expected real-time LMP of $33.33 is equal to the (probability-weighted) average of the three possible energy clearing prices shown in row [6] of Table 2-6 in Section 2.8.1.

This calculation explains why the height of the incentive profile for Generator 3, at a strike price of \$35/MWh, is equal to \$16.67/MWh in Figure 5-2.[73] One can perform similar calculations for alternative strike prices, using the same settlement calculation logic summarized in Table 5-4 (we omit the details here). For strike prices ranging from \$0 up to Generator 3's marginal cost of \$40/MWh, the results will be the same: over the region up to the generator's marginal cost, its incentive to arrange fuel is constant, at \$16.67/MWh. That is the maximum amount Generator 3 would be willing to spend, up-front, to arrange fuel with a day-ahead ancillary service obligation.

If the strike price is greater than its marginal cost, however, its incentive to arrange fuel declines. In this example, the rate at which its incentive declines is \$0.33/MWh for every \$1 increase in the strike price above \$40. This rate occurs because there is only a 33% (or 0.33) chance that Generator 3's fuel arrangements will impact the real-time LMP (compare the real-time LMPs in row [6] of Tables 5-2 and 5-3, which differ only in the high-demand scenario, which occurs with a 33% chance).

Its incentive becomes zero if the strike price is \$90/MWh or above, which is the maximum possible real-time LMP in this example. At a strike price of \$90/MWh or more, Generator 3's close-out costs would always be zero if it does not arrange fuel, and it would have no economic incentive to do so since that the fuel is mostly likely not to be needed.

And yet, as we will explain in Section 5.3.2 next, it would be in society's best interest if it did.

► **Implications.** A key insight about the energy option design is that generators will, as a general property, have a flat initial segment of their incentive profile curves for strike prices up to their real-time marginal cost of energy. This region is where its incentives are maximized.

At strike prices above that point, a generator's incentives for energy supply arrangements decline. This too occurs generally. If the strike price is greater than a resource's marginal cost of producing energy, there will be range of real-time energy prices (prices above its marginal cost and below the strike price) for which it would be economic for the resource to operate – *if* it has arranged fuel – but for which the resource will face no option close-out charge if it has not. The absence of financial consequences in this price range diminishes the resource owner's private incentive to arrange fuel in advance of the operating day. And the higher the strike price, the more its incentives diminish.[74]

[73] For the curious, this result can also be obtained directly using the last row [13] in Table 5-4. There, the difference in Generator 3's expected net revenue with versus without fuel is \$37 – (– \$147) = \$184, which when added to its \$150 up-front cost to arrange fuel, is \$184 + \$150 = \$334; on a per-MWh basis, this is \$334/20 MWh = \$16.7, interpretable (as before) as Generator 3's maximum willingness to spend, up front, to arrange fuel in advance.

[74] In more general settings beyond Example 2, a generators' incentive profile will have a flat segment where its incentive is maximized for strike prices up to (at least) its marginal cost of energy. However, the linear decline above the generator's marginal cost in Figure 5-2 is an artifact of the discrete price outcomes in Example 2; in general, the downward sloping segment above a generator's marginal cost is nonlinear, with a shape determined by the full probability distribution of the real-time price with and without the generator's energy supply. Such technicalities do not change the practical implication that the incentives are maximized when the strike price is set below a resource's marginal cost.

5.3.2 Strike Prices and Efficiency

So far, we have explained why setting the strike price too high – above a resource's marginal cost – will diminish its incentives to arrange energy supplies in advance of the operating day. Will setting the strike at (or below) a resource's marginal cost provide marginal incentives for energy supply arrangements that are cost-effective from society's standpoint? The answer is yes.

To see this, let's first examine the expected benefits (*i.e.,* expected cost savings) from the system's standpoint when Generator 3 arranges fuel in advance, versus when it does not. Table 5-2 reports that the system's total production costs when Generator 3 arranges fuel is $5,233 (*see* row [9]); without rounding, that value is $5,233.33. Table 5-3 reports the system's total production costs when generator 3 does *not* arrange fuel is higher, at $5,400 (*see* row [9]). The difference is the system's expected cost savings, or $5,400.00 – $5,233.33 = $166.67.

Let's convert that into a $-per-MWh basis. Here, the key is to note that if Generator 3 acquires the energy option obligation, but if it does *not* arrange fuel, the *quantity* of energy that must be "replaced" with energy from higher-cost Generator 4 is 10 MWh (*see* Table 5-3, where the cell shaded light orange in row [4] shows 10 MWh for Generator 4's energy, in the high demand scenario). This means that, on a per MWh basis, the system's expected cost savings when Generator 3 arranges fuel in advance, versus when it does not, is $166.67 / 10 MWh = $16.67/MWh.

► **Implications.** The implication of this analysis is important: the flat segment of a resource's incentive profile is where its marginal private incentive to make costly fuel supply arrangements is aligned with the benefit of doing so from society's standpoint. That is, if the strike price is set at (or below) the generator's marginal cost of energy, then it will fully internalize, in its financial calculus, the high cost that prevails if it cannot operate when its generation is in demand.

In Section 5.3.1, we showed that from the perspective of Generator 3's private financial incentive, if its day-ahead ancillary services award has a strike price at or below $40/MWh, then the cost it would be willing to incur to arrange fuel in advance is $16.67/MWh. Then, from the calculations above in this Section 5.3.2, we see that the expected benefit (*i.e.,* expected cost savings) to the system if Generator 3 arranges fuel in advance of the operating day is also $16.67/MWh. In sum, the resource's private incentives to arrange fuel are fully aligned with the system benefits from doing so, as should occur in a sound market design.

The general point is simple. To provide efficient marginal incentives, the strike price should be set at or below a day-ahead ancillary service seller's marginal cost of energy (for the corresponding delivery hour). A strike price that is set higher than that will tend to mute incentives to invest in energy supply (*i.e.,* fuel) arrangements, undermining both the incentives *and* the cost-effectiveness of the new day-ahead ancillary services design.

There are two other important points from this analysis, related to Guidelines 2 and 3 discussed earlier, in Section 4.5. First, if the strike price is set at the expected value of the real-time LMP, then resources that provide ancillary services will tend to be on the flat segments of their incentive profiles – even though the real-time LMP may be below their marginal costs. This will still provide efficient marginal incentives and preserve the cost-effectiveness of the overall design.

Figure 5-2 illustrates this point. There, if Generator 3 arranges fuel, it has a marginal cost of \$40/MWh, and the expected real-time LMP is \$33.33/MWh. A strike price at the expected real-time LMP provides the same incentive to arrange fuel in advance (of \$16.67/MWh) as does a strike price at its marginal cost, because its incentive profile is flat at strike prices below its marginal cost. That is, if Generator 3 acquires an ancillary service obligation for which the ISO sets a strike price at the expected real-time LMP of \$33.33/MWh, the generator would still have efficient incentives to arrange fuel supplies.

While these particular numbers are specific to this example, they illustrate a property that we expect from the markets generally. As discussed earlier, in Section 4.5.1, in the real-time markets, resources that have lower marginal costs than the real-time energy price are committed and dispatched to supply energy. Resources, or portions thereof, that have higher marginal costs than the real-time energy price are designated by the dispatch to supply reserves (provided they have the requisite response and ramping capabilities).[75] For that reason, the desired incentives can be reasonably achieved by setting the strike price at the expected real-time energy price. In doing so, the energy option design will provide much stronger incentives than today for resources to make greater energy supply arrangements to ensure their resources can perform when needed.

The second point to note from this analysis relates to Guideline 3 in Section 4.5.1. There, we noted that small inaccuracies in estimating the expected real-time energy price when setting the strike price should not have large effects, at least within limits. The structure of resources' incentive profiles with energy option awards, as illustrated in Figure 5-2, helps explain why.

Specifically, if the strike price is set too low, that will tend to place more sellers of day-ahead ancillary services on the flat segments of their incentive profile curves. For example, in Figure 5-2, if the strike price is set at (say) \$30/MWh, rather than at the true expected value of the real-time LMP of \$33.33/MWh in this example, then Generator 3 continues to have the same marginal incentive to arrange fuel in advance of the operating day, whenever such arrangements are cost-effective from the system's standpoint. For that reason, a strike price that is set lower than the expected real-time energy price does not weaken the incentives (or efficiency) of the energy option design.

The consequences of setting the strike price too high depend on the magnitudes – thus our point about limits. Using Figure 5-2 again for example, the strike price of \$35/MWh is higher than the expected value of the real-time LMP of \$33.33/MWh, and does not change the generator's incentives – since it remains on the flat segment of its incentive profile, where its incentives are maximized. However, a strike price set (say) \$10/MWh higher than the expected real-time LMP would be \$43.33/MWh and would exceed the generator's marginal cost, and begin to erode its incentives (in this example). In essence, in this example, there is a "margin for error" of

$$\$40 \textit{ marginal cost} - \$33.33 \textit{ expected real-time LMP} = \$6.67 \text{ / MWh}$$

[75] As noted previously, there are "redispatch" exceptions, but they would not tend to make it efficient to set the strike price *above* the expected real-time LMP. *See* footnote 60 above and accompanying text.

for inaccuracies in the direction of a strike that is too high, before the generator's incentive are affected. Since most generators that provide reserves tend to have marginal costs higher than the real-time energy price, we conclude that small inaccuracies in setting the strike price "at the money" should not matter much – within limits.

5.4 Options on Energy versus Forward Sales of Reserves

As discussed in Section 4, all of the new day-ahead ancillary services – energy imbalance reserve, generation contingency reserve, and replacement energy reserve – will be settled as call options on real-time energy. This means that the day-ahead market will procure options on real-time energy from physical resources; not ancillary services that settle against resources' anticipated real-time reserve designations.

During the stakeholder review process of these Energy Security Improvements, we discussed why this energy option settlement design provides superior incentives to alternative settlement rules that are based on the real-time reserve price. That alternative is most relevant in the context of generation contingency reserves, because the ISO's existing real-time markets presently designate and price real-time reserves for ten-minute and thirty-minute reserve products as well.

In Section 4.3, we explained that the energy option settlement design all works smoothly if day-ahead generation contingency reserve (that is, day-ahead TMSR, TMNSR, and TMOR) awards are settled as call options on energy, and then designated and priced in real-time based on the co-optimized real-time market in use today (*see, e.g*. example (j) in Section 4.3.2). And, as explained in detail in the context of Examples 1 and 2 throughout this Section 5, the real-option design of the day-ahead ancillary service solves the misalignment problem, and would lead resource owners to incur the costs of making energy supply arrangements whenever they would be cost-effective for the system as a whole.

Mechanically, it is also possible to settle day-ahead reserve obligations as deviations against the real-time reserve price, rather than as options on energy. That alternative settlement rule is used in some other ISOs in other regions, though the North American ISOs/RTOs' day-ahead reserve market designs vary greatly.[76] In general, settling day-ahead reserve obligations as deviations against the real-time reserve price, rather than as options on energy, will produce different payments and (very) different incentives, particularly during periods in which fuel supplies may be scarce and energy security concerns are most significant.

In this section, we discuss why resources' incentives to arrange more robust energy supply (*i.e*., fuel) arrangements are superior – *i.e*., more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward

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[76] *See* Energy Security Improvements: Market-Based Approaches, Day-Ahead Reserves - Alternative Settlement Design and its Fuel Security Implications, Presentation to NEPOOL Markets Committee, dated December 10-11, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_iii_presentation_da_reserves_alternative_settlement_design_fs_implications.pptx, at Slides 11, 42.

sale of real-time reserve designations. The central issue is that when day-ahead obligations for essential reliability services are settled against the reserve price, rather than against the energy price, then sellers will not fully internalize the high price for energy that society pays if fuel is scarce and a resource is unable to operate when needed. As a result, under alternative settlement designs based on the real-time reserve price, a generator's and society's interests remain mis-aligned and the incentives for resources to invest in additional energy supply (*i.e.* fuel) arrangements are significantly muted – particularly when those additional energy supply arrangements would be valued by society the most.

► **Terminology.** In this section, we will compare the incentives that stem from two alternative settlement rules for day-ahead ancillary services. With the energy option design in the Energy Security Improvements, the underlying product is a call option on real-time energy. With a forward reserves alternative design (sometimes called "reserve deviations"), the underlying product is a real-time reserve designation.

Mechanically and economically, the crucial design difference between the two is how the day-ahead ancillary service obligation is settled (or 'close-out'). Specifically:

- With the energy options design, day-ahead reserve awards are closed-out at the real-time energy price less the option strike price, when positive. A resource that is awarded a day-ahead reserve obligation and cannot operate in real-time would be charged in settlement:

  $$\text{DA Ancillary Service Award MWh} \times \max\{0, \mathit{RT\ LMP} - K\}.$$

- With the forward reserve design, day-ahead reserve awards are closed-out at the real-time reserve price (or, equivalently, real-time reserve deviations from day-ahead settle at the real-time reserve price). A resource that is awarded a day-ahead reserve obligation and cannot operate in real-time would be charged in settlement:

  $$\text{DA Ancillary Service Award MWh} \times \mathit{RT\ RCP}$$

  where *RT RCP* denotes the real-time reserve clearing price.

From the standpoint of economic incentives, the energy option settlement rule leads the resource owner to internalize its replacement cost of *energy* in real-time if it does not have fuel to operate. That can be a steep price – and can escalate quickly during stressed conditions if a resource cannot run when needed.

In contrast, the forward reserve settlement rule leads the resource owner to internalize its replacement cost of *reserve* in real-time if it does not have fuel to operate (and, even then, possibly only if it is called for energy, and its failure to have fuel is discovered). That is typically a much less steep price – and does not escalate as quickly, or to as high a level, during stressed condition if a resource cannot run when needed.

To see this most clearly, let us consider each of these two settlement designs in the context of Example 2, as discussed in Section 5.2 above.

► **Application to Example 2.** In Section 5.2.2, we considered Generator 3's decision to incur the up-front $150 cost to arrange fuel in advance of the operating day under the energy option design. In that example, Generator 3's decision impacts the real-time market only in the high-demand scenario, when its energy is needed to meet real-time energy demand (compare Tables 5-2 and 5-3, right hand columns, in Section 5.2.1).

As we examined in that example, under the energy option design, if Generator 3 does not have fuel (Case B), the real-time LMP in the high demand scenario is $90/MWh and Generator 3 faces a steep financial consequence in the market settlements, of:

$$-20 \text{ MWh} \times \max\{0, \text{RT LMP} - K\} = -20 \text{ MWh x } \max\{0, \$90 - \$35\} = -\$1100.$$

(*See* Section 5.2.2). This high-demand scenario has a 33% chance of occurring (Table 5-3, row [8]). Thus, if Generator 3 does not arrange fuel under the energy option design, it faces an expected cost in real-time settlement of

$$33\% \times (-\$1100) = -\$333.33.$$

That expected cost substantially exceeds the up-front $150 cost of arranging fuel. Thus, it is in Generator 3's private financial interest to arrange fuel – under the energy option design. In effect, Generator 3 is led to fully internalize the $90/MWh real-time LMP that will prevail (in the high-demand scenario) if it fails to arrange fuel in advance of the operating day.

Now consider the same situation under the alternative, forward reserve settlement design. In Example 2, in the high-demand scenario, the real-time reserve price if Generator 3 does not have fuel (Case B) is $0/MWh. *See* Table 5-3, row [6], last column. That means if Generator 3 does not have fuel (Case B), when real-time LMP in the high demand scenario is $90/MWh and the real-time reserve clearing price is $0/MWh, its financial consequence in the market settlements is:

$$-20 \text{ MWh} \times \text{RT RCP} = -20 \text{ MWh x } \$0 / \text{MWh} = \$0.$$

The high-demand scenario has a 33% chance of occurring (Table 5-3, row [8]). This means that if Generator 3 does not arrange fuel under the alternative reserve settlement design, it faces an expected financial consequence of zero.

Because it faces zero financial consequences if it does not arrange fuel in advance of the operating day, it is not in Generator 3's private financial interest to incur the $150 up-front cost of arranging fuel – under the alternative reserve settlement design. In effect, nothing in the alternative settlement rule leads Generator 3 to internalize the high $90/MWh real-time LMP that society will incur (in the high-demand scenario) if it fails to arrange fuel in advance of the operating day. The market's incentives fail.

► **Implications.** The point of this analysis is a general one, and it is important. As shown in Section 5.2.3 and 5.3.2, under the energy option design, resource owners have strong financial incentives to arrange energy supplies in advance, whenever society would benefit from doing so. But, for the reasons indicated in the preceding analysis, under the real-time reserve deviations settlement design, resource owners have far weaker incentives to arrange energy supplies in advance – even though it would be in society's best interest if they did.

At root, the problem here is that the real-time reserve deviations settlement design does not solve the misaligned incentives problem that exists in New England's existing market construct. In this example, the generator is not incented to invest in advance fuel arrangements using the alternative settlement design because the generator's valuation of that investment is based solely on the \$0/MWh real-time reserve settlement charge and the \$40/MWh real-time LMP that it earns when it has fuel and supplies energy in real-time. That is effectively same situation the generator faces today (*see* Section 2.8.2). In contrast, with the energy option design of the Energy Security Improvements, its valuation of the investment is now based on internalizing, in its own financial calculus, the \$90/MWh real-time LMP that society avoids if it makes the investment. And that alignment of incentives does solve the problem.

As noted in Section 5.2.3 earlier, we could create numerous additional examples but they would all demonstrate the same conclusion: the energy option design for the co-optimized day-ahead ancillary services market aligns a resource owner's incentives to invest in energy supply arrangements with the replacement cost that society would incur, at the margin, if it fails to do so. And we have designed the new day-ahead ancillary services as options on real-time energy precisely because of that strong incentive this design creates.

In sum, the incentives for resources to arrange more robust energy supply (*i.e*., fuel) arrangements are superior – *i.e*., more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward sale of real-time reserve designations. For that reason, the energy option design in these Energy Security Improvements is a far preferable improvement to the market design to better address regional fuel security concerns.

6. Energy Imbalance Reserve and the Forecast Energy Requirement

In this section, we provide details on the new Day-Ahead Energy Imbalance Reserve (EIR) ancillary service product. As explained previously, an energy 'gap' arises when resources' total day-ahead energy supply schedules are less than the ISO's load forecast, in one or more hours, during the next (operating) day. Under applicable reliability standards, ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast load each hour – not simply the level of demand cleared in the day-ahead energy market. This gap is Problem 3 – insufficient day-ahead scheduling – as described in Section 2.

Presently, the energy to cover this gap is supplied through the dispatch and post-market commitment of other resources operating above, or that did not receive, a day-ahead market award. As emphasized in Section 2, however, the existing market construct does not provide these resources with adequate incentives to have energy supply arrangements in place in advance of the operating day – even when it would benefit society if they did.

As explained in this section, with these Energy Security Improvements, the new energy imbalance reserve product will incorporate this reliability service into the day-ahead market. We also explain and provide numerical examples of co-optimized day-ahead market clearing with energy imbalance reserve, in order to illustrate important outcomes and pricing properties.

6.1 Concept And Rationale

As noted in Section 2.6, the ISO relies upon much of the generation fleet's capabilities, above and beyond its day-ahead energy awards, to achieve a reliable next-day operating plan. Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there are sufficient (scheduled) resources to cover forecast real-time energy demand.[77] The energy supply needed to cover the system's forecast energy demand for (each hour of) the next operating day is called the system's forecast energy requirement (FER).

In recent years, the day-ahead market's cleared generation and (net) imports has [typically?] been within a few percent of the ISO's forecast of real-time load in most hours. However, even a small gap in percentage terms can amount to many hundreds of MWh (per hour) and frequently over a GWh (*see* Section 6.1.2 below). The ISO relies on resources' capabilities above their day-ahead awards to cover the forecast energy requirement, and may supplementally commit (after the day-ahead market) additional resources for this purpose.[78]

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[77] *See* Brandien Testimony at pp. 6-7, 17-18.

[78] *See* Brandien Testimony at pp. 17-21.

As discussed in Section 2.6, the day-ahead market does not presently compensate the additional resources (or resources' additional capabilities above their day-ahead energy awards) that the ISO relies upon to cover this energy gap. As highlighted in Section 2.7, this state of affairs contributes to the ISO's concerns over energy security. Specifically, and as Examples 1 and 2 in Section 2 showed, resources (or portions thereof) that do not receive a day-ahead market energy supply obligation may not find it financially prudent to make costly energy supply arrangements in advance of the operating day. This not only can result in a failure of the markets to promote cost-effective investments in energy supply arrangements, it can place the power system at heightened reliability risk.[79]

6.1.1 Integrating the Forecast Energy Requirement into the Day-Ahead Market

To address this concern, the Energy Security Improvements integrate the system's hourly forecast energy requirement into the co-optimized day-ahead energy and ancillary service market.

At a conceptual level, the idea is simple. The day-ahead market will continue to clear market participants' submitted offers to supply, and bids to buy, energy day-ahead. When the total cleared energy from the system's physical supply resources is less than that hour's forecast energy requirement, the co-optimized day-ahead market will now procure energy options from additional resources (or from resources' additional capabilities above their day-ahead energy schedules), to cover that energy gap.

The energy call options procured for this purpose will receive Day-Ahead Energy Imbalance Reserve Obligations, and be settled consistent with the standard energy option settlements described earlier, in Section 4. The total amount of energy imbalance reserve procured will be (just) sufficient to 'fill the gap' between physical supply resources' total day-ahead market energy awards and the system's forecast energy requirement.

► **Simple examples.** A few simple examples are useful to illustrate the new energy imbalance reserve product. In each case below, consider a single hour of the day-ahead market, and assume the system's forecast energy requirement is 20 GWh for the applicable hour.

a) Total cleared energy demand in the day-ahead market is 18 GWh, all of which is cleared against energy supply offers from physical resources (*e.g.,* generation and imports). The day-ahead market also clears 2 GWh of energy imbalance reserve from resources that offered energy call options.

   In this situation, the day-ahead cleared energy from physical supply resources of 18 GWh is less than the forecast energy requirement of 20 GWh. However, with the additional 2 GWh of energy imbalance reserve, the combined energy and energy imbalance reserve cover the systems' forecast energy requirement:

[79] *See* example 1-R in Section 2.2.2; *see also* Brandien Testimony at pp. 23-26.

18 GWh of energy + 2 GWh of EIR $\geq$ 20 GWh forecast energy requirement.

b) Similarly, imagine instead cleared energy in the day-ahead market is 19 GWh, all from physical supply resources, and cleared energy imbalance reserve is 1 GWh. The combined energy and energy imbalance reserve again covers the forecast energy requirement:

19 GWh of energy + 1 GWh of EIR $\geq$ 20 GWh forecast energy requirement.

What if total cleared energy from physical supply resources is greater than the forecast energy requirement? Then the day-ahead market's demand for energy imbalance reserve will be zero.

c) Suppose now that total cleared energy from physical supply resources is 21 GWh. This exceeds the forecast energy requirement of 20 GWh, so no energy imbalance reserve is needed:

21 GWh of energy + 0 GWh of EIR $\geq$ 20 GWh forecast energy requirement.

In this case (c), there is no 'energy gap' between the day-ahead market's cleared physical supplies and the system's forecast demand for energy in real-time.

Case (c) illustrates an important observation. Since energy imbalance reserve is procured from suppliers at a price, the co-optimized day-ahead market will procure it only to the extent necessary to close the energy gap to the forecast energy requirement. If sufficient energy clears economically from physical supply resources to cover the forecast energy requirement for a particular hour of the next operating day, the amount of energy imbalance reserve cleared for that hour will be zero.

► **Other energy gap factors.** In examples (a) and (b), the energy gap that is covered by energy imbalance reserve arises because the total cleared day-ahead energy demand is less than the forecast energy requirement. That is one cause of an energy gap. However, there is another mechanism by which a need for energy imbalance reserve can arise. A portion of day-ahead energy demand may clear not against supply offers from physical resources, but against "virtual" energy supply offers in the day-ahead energy market. (In the Tariff, virtual energy supply offers are called Increment Offers).

As context, virtual supply offers are financial offers in the day-ahead market that, if cleared, are closed-out at the real-time energy price; we say they are "financial" in the specific sense that a virtual supply offer is not associated with a physical resource, and therefore does not supply energy in real time. For that reason, only energy supply offers cleared in the day-ahead market from physical supply resources (*e.g.,* generation and imports) are counted toward the system's forecast energy requirement for the next operating day.

Virtual transactions have a useful role in increasing the competitiveness of the day-ahead energy market.[80] However, when virtual supply offers clear, under certain conditions they may contribute to the energy gap between the day-ahead market and the forecast energy requirement. When this occurs under the co-optimized day-ahead market design, energy imbalance reserve will fill that gap as well. Here is a simple example.

d) Total cleared energy demand in the day-ahead market is 20 GWh, matching the system's forecast energy requirement of 20 GWh. On the supply side, the day-ahead market clears 19 GWh from physical supply resources and 1 GWh from virtual supply offers. In this situation, total demand matches supply in the day-ahead market's clearing, but there is an 'energy gap' of 1 GWh between the day-ahead cleared energy from physical supply resources (at 19 GWh) and the forecast energy requirement for real-time operations (at 20 GWh).

   Now assume the day-ahead market also clears 1 GWh of energy imbalance reserve from additional supply resources that offered energy call options.

   In this situation, with the additional 1 GWh of energy imbalance reserve, the combined energy and energy imbalance reserve cover the systems' forecast energy requirement:

	19	GWh of energy from physical supply resources
+	1	GWh of EIR from physical supply resources
≥	20	GWh forecast energy requirement.

Cases (a) through (d) illustrate two situations in which the current day-ahead energy-only market may produce a gap between the total energy cleared from physical supply resources and the system's forecast energy requirement for real-time operations. One is when total day-ahead cleared energy demand is less than the forecast energy requirement. The second may occur if virtual supply offers competitively displace the clearing of physical supply resources, as occurs in case (d). In that situation, even if cleared energy demand meets or exceeds the forecast, virtual supply contributes to an energy gap if the remaining cleared supply offers (from physical resources) are less than the forecast energy requirement.[81]

The co-optimized day-ahead market is designed to address both energy gap situations, using a single new ancillary service: Day-Ahead Energy Imbalance Reserve. This is important because both situations can (and do) occur concurrently. Accounting for both situations, an analysis of data from

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[80] For a detailed discussion of virtual transaction and their role in the day-ahead market, *see* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at pp. 119-126.

[81] Cleared virtual transactions have increased steadily over the last five years; in 2018, average cleared virtual supply was 621 MWh per hour. *Id*. at p. 124.

2018 indicates that there was an energy gap between the day-ahead energy market's outcomes and the forecast energy requirement in more than 78 percent of all hours (*see* Section 6.1.2, next).[82]

► **Implications.** Before proceeding to more detailed examples, we highlight two summary points here. First, viewed from the standpoint of the broader architecture of markets and reliability, we are bringing the existing forecast energy requirement into the day-ahead market. In doing so, satisfying the forecast energy requirement will now become a market process, not an out-of-market process conducted after the day-ahead market.[83] That effort has the additional benefit of improving price formation by enabling the markets to better signal, through transparent prices, the costs incurred to achieve a reliable next-day operating plan that covers forecast real-time energy demand.

The second point is that, viewed from an economic perspective, the energy option construct is naturally suited to this purpose. As noted above, the ISO's current practices rely on resources' capabilities (that are not compensated in the day-ahead market) to help cover forecast energy demand. But, beyond the energy supply scheduled in the day-ahead market, the ISO does not compensate resources on a day-ahead timeframe for the ISO's option to call on them after the day-ahead market. The ISO effectively pays a 'price' of zero for that option in today's day-ahead market today – but that option isn't actually free. Rather, providing that option to the system is costly for generators, particularly if they must incur costs to make fuel supply arrangements in advance of the operating day to ensure they can perform.

With the energy imbalance reserve component of the Energy Security Improvements, the ISO's markets will now price properly, transparently, and competitively, this currently unpriced (indeed, currently *mis*priced) option value. And, by using the standard option-based settlement design for Day-Ahead Energy Imbalance Reserve Obligations, the new design resolves the misaligned incentive problem for these resources – providing new compensation, and incentives, to undertake stronger energy supply arrangements to ensure reliable power system operations.

6.1.2 The Day-Ahead Market's Energy Gap Is Recurring Event

In the day-ahead market today, the energy gap is a common event. However, its magnitude can vary significantly from day to day, and hour to hour. Figure 6-1 shows the energy gap between the day-ahead load forecast and the total energy cleared from all physical supply resources in the day-ahead market, for each hour of 2018.[84]

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[82] *See also* Brandien Testimony at pp. 21-22.

[83] The ISO's existing process for this purpose is described in Brandien Testimony at pp. 17-23.

[84] In these data, the load forecast is the ISO's final next-day forecast of total electricity demand for each hour of the next day for the New England Balancing Authority Area, net of distributed generation. Day-ahead cleared energy from all physical supply resources is the sum total MWh cleared in the day-ahead market for the corresponding hour from: (1) all generating assets, (2) all active Demand Response Resources, and (3) the net interchange MWh over all external interfaces scheduled in the day-ahead market from other Balancing Authorities into New England (New England is a net importer of electricity). For additional discussion, *see* Section 6.4.1.

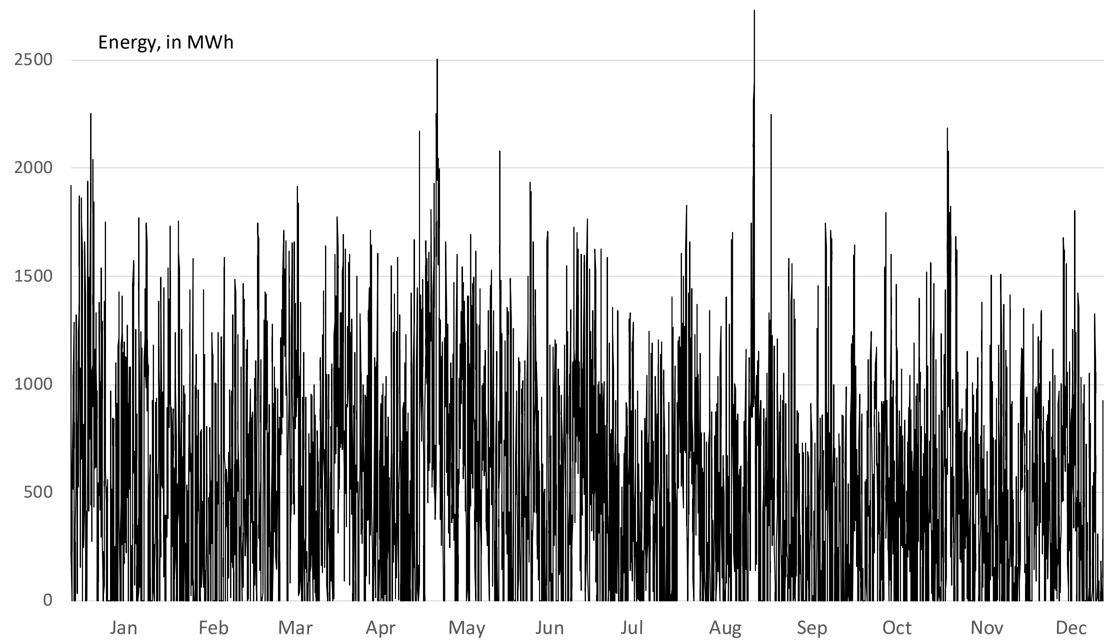

Figure 6-1. Hourly Day-Ahead Market Energy Gap, 2018

The figure shows frequent and often large energy gaps occurring throughout the course of the year. Overall, in 2018, the energy gap was zero in only 22 percent of hours, and the median hourly value was 459 MWh. It exceeded 1,000 MWh in over 25 percent of all hours (nearly 2200 hours in total in 2018). The hourly maximum of 2,728 MWh occurred on September 3, 2018, and the system experienced a real-time shortage of operating reserves for several hours that afternoon.[85]

In 2019, the energy gap pattern was qualitatively similar to that in 2018 as shown in Figure 6-1. The overall magnitudes were generally lower, with a median hourly value of 194 MWh and an energy gap of zero in a slightly larger proportion of the year, 35 percent of all hours. While the full reasons for the slightly more frequent and higher median hourly energy gaps in 2018 are not entirely clear, we do not infer a trend from these two years' of data.[86]

These recent data highlight two important observations. First, the energy gap is a recurring, persistent daily phenomenon in New England's day-ahead energy market. Second, the magnitude of the energy gap is not constant from day to day or hour to hour, and the mechanism designed to fill it must be commensurately flexible and dynamic.

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[85] For discussion of that event, *see* Brandien Testimony at pp. 22-23.

[86] In particular, the differences between 2018 and 2019 may be because 2019 was a markedly milder weather year in New England than 2018 (both summer and winter), with lower electricity demand and supply levels overall.

6.2 Day-Ahead Clearing and Pricing with Energy And Energy Imbalance Reserve: Two Supply and Demand Curves

It is important that the quantity of energy and of energy imbalance reserve cleared in the day-ahead market be jointly (*i.e.,* simultaneously) determined in a co-optimized clearing process. That is crucial to efficient pricing and to economical market outcomes. The co-optimized clearing of energy and energy imbalance reserve has important pricing and compensation implications, which merit detailed discussion next.

Fortunately, the economic logic of how the day-ahead market will clear with co-optimized energy and energy imbalance reserve can be readily visualized. We'll consider first the outcomes of the day-ahead energy-only market of today, using simple concepts of supply and demand. Then, we'll incorporate the forecast energy requirement as a 'second' demand curve into the analysis, and explore the beneficial outcomes that result.

6.2.1 Day-Ahead Market Clearing Today: Energy Only

At a broad level, day-ahead market outcomes today can be visualized as a textbook supply and demand diagram. *See* Figure 6-2. The upward-sloping line represents the market-level energy supply curve, comprised of all sellers' energy supply offers. The downward-sloping line represents the market-level energy demand curve, comprised of all participants' bids-to-buy energy day-ahead.

To simplify, in this example we will ignore the role of virtual supply in order to focus first on the situation when cleared energy demand is less than the forecast energy requirement. (We address the role of virtual supply in detail in Section 6.5). Mechanically, that means we will assume all of the energy offers in the supply curve in this figure and the next are from physical supply resources (*e.g.,* generation or imports). We also ignore here day-ahead transmission congestion and energy losses, which would unnecessarily complicate explanations; their inclusion would not change the logic and conclusions reached here.

An efficiently-organized market clears where marginal benefit equals marginal cost. In this classic supply and demand diagram, that occurs at the quantity *D* in Figure 6-2. Marginal benefit is measured by the maximum amount that buyers are willing to pay for another MWh, which is the vertical 'height' of the demand curve at quantity *D.* This is equal to the marginal supply offer price, which is the vertical 'height' of the supply curve at quantity *D.* The market clearing price is equal to the value of *DA LMP,* where marginal benefit from serving demand equals the marginal cost of serving demand.[87]

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[87] Throughout this section we assume competitive supply conditions in which sellers' offer prices reflect their marginal costs.

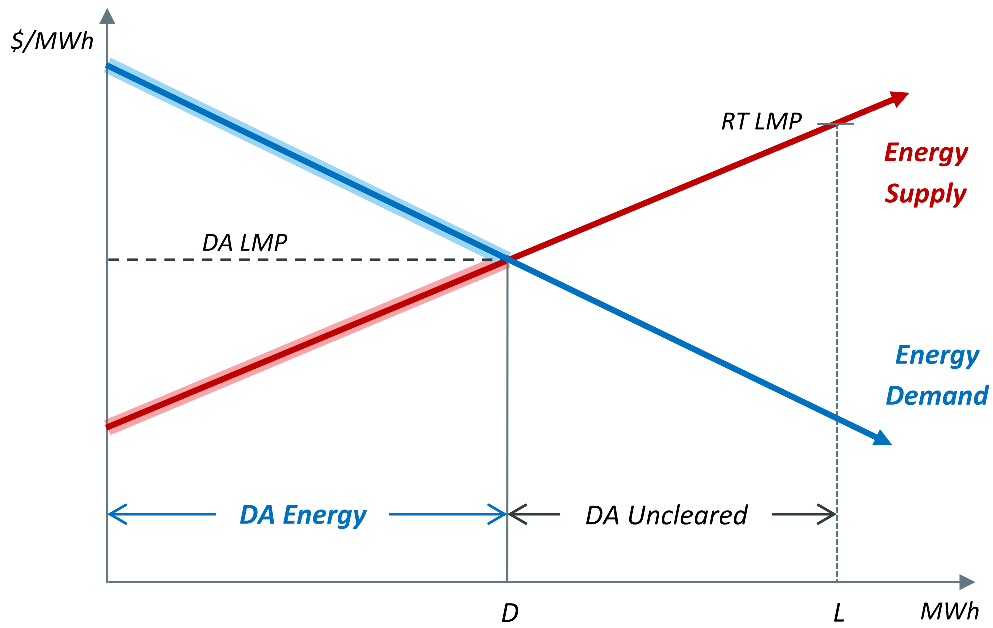

Figure 6-2. Day-Ahead Market Clearing with Energy Only

Here it is useful to note two points in relation to the energy gap concerns summarized in Section 6.1. First, in Figure 6-2 we have also added a forecast real-time load level at the quantity denoted by *L,* and assumed this is greater than total day-ahead cleared energy at *D*.[88] The difference between *L* and *D* represents the energy gap that we have been discussing. Second, the supply resources (or portions of supply resources) needed to cover that energy gap have no day-ahead market obligation. This is represented by the MWh range denoted "DA Uncleared" between *D* and *L* along the horizontal axis in Figure 6-2.

We next consider how the market outcomes change when we add to these same supply and demand curves a forecast energy requirement in order to close that energy gap.

6.2.2 Day-Ahead Market Clearing with Energy Imbalance Reserve

Conceptually, integrating the forecast energy requirement into the day-ahead market means there are, in effect, *two* demand curves. One is participants' aggregate demand curve , comprised of their submitted bids to buy energy day-ahead. The second is the forecast energy requirement. (The

[88] Because of this energy gap, the day-ahead LMP is also less than the expected real-time LMP in this example. In Figure 6-2, the expected real-time LMP is where the supply curve intersects the forecast energy demand at *L*.

second requirement is a quantity, or "vertical" demand level, and not literally a "curve"; with that proviso, we will nonetheless refer to it as a demand curve).

When there are two demand curves, there will be two cleared quantities. One quantity is for cleared energy. The second, *additional* quantity, will be energy imbalance reserve. The two, in sum, will satisfy (that is, equal or exceed) the forecast energy requirement.

Importantly, when there are two demand curves, there will also be two clearing prices. One price will reflect the bid-in demand for energy, and set the LMP. The second price will reflect the *incremental* cost of the forecast energy requirement. We call that second price, naturally, the Forecast Energy Requirement Price (abbreviated in figures as the "FERP").

► **Energy imbalance reserve supply curve**. Figure 6-3 depicts the market clearing outcomes with the forecast energy requirement, for the same participant-submitted energy supply and demand conditions shown in previous Figure 6-2.[89] As before, the forecast energy requirement is shown by the vertical line at quantity *L.*

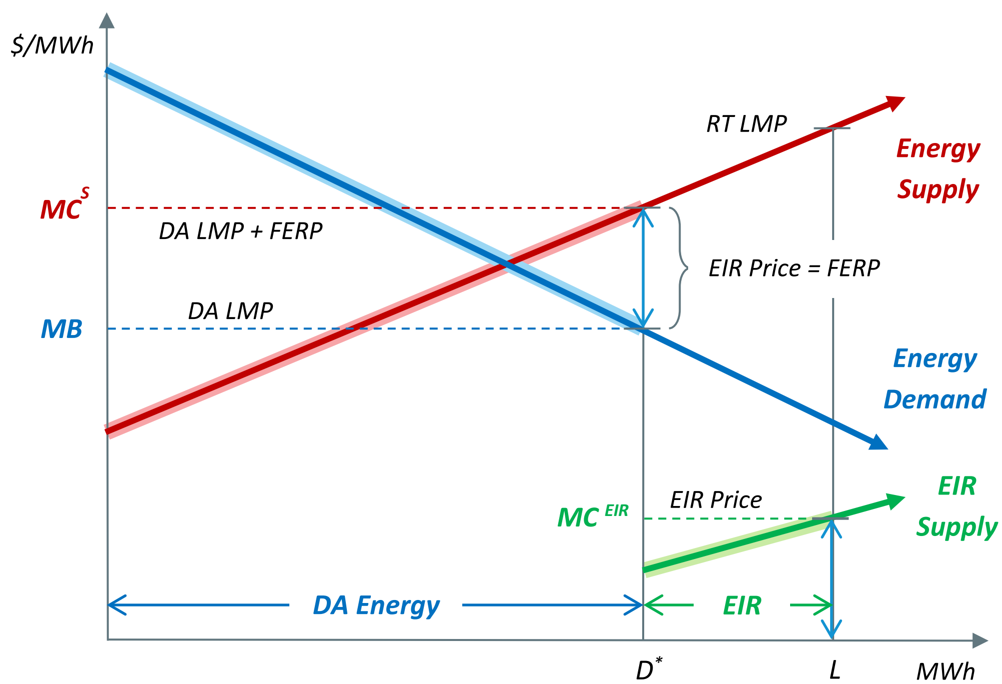

Figure 6-3. Day-Ahead Market Clearing with the Forecast Energy Requirement

[89] Specifically, Figure 6-3 similarly assumes all energy supply offers are from only physical supply resources (*e.g.,* generation or imports), not "virtual" supply, and ignores day-ahead transmission congestion and energy losses.

In Figure 6-3 we have now added a new supply curve of energy option offers that may be cleared as energy imbalance reserve. This supply curve is shown in the green in Figure 6-3, and appears below the energy supply and demand curves. In Figure 6-3, please note that the aggregate option offer supply curve is drawn starting from point *D*,* where the option supply curve indicates the offer price of the first (lowest-priced) option offer*,* and then ascends upward as we move right to the forecast energy requirement at *L.* The reason for this graphical location of the option offer supply curve will be clear momentarily.[90]

As in the simple examples in Section 6.1, a co-optimized market will clear so that the sum of physical energy supply and energy imbalance reserve satisfies the forecast energy requirement, at *L.* We'll first explain why, with the same participants' supply and demand curves for energy, the market now clears the mix of energy and energy imbalance reserve shown in Figure 6-3: quantity *D** of energy, and quantity (*L – D**) of energy imbalance reserve. This is a greater quantity of energy than clears in the market without a forecast energy requirement, which was amount *D* in Figure 6-2.

► **Clearing Quantities**. Here and generally, an efficient market clearing aligns marginal benefit and marginal cost. With two types of supply offers (for energy and for energy options), however, there are now two different marginal costs to consider.

First, there is the marginal cost of the supplier that is at the margin for energy. In Figure 6-3, this is the value (height) of the energy supply curve at the quantity *D*.* On the left axis we have labeled this cost as MC^S, for *marginal cost of energy supply*.

Second, there is the marginal cost of energy imbalance reserve, from the supplier that is at the margin for energy imbalance reserve. In Figure 6-3, this is the value (height) of the energy imbalance reserve supply curve at the quantity *L.* We have labeled this as MC^{EIR}, for *marginal cost of EIR*.

Now, the crux. What is the marginal cost to serve another increment of bid-in energy demand in the day-ahead market? With two supply curves, this involves the two products' marginal costs – or, rather, the *difference* between their marginal costs. To see this, observe that if market participants demanded (procured) an additional 1 MWh of energy, then the remaining energy gap to be procured as energy imbalance reserve would be *1 MWh less.* This is because the sum of cleared energy and cleared energy imbalance reserve must still equal the (same) forecast energy requirement, *L.*

In economic terms, this means that with a forecast energy requirement, there is a cost savings to account for when additional energy is purchased in the day-ahead market. The true marginal cost of serving one more MWh of energy demand is equal to the marginal cost of one more MWh of energy supply (from the marginal resource on the energy supply curve), *less* the cost that is saved because the market will procure one *less* MWh of energy imbalance reserve. That is, the marginal cost of

[90] A technical note: in Figure 6-3, we assume the supply curves do not 'double count' the same MW of a resource's capability in both the energy supply curve and energy imbalance reserve supply curve. This is enforced in the market clearing process, but difficult to show visually.

serving energy demand is the difference between the marginal cost of energy supply and the marginal cost of energy imbalance reserve:

(♦) *MC of serving energy demand = MC of energy supply – MC of EIR*

That relationship is key to explaining the quantity of energy and energy imbalance reserve that the market will clear. As always, an efficient market will clear where the marginal benefit equals the marginal cost of serving energy demand, or:

MB of serving energy demand = MC of serving energy demand

In evaluating the right-hand side of that expression, however, the market's clearing must account for both the marginal cost of energy supply as well as the (marginal) cost savings from the reduction in energy imbalance reserve, according to equation (♦).

In Figure 6-3, the quantity of energy where this occurs is at *D*.* There, the marginal benefit of energy demand is equal to the vertical 'height' of the energy demand curve at *D*.* We've labeled this value on the left axis as *MB* (for marginal benefit, naturally). The vertical distance *between* market participants' energy supply and demand curves at the market-clearing quantity, *D*,* is important: it is equal to the marginal cost of energy imbalance reserve, MC^{EIR}, that is saved by procuring the last unit of energy demanded (using again equation (♦)).[91]

Put simply, when there are two demand curves and two supply curves, the efficient market outcome is not where the supply and demand curves for energy *alone* intersect one another. Rather, the efficient market outcome must also account for the fact that clearing an additional MWh of energy *reduces* the amount of EIR that must be cleared to cover the forecast energy requirement. This trade-off between energy and energy imbalance reserve occurs whenever energy supply and bid-in energy demand intersect to the left of (that is, at a quantity below) the forecast energy requirement, which creates an energy gap for energy imbalance reserve to fill. As Figure 6-3 shows, in these conditions, the co-optimized day-ahead market will now clear a *greater* amount of energy than the energy-only day-ahead market of today – using both this additional cleared energy, as well as cleared energy imbalance reserve, to close that 'gap' and meet to the forecast energy requirement.[92]

Let's consider some broader implications of that important insight about the co-optimized day-ahead market's outcomes. We'll then explain the corresponding market prices.

► **Implications**. Equation (♦) has a powerful economic implication. It implies that, when the system clears energy imbalance reserve, the marginal cost of serving bid-in energy demand is *less*

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[91] In practice, these marginal costs are calculated using the supply offer prices of the marginal resources for each product (energy and for energy imbalance reserve), evaluated at the system's market-clearing quantities.

[92] Note that if energy supply from physical resources and the energy demand curve intersect to the right of (that is, at a quantity greater than) the forecast energy requirement, then the forecast energy requirement would already be met and zero energy imbalance reserve would be cleared. (*See* simple example (c) in Section 6.1).

than the marginal resource's energy supply offer. That lower marginal cost of serving energy demand means the day-ahead market will clear more energy with a forecast energy requirement, relative to today's energy-only day-ahead market.

Viewed from a broader market and reliability perspective, that fact has three benefits. First, the day-ahead market's energy schedules for supply resources will now be closer to what we expect in real-time during the next operating day. In general, the closer that the next-day operating plan matches what resources are called upon to produce during the next operating day, the more reliable the system tends to be.

Second, more *energy* from supply resources has cleared, in an amount (in MWh) equal to the horizontal distance ($D^* - D$) between Figures 6-1 and 6-2. The supply resources in that range of the supply curve (that is, between D and D^*) now clear energy in the day-ahead market, can expect to operate the next day, and will receive day-ahead compensation with which to arrange fuel in advance of the operating day.

Third, the combined total energy and energy imbalance reserve that is cleared (in MWh) in the co-optimized day-ahead market is sufficient to satisfy the forecast energy requirement. The resources that now cover the 'gap' between cleared energy and the forecast energy requirement have a Day-Ahead Energy Imbalance Reserve Obligation, consistent with the energy option settlement design. For all of the reasons explained in Sections 4 and 5, those resources now have stronger incentives to arrange fuel to ensure they can operate the next day.

In sum, by bringing the forecast energy requirement into the day-ahead market clearing process, the energy supply and energy imbalance reserve obligations now cover the forecast energy requirement. The system achieves a next-day operating plan that satisfies the forecast energy requirement through the day-ahead market alone – not through an unpriced, "out of market" process after the day-ahead energy market is conducted. And, most importantly, we will now compensate resources – both those that provide energy and that provide energy imbalance reserve – through transparent, competitively-determined market prices that reflect the cost of satisfying the forecast energy requirement for the next operating day.

In doing so, the market will compensate resource owners for the energy imbalance reserve capabilities that previously filled this energy gap but were not compensated day-ahead. They will be compensated for their intrinsic *option value* – that is, the value of the ISO's ability to call upon their energy during the operating day to meet real-time demand. And, since that option value compensation comes with proper energy call option settlements, it resolves the fundamental misaligned incentives problem for those resources.

6.2.3 Day-Ahead Clearing Prices

We now consider the day-ahead market's pricing with a forecast energy requirement and energy imbalance reserve, and who gets paid what. First, we'll explain the mechanics of the clearing prices shown in Figure 6-3. Then we'll consider more closely why these are the economically-appropriate market price signals, and assess their implications.

As the previous discussion indicated, market prices with a forecast energy requirement and energy imbalance reserve reflect marginal-cost pricing principles. The pricing consideration to account for is the presence of two demand curves and two supply curves.

With two demand curves and two supply curves, there will be two distinct market clearing prices. Both prices reflect marginal costs. The market clearing price for energy reflects the marginal cost to serve energy demand. That determines the day-ahead LMP. The second price reflects the *incremental* cost of the forecast energy requirement. That determines the Forecast Energy Requirement Price.

► **The day-ahead LMP.** The economic logic of the day-ahead LMP is based on the same marginal cost considerations that determine the market-clearing quantities. As noted earlier, if market participants demanded (procured) an additional 1 MWh of energy, then the remaining energy 'gap' to be procured as energy imbalance reserve would be 1 MWh less. This means that the marginal cost to serve energy demand is determined by the marginal cost of the energy supplied, *less* the marginal cost saved by procuring less energy imbalance reserve (see again equation (♦) above). The marginal cost to serve energy demand determines the day-ahead LMP, so the day-ahead LMP is

$$\textit{DA LMP} \; = \; \textit{MC of energy supply} \; - \; \textit{MC of EIR}$$

whenever the market clears energy imbalance reserve.[93] In Figure 6-3, the day-ahead LMP is where the demand curve for energy reaches the market clearing quantity for energy at *D**. This price is labeled *DA LMP* in the graph.

From an economic perspective, the day-ahead LMP represents the marginal benefit of energy to buyers (denoted *MB* on the left-axis in Figure 6-3). This is the economically-correct price signal to demand – it ensures that all cleared demand bids for energy are willing to pay the day-ahead LMP for energy, and that demand bids not cleared for energy are not willing to pay that price. Equally importantly, it enables the LMP for energy in the day-ahead market to properly signal the system's marginal cost of serving that demand. It does so by accounting for both the marginal cost of energy supply (as does the LMP today), and now accounting for the concurrent cost reduction in energy imbalance reserve to satisfy the forecast energy requirement.

Two additional observations merit note. First, if there is transmission congestion in the day-ahead market, then the marginal cost to serve another increment of energy demand will vary by location, and therefore so will the day-ahead LMPs. The marginal cost of energy imbalance reserve does not vary by location, as that is a system-level product with the same marginal cost (and the same energy imbalance reserve price) system-wide.[94]

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[93] This pricing logic applies when there is some energy imbalance reserve to be "saved" by clearing more energy; that is, it holds when the market clears a positive quantity of energy imbalance reserve (in MWh).

[94] In practice, the ISO calculates day-ahead LMPs based on the shadow price of the energy supply-equals-demand constraint at the cleared quantity of energy *D** (*see* the market clearing requirement expression in Section 6.4.1 below.) This enables the prices to account for energy losses, transmission limits, and additional reserve constraints (discussed in

Second, in the analysis so far and as depicted in Figure 6-3, we have assumed that participants' energy supply and demand curves intersect to the left of (that is, at a quantity less than) the forecast energy requirement. However, sometimes the market clears more energy from physical supply resources than the forecast energy requirement.[95] In such cases, from an economic perspective, the intersection of participants' demand curve and the supply curve of energy (from physical resources) would be to the right of (that is, at a quantity strictly greater than) the forecast energy requirement. When that occurs in the co-optimized day-ahead market, pricing simplifies: the day-ahead LMP would be set where participants' energy supply and demand intersect, as occurs today. The quantity of energy imbalance reserve cleared would be zero, as would be the price of energy imbalance reserve, as the forecast energy requirement is already satisfied without it.

► **The forecast energy requirement price and the energy imbalance reserve price.** As noted above, with two demand curves and two supply curves, there will be two distinct market clearing prices (with an emphasis on 'distinct'). The day-ahead LMP reflects the marginal cost to serve energy demand. Similarly, the Forecast Energy Requirement Price reflects the marginal cost to satisfy the forecast energy requirement. The third price concept we will explain, the energy imbalance reserve price, is equal to the Forecast Energy Requirement Price and is not a separate settlement rate.

First, consider the Forecast Energy Requirement Price. Following marginal pricing principles, this price is the marginal cost to satisfy an increase in the forecast energy requirement (that is, an incremental MWh above the quantity *L* in Figure 6-3). Since another increment of energy imbalance reserve can (always) be used to satisfy an increase in the forecast energy requirement, this marginal cost must equal the marginal cost of energy imbalance reserve. Thus, in Figure 6-3 and more generally, the Forecast Energy Requirement Price is equal to the energy imbalance reserve price.

Next, following the same marginal pricing principles, the energy imbalance reserve price is determined by its marginal cost at the market-clearing quantity of energy imbalance reserve. In Figure 6-3, the market-clearing quantity of energy imbalance reserve is ($L – D^*$). (Recall that in Figure 6-3, the supply curve for energy imbalance reserve is shown starting from D^*.) The energy imbalance reserve price is set where the supply curve of energy options cleared for energy imbalance reserve reaches the market clearing quantity, ($L – D^*$). This is labeled the *EIR Price* in Figure 6-3, and is equivalent to MC^{EIR}.

Note that since the Forecast Energy Requirement Price and the energy imbalance reserve price are equal (here and always), they do not represent distinct payment rates – they have the same numerical value. We use both terms for expositional purposes, here and in the Tariff, because they are paid to different cleared quantities and products (the Forecast Energy Requirement Price is paid to cleared energy supply, while the energy imbalance reserve price is paid to cleared energy

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later sections) that for simplicity we have omitted from Figures 6-2 and 6-3. Those technical calculation methods reflect the economic logic here.

[95] This occurred in 22 percent of all hours in 2018, and in 35 percent of all hours in 2019. *See* Section 6.1.2.

imbalance reserve); the terminology helps to keep clear which resources receive which payments in the mechanics of settlement charges and credits (more about which below).

Crucially, the sum of the day-ahead LMP and the Forecast Energy Requirement Price is equal to the marginal cost of energy supply. In Figure 6-3, the Forecast Energy Requirement Price is labeled *FERP* and is the vertical distance *between* the day-ahead LMP and the energy supply curve (*i.e.,* the marginal cost of energy supply) at the market-clearing quantity of energy *D**. Stated as a formula:

MC of energy supply = DA LMP + FERP.

In this way, the co-optimized market with energy and energy imbalance reserve now delineates – that is, it separately prices – the system's marginal cost of energy supply into two distinct price signals: the marginal cost of serving day-ahead energy demand (the day-ahead LMP), and the *additional* marginal cost to satisfy the forecast energy requirement (the Forecast Energy Requirement Price, *FERP*).

Importantly, and as discussed in detail next, energy suppliers will continue to be compensated based on the marginal cost of energy supply. Specifically, in today's energy-only day-ahead market, sellers' payment rate for energy reflects the system's marginal cost of energy supply (*see* Figure 6-2). Similarly, in the co-optimized market, sellers' payment rate for energy will also reflect the marginal cost of energy supply (*see* Figure 6-3). The numerical value of that payment rate will now have two components: the day-ahead LMP *and* the forecast energy requirement price. Critically, however, the fundamental economic logic of compensating energy suppliers based on the marginal cost of energy supply has not changed at all.[96]

► **Who gets paid what?** These market prices determine the payment rates applicable for energy and energy imbalance reserve in the co-optimized day-ahead energy market. We summarize the payments here, and then explain why they provide the economically appropriate compensation levels next.

- *First*, each MWh of energy demand that is cleared in the day-ahead market pays its day-ahead LMP. In this way, buyers' payment rate for energy reflects both the marginal benefit of energy, and the system's marginal cost of serving energy demand.

- *Second*, each MWh of physical energy supply that is cleared in the day-ahead market is paid the *sum* of its day-ahead LMP and the Forecast Energy Requirement Price.[97] In this way, the rate that sellers are paid for energy will continue reflect the marginal cost of energy supply, as it does today.

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[96] A caveat: though these pricing concepts apply similarly to "virtual" supply ("Increment") offers in the day-ahead energy market, the exact formulas do not. *See* Section 6.5

[97] A virtual supply (or "Increment") offer that clears in the day-ahead market will be paid the day-ahead LMP as is the case today, but is not paid the Forecast Energy Requirement Price because it has no physical energy supply to contribute to the forecast energy requirement for the next operating day. For details, *see* Section 6.5.

- *Third,* each MWh of energy call options that is cleared in the day-ahead market as energy imbalance reserve is paid the energy imbalance reserve price (which, again, is equal to the Forecast Energy Requirement Price). In this way, sellers' payment rate for energy imbalance reserve will reflect the marginal cost of its supply.

These pricing and compensation rules produce the economically appropriate price signals and payment rates, as discussed presently.

Last, the costs of satisfying the forecast energy requirement must be allocated. The cost of the Forecast Energy Requirement Price paid to energy suppliers in the day-ahead market is allocated (primarily) to real-time energy demand, on the beneficiary-pays principle. The cost of day-ahead energy imbalance reserve price paid to suppliers is allocated (primarily) to the market participants whose real-time deviations from their day-ahead energy schedules are covered by energy imbalance reserve, on cost-causation principles. We discuss these cost-allocation rules, and their rationale, in detail in Section 6.6.

► **The co-optimized day-ahead market produces economically appropriate prices and payments.** When there are multiple products in a market, there are three economic pricing principles that come into play. It is useful to summarize each of these principles, and how they are satisfied by the co-optimized day-ahead market's prices and payment rates.

The marginal-cost pricing principle. The day-ahead market's prices and payments all reflect the principle of marginal-cost pricing in efficient markets. As explained above, energy supply is compensated based on the marginal cost of energy supply; energy demand is charged based on the marginal cost of serving energy demand; and energy imbalance reserve supply is compensated based on the marginal cost of energy imbalance reserve.

***The participation payment principle*.** This principle guides compensation in a multi-product market when a participant's single offer satisfies multiple market demands or requirements. It provides that, in an efficient market, an offer that participates in satisfying multiple requirements should be paid the price associated with *each* requirement. In this way, the participating offer is compensated for the value it provides, at the margin, by avoiding clearing (more costly) separate offers for each requirement.

In the co-optimized day-ahead market, cleared energy offers from physical supply resources (*e.g.,* generation and imports) participate in satisfying *two* day-ahead market requirements: (1) the market-clearing requirement of participants' bid-in energy demand; and (2) the system's forecast energy requirement. Therefore, those energy supply offers are paid both the day-ahead LMP (for 1) *and* the Forecast Energy Requirement Price (for 2). Stated differently, *without* that energy offer in the day-ahead market, the system would have incurred *both* costs to replace it: the day-ahead LMP *and* the Forecast Energy Requirement Price.

In contrast, an energy call option offer cleared for energy imbalance reserve participates in satisfying only the forecast energy requirement; it does not participate in satisfying the market-clearing requirement of participants' bid-in energy demand. Accordingly, it is paid only the Forecast Energy Requirement Price (which, as noted, is equal to the energy imbalance reserve price).

***The substitution principle*.** In an efficient market, two goods that are perfect substitutes (for satisfying a demand or requirement) must be paid the same price for it. Being perfect substitutes, they are identically situated to the purpose for which the price applies, so discriminatory rates cannot be economically justified.

In the co-optimized day-ahead market, physical supply resources' cleared energy and cleared energy imbalance reserve are perfect substitutes *for satisfying the forecast energy requirement.* Clearing another MWh of one means the market clears a MWh less of the other, in a perfect 1-to-1 ratio. To satisfy the substitution principle, each MWh of their cleared energy and energy imbalance reserve must be paid the same Forecast Energy Requirement Price. The co-optimized day-ahead market achieves this because the Forecast Energy Requirement Price is equal to the energy imbalance reserve price.

Note that cleared energy supply and energy imbalance reserve are *not* substitutes for satisfying market participants' day-ahead market energy demand. That demand is for day-ahead forward sales of energy, and energy imbalance reserve is not a forward sale of energy. Thus, cleared energy supply is paid the day-ahead LMP for serving that demand (in addition to the forecast energy requirement price), but energy imbalance reserve is not paid the day-ahead LMP.

► **Implications.** Viewed from a broader market and reliability perspective, these properties of the co-optimized day-ahead market have three important implications.

First, incorporating the forecast energy requirement into the day-ahead market means that physical supply resources will (typically) receive greater total day-ahead market compensation, relative to the current energy-only day-ahead market design. This is because (1) the day-ahead market will tend to clear more *energy* with the addition of the forecast energy requirement, as explained in Section 6.2.2; and (2) the *total* day-ahead price paid to supply resources – that is, the sum of the day-ahead LMP and the Forecast Energy Requirement Price – is greater than the day-ahead LMP alone in an energy-only day-ahead market design (compare Figures 6-2 and 6-3).[98] In simple terms, the day-ahead market will now clear a quantity of energy farther 'up' the energy supply curve – and with energy imbalance reserve will now close the gap as required for a reliable next-day operating plan.

Second, all of the prices and compensation rates in this day-ahead co-optimized market design are economically appropriate, and are based on sound economic principles applicable to markets when there are multiple products. In simple terms, the day-ahead market will better signal, through transparent and competitive market prices, the costs of ensuring that the forecast energy requirement of a reliable next-day operating plan is satisfied. The forecast energy requirement is now a transparently priced, 'in-market' reliability requirement, and no longer an opaque, unpriced

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[98] This observation is consistent with the findings of the Impact Assessment. For the central cases evaluated, the day-ahead LMPs are slightly lower under the Energy Security Improvements cases than under the current market rules, but that change is much smaller than the larger offsetting size of the forecast energy requirement price. *See* Impact Assessment at p. 48 (Table 8).

'out-of-market' reliability requirement enforced after the day-ahead market is conducted.[99] In doing so, it advances the Commission-approved corporate mission of the ISO to "provide an opportunity for a participant to receive compensation *through the market* for a service it provides in a manner consistent with proper standards of reliability."[100]

Third, the resources that cover the gap between the forecast energy requirement and the energy cleared from physical supply resources will now have a Day-Ahead Energy Imbalance Reserve Obligation, consistent with the energy option settlement design. Their day-ahead compensation, and financial consequence for non-performance under the energy option settlements, addresses the misaligned incentives problem that exists for these resources today. Thus, for all of the reasons detailed in Sections 4 and 5, those resources will have stronger incentives under the Energy Security Improvements to arrange fuel to ensure they can reliably operate the next day.

6.2.4 Frequently Asked Questions

During the stakeholder review process over the past year, a number of questions commonly arose concerning the co-optimized day-ahead market's pricing and payments. For the Commission's benefit, we address many of these frequently asked questions and answers here.

1. **Q:** *Why is it appropriate for all generation that clears energy in the day-ahead market to be paid the Forecast Energy Requirement Price? Why do inframarginal supply resources (such as nuclear and run-of-river hydroelectric) need any new market incentives for fuel security?*

   A: The concept underlying uniform, market-clearing prices is that each seller is paid the same rate for contributing the same service. From an economic perspective, this is desirable because each seller's contribution avoids the same cost – the cost to procure from another (extra-marginal) seller with a higher offer price.

   In this way, each inframarginal resource that sells energy in the day-ahead energy market – assuming both nuclear and hydroelectric resources are such – provides the same valuable contribution to the forecast energy requirement. Their supply avoids the need to procure additional energy, at the margin, from a more costly resource to meet that requirement. If the energy procured from inframarginal resources defers the need to procure additional day-ahead energy from a more costly supplier that would have to make expensive fuel arrangements, then the inframarginal resources should be properly compensated for the value they provide in avoiding such higher-cost outcomes – *i.e.,* they should be paid the uniform, market-clearing Forecast Energy Requirement Price.

2. **Q:** *Can the Forecast Energy Requirement Price be put 'into' the LMP, like the congestion and the energy-loss components of the day-ahead LMP?*

[99] *See* Brandien Testimony at pp. 19-21.

[100] Tariff Section I.1.3(b) (emphasis added).

A. Including the Forecast Energy Requirement Price into the day-ahead LMP would result in the wrong price signal to demand (that is, to buyers) participating in the day-ahead energy market. Each additional MWh of energy procured in the day-ahead market has a cost, based in part on the marginal energy supply offer that would be cleared to satisfy it; but the additional MWh of energy procured also *saves* the system one MWh of energy imbalance reserve, reducing the cost by the energy imbalance reserve price.

In short, if the Forecast Energy Requirement Price was incorporated 'into' the day-ahead LMP, then buyers in the wholesale market would face a price signal for day-ahead energy purchases that ignores this cost saving benefit, and that therefore exceeds the system's proper marginal cost to serve them. That inefficiently high price signal to demand would discourage demand participation in the day-ahead market and result in inefficiently low total energy clearing in the day-ahead market – *worsening* the day-ahead market's longstanding energy gap problem, not solving it.

3. Q: *Is that why the cost allocation for the Forecast Energy Requirement Price must be allocated to real-time demand (load), rather than day-ahead cleared demand?*

A: Yes, exactly. If the cost of the payments made to day-ahead energy suppliers at the Forecast Energy Requirement Price were allocated to day-ahead cleared demand, the effective price of energy to buyers in the day-ahead market would be the same as if the Forecast Energy Requirement Price was incorporated 'into' the day-ahead LMP. The perverse consequences of that incorrect price signal are the same as noted in the answer to Question 2.

4. Q: *Does the Forecast Energy Requirement Price constitute a "double-payment" for energy supply resources?*

A: No. The sum of the day-ahead LMP and the Forecast Energy Requirement Price is the marginal cost of energy supply in the day-ahead market. That marginal-cost based pricing logic is the same economic rationale for suppliers' energy payment rate in the day-ahead energy market today. With co-optimized day-ahead energy and energy imbalance reserve, that total payment rate is comprised of two transparent, uniform prices: one portion of the total payment rate is the marginal cost of serving participants' day-ahead energy demand, and the other portion is the *incremental* marginal cost of the forecast energy requirement. Those are different things, not a "double-payment" for the same thing.

5. Q: *Is the Forecast Energy Requirement Price another form of uplift?*

A. No. In the Tariff, "uplift" is called Net Commitment Period Compensation (NCPC). NCPC is a resource-specific, discriminatory payment intended to ensure minimum cost recovery when the ISO accepts a resource's offer at a market price below the resource's costs.

The Forecast Energy Requirement Price is distinct from, and not a form of, NCPC. First, the Forecast Energy Requirement Price represents the marginal cost of satisfying a market-wide purchase requirement. Second, it is a uniform, transparent price paid to all resources that contribute to satisfying this requirement. And third, it is not resource-specific, and it is not designed to provide energy offer cost recovery if the ISO accepts a resource's offer at a market price below the resource's costs.

6. Q: *With the Forecast Energy Requirement Price paid to day-ahead energy suppliers, but not charged to buyers, there will be a settlement imbalance between day-ahead market's energy credits and charges, right? Does such an imbalance exist in today's day-ahead market?*

A: Yes. Today, the energy-only day-ahead market's total credits to sellers and charges to buyers do not balance. One reason is congestion pricing. That (typically) results in the total payments by demand, at their LMPs, exceeding the total payments to suppliers, whenever the day-ahead market solution is constrained by transmission. That settlement imbalance is allocated through a separate mechanism outside the day-ahead market (namely, the existing Financial Transmission Rights mechanism). A second reason is marginal loss pricing, which again results in total payments by demand being different from total payments to suppliers. Those settlement imbalances have their own allocation mechanism (namely, the Marginal Loss Revenue Fund mechanism).

The payments to supply resources at the Forecast Energy Requirement Price also create a settlement imbalance in the day-ahead market. But clearly such day-ahead market settlement imbalances are neither new or novel; they simply require a cost-allocation method outside the day-ahead market that appropriately reflects cost-allocation principles. In this case, the cost of satisfying the forecast energy requirement is allocated (primarily) to the system's real-time load, on beneficiary-pays principles. We address that in greater detail in Section 6.6 below.

7. Q: *Do buyers now have any form of "price protection" against the real-time price, if they do not purchase energy day-ahead?*

A: In a sense, yes. There are two useful perspectives on this question. First, the buyers who are allocated the costs of day-ahead energy imbalance reserve are paying for the right, but not the obligation, to "show up" in real-time and know that there are physical supply resources scheduled to cover their real-time demand (up to a limit, that is – the amount of energy call options cleared in the day-ahead market). And yes, they are 'hedged' at the energy call option strike price for their real-time price exposure (again, up to that limit). They pay for that hedge, up front, in the form of the energy imbalance reserve price, which is the price that the energy call option sellers are willing to accept for it.

The second perspective is that wholesale buyers have always been afforded that right, but have simply not been charged for it. This is because, today, the ISO nonetheless ensures, after the day-ahead market is conducted, that there are sufficient resources to satisfy the forecast energy requirement. So the main difference is simply that the real cost of this (previously unpriced) option to "show up" in real-time will be made clear to the market. Specifically, the day-ahead market will transparently price and compensate suppliers for providing this option, and will allocate its costs to wholesale market participants that avail themselves of it (*see* Section 6.6.4).

8. **Q:** *In Figure 6-1, the day-ahead LMP is less than the real-time LMP will be, assuming the load forecast is accurate. Why doesn't virtual demand, and demand bidding generally, close the 'energy gap' between the total energy cleared in the day-ahead market and the forecast energy requirement?*

   A. There are a number possible reasons why. These include the allocation of NCPC (uplift) costs to virtual transactions that deter their market participation; potentially, the systematic under-scheduling of expected real-time demand by large wholesale market buyers (which may reduce the day-ahead market clearing price); and the fact that price convergence of the day-ahead and real-time LMPs does not necessarily close the gap between cleared energy from physical supply resources and forecast energy demand. One reason for the latter is that if the market clears virtual supply offers, then there may still remain less energy cleared from physical supply resources than the total energy cleared in the day ahead market – and an energy gap to be filled in preparing a reliable next-day operating plan (*see, e.g.,* case (d) in Section 6.1.1).

   It is difficult to know for certain how much each of these possible factors contributes to the energy gap, and why demand behavior (whether virtual or otherwise) does not consistently close it. Empirically, there is an energy gap between the total energy cleared from physical supply resources in the day-ahead market and the forecast energy requirement (*see* Section 6.1.2).

9. **Q:** *Is energy imbalance reserve intended to serve as a surrogate for (insufficient) virtual transaction participation in the markets?*

   A: No. Energy imbalance reserve, and incorporating the forecast energy requirement in the day-ahead market, are complements to, not substitutes for, virtual transactions in the day-ahead market. In fact, as we will see in later examples, virtual transactions can play a valuable role in facilitating efficient day-ahead market pricing in this co-optimized day-ahead market design (*see* Section 7.7.2).

   Energy imbalance reserve has a much simpler intended purpose: to ensure that the next day operating plan has sufficient physical resources that the ISO can call on to cover the forecast energy requirement; and to ensure that, consistent with sound market design, the costs of that reliability requirement are transparently and competitively priced in the markets. By doing so, the design provides stronger incentives for resources to arrange energy supplies in advance of the operating day, helping to better address the region's energy security concerns.

6.2.5 Further Observations: Demand Behavior and Opportunity Costs

In this section, we note several additional observations and properties of the co-optimized day-ahead market with energy and energy imbalance reserve. These concern equilibrium behavior and day-ahead demand dynamics, and the impact of opportunity costs on prices. We offer these observations to provide a more complete understanding of these aspects of the new market design.

► **Equilibrium behavior.** The analysis surrounding Figures 6-2 and 6-3 above illustrates the mechanics and interpretation of market clearing and pricing. It takes the existing supply and demand curves for energy as given (that is, the same) before and after the introduction of co-optimized market clearing. However, in markets, participants react to changing conditions.

In comparing Figures 6-2 and 6-3, note that the day-ahead LMP paid by buyers, *in these examples,* decreases because clearing day-ahead energy farther 'down' the market's energy demand curve provides a cost savings by reducing how much energy imbalance reserve must be procured. That is the economically correct outcome if the market participants' bids to buy energy day-ahead do not change.

However, in practice, we should expect buyers to react to the lower day-ahead LMP by increasing the quantities they are willing to purchase in the day-ahead market. That response by market-level day-ahead energy demand will tend to raise the day-ahead LMP (bringing it closer to its value in real-time).[101]

We highlight this demand-side market response for two reasons. First, while the prior analysis (again, taking supply and demand curves as given) suggests that the day-ahead LMP will be lower under the new design, buyers' economic incentives suggest otherwise. Accounting for the economic incentives of markets to react to these price signals, it is reasonable to expect the average difference between day-ahead and real-time LMPs may not differ appreciably from the current market design.

Second, this response by day-ahead demand will tend to diminish the amount of energy imbalance reserve that is procured in the co-optimized day-ahead market. In fact, it is possible that on many days the energy imbalance reserve cleared may be zero. [102] That, however, should not be interpreted to indicate energy imbalance reserve is unnecessary – rather, that outcome is may commonly occur *because* we have incorporated and now priced the forecast energy requirement within the day-ahead market design.

► **Opportunity costs and pricing outcomes**. In the examples in this section (including those in Section 6.3 below), there is a single day-ahead ancillary service product: energy imbalance reserve. Because there is only one ancillary service product, suppliers have no opportunity costs in providing it, relative to other ancillary services. In actuality, however, the Energy Security Improvements include other day-ahead ancillary service products as well. Because of this, providing one ancillary service will, for the marginal seller, tend to come at an opportunity cost of not selling another service (if another ancillary service has a higher clearing price).

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[101] On an average annual basis, the difference between day-ahead and real-time LMPs in New England is small. In 2018, the average Hub price was $44.13/MWh in the day-ahead market and $43.54/MWh in the real-time market. *See* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at p. 54.

[102] This observation is consistent with the Impact Assessment's results. For the central cases studied, it finds that because of the substitution of energy for reserves, in the majority of all hours the cleared energy imbalance reserve is zero. *See* Impact Assessment at p. 50 (Table 10 and discussion thereof).

These product pricing interactions are important, in practice. In particular, inter-product opportunity costs can, and in many cases will, result in a higher day-ahead LMP, a higher forecast energy requirement price, or both, if there is an opportunity cost of not selling energy when cleared to provide another ancillary service (that is, other than energy imbalance reserve). For that reason, we will provide examples to illustrate these product pricing interactions after we introduce the additional ancillary services (generation contingency reserve and replacement energy reserve) in Section 7.

6.3 Example 3: Clearing and Pricing Mechanics with the FER

To illustrate the pricing and clearing concepts of the prior section, we next provide a pair of simple numerical examples. The main points of these examples are to show how the day-ahead market will tend to clear closer to the forecast energy requirement with energy imbalance reserve, and to show how the forecast energy requirement price is determined.

6.3.1 Example 3-A: Market Clearing without the Forecast Energy Requirement

We first consider an example of day-ahead market clearing with energy only, without the forecast energy requirement. From this, we will then examine how the market outcomes change with energy and energy imbalance reserve co-optimization.

► **Assumptions.** In this example, there are eight generators, Generator A through H. Their energy supply offer prices and quantities (*i.e.,* resource capacities) are shown in the first two numerical columns of Table 6-1. Note the generators are listed in ascending order of their energy offer price.

Below the energy supply offers in Table 6-1 are listed the bid prices and quantities of three energy demand bids. In this example and (most) others that follow, we will assume that market participants submit priced energy demand bids into the day-ahead market (rather than "fixed," or unpriced, day-ahead demand bids for energy).[103]

[103] For context, New England's day-ahead market does not clear with "fixed," or unpriced, demand bids near the margin. Approximately 1/3 of all day-ahead demand bids (by volume) are priced, and in practice the day-ahead market clears in the price-sensitive range of the aggregate demand curve. *See* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at pp. 73-75 (Figures 3-19 and 3-20). To capture this important feature of market participants' behavior, our numerical examples here assume that demand participates with priced demand bids.

Table 6-1. Assumptions and Market Outcomes for Example 3-A					
		Supply Offer Assumptions			Day-Ahead Outcomes
		Energy Supply Offers			Market Awards
		Price	Quantity		Energy
	Generator	($/MWh)	(MWh)		(MWh)
[1]	A	$0	300		300
[2]	B	$10	150		150
[3]	C	$36	150		150
[4]	D	$42	200		-
[5]	E	$60	200		-
[6]	F	$72	50		-
[7]	G	$78	50		-
[8]	H	$210	150		-
[9]	**Totals**		**1250**		**600**
		Demand Assumptions			
		Energy Demand			
		Price	Quantity		
		($/MWh)	(MWh)		
[10]	Bid 1	$55	500		500
[11]	Bid 2	$40	200		100
[12]	Bid 3	$35	100		-
[13]	**Totals**		**800**		**600**

► **Market outcomes.** With only one product – energy – the market will clear where energy supply and demand intersect. This is readily apparent in Figure 6-4, which shows the supply and demand diagram for the bids and offers listed in Table 6-1. The three demand bids form a descending stair-step demand "curve", and are drawn in purple. We show the supply offer bids from (only) generators B, C, and D, in Figure 6-4, to focus on the relevant range of the supply curve where the market clears.

Supply and demand intersect at a quantity of 600 MWh. In this example, any other outcome would not align marginal benefit and marginal cost. The market participant with marginal demand bid 2 is willing to pay at most $40/MWh, but the next MWh is offered by Generator D at a price of $42/MWh. Thus, clearing one more MWh would result in a marginal cost exceeding its marginal benefit; and clearing one MWh less than 600 would fail to procure one (last) MWh where marginal benefit (of $40/MWh) exceeds its marginal cost (that of Generator C, at $36/MWh).

The market-clearing price in this example is $40/MWh, where supply and demand intersect. Thus, the day-ahead LMP is set by demand bid #2, at its $40/MWh bid price. At this price, all buyers with cleared demand bids are willing to pay $40/MWh or more, and no uncleared demand bids are willing to pay more. Similarly, all generators with cleared supply offers are willing to accept $40/MWh or less, and no uncleared supply offers are willing to accept less.[104]

For what comes next, observe that in Figure 6-4, we have assumed a forecast energy requirement of 720 MWh. (This is shown below the horizontal axis, and labeled '$D_{forecast\ energy}$ = 720 MWh'). The 600 MWh of energy cleared in the market is well below this forecast energy requirement. Assuming (as we will for the moment) that the forecast materializes in real-time at 720 MWh, the real-time LMP will be higher than day-ahead, at $42/MWh from Generator D.

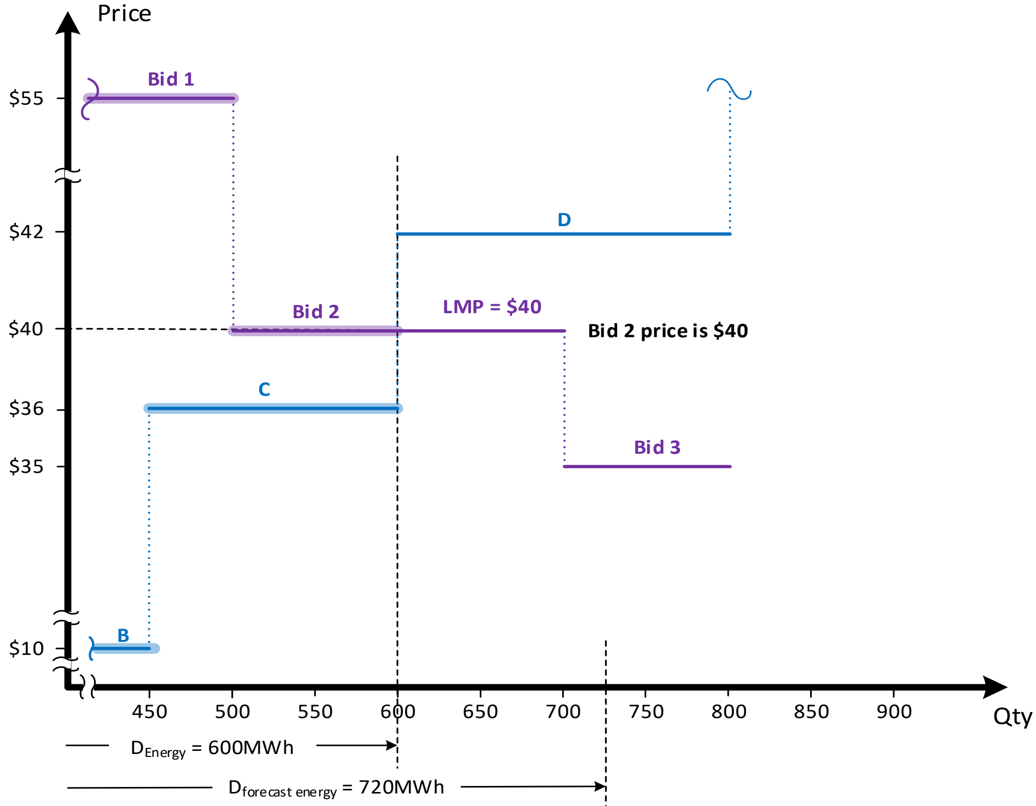

Figure 6-4. Market Outcomes for Example 3-A: No Forecast Energy Requirement

[104] In the day-ahead market, demand bids can, and do, set the market-clearing energy price. (This is common, but not always the case.) This is a consequence of economic clearing that seeks to align marginal benefit and marginal cost.

As in prior discussions, the day-ahead market has an energy gap of 120 MWh (the 720 MWh forecast less the 600 MWh that clears day-ahead). As illustrated in this example, under the current market construct Generator D has no day-ahead obligation, and market settlement in real-time if it is unable to operate the next day when called.

6.3.2 Example 3-B: Market Clearing with the Forecast Energy Requirement

We now extend this example by introducing the forecast energy requirement into the co-optimized day-ahead market with both energy and energy imbalance reserve.

The energy supply offers and demand bids are assumed to be unchanged from previous Example 3-A, and for convenience are reproduced in the first and second numerical columns of Table 6-2. Table 6-2 also lists the generators' assumed energy call option offer prices and quantities, which are submitted by Generators C through G.

Table 6-2. Assumptions and Market Outcomes for Example 3-B

		Supply Offer Assumptions				Day-Ahead Outcomes	
		Energy Supply Offers		Energy Option Offers		Market Awards	
		Price	Quantity	Price	Quantity	Energy	EIR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300			300	-
[2]	B	$10	150			150	-
[3]	C	$36	150	$2.59	100	150	-
[4]	D	$42	200	$2.59	100	100	20
[5]	E	$60	200	$5.05	90	-	-
[6]	F	$72	50	$5.54	50	-	-
[7]	G	$78	50	$5.82	50	-	-
[8]	H	$210	150			-	-
[9]	**Totals**		**1250**		**390**	**700**	**20**
		Demand Assumptions					
		Energy Demand		**Forecast Energy**			
		Price	Quantity	Quantity			
		($/MWh)	(MWh)	(MWh)			
[10]	Bid 1	$55	500			500	-
[11]	Bid 2	$40	200			200	-
[12]	Bid 3	$35	100			-	-
[13]	**Totals**		**800**	**720**		**700**	
				Day-Ahead Outcomes			
				Clearing Prices ($/MWh)			
				FERP		LMP	EIR
[14]				**$2.59**		**$39.41**	**$2.59**

The market-clearing outcomes are summarized in the last two columns of Table 6-2. Generators A through D clear energy supply offers against demand bids 1 and 2. Total day-ahead cleared energy is now 700 MWh, as shown in the second-to-last column, rows [9] and [13]. The sum of total cleared energy and energy imbalance reserve in the last two columns of row [9] is 700 MWh + 20 MWh = 720 MWh, which equals the forecast energy requirement.

► **The market-clearing outcomes align marginal benefit and marginal cost.** Let's now consider why the day-ahead market, with the same energy supply offers and demand bids as in Example 3-A, now clears 700 MWh of energy.

Figure 6-5 shows the supply and demand diagram for the assumptions and results in Table 6-2. As before, participants' demand bids for energy form a descending stair-step demand 'curve' and are indicated in purple. The supply offers of Generators B, C, and D, which span the range where the market clears, are shown in the ascending stair-step supply 'curve' in blue. The energy call option offer prices for Generator D's remaining capacity (that is, its capability not cleared as energy), and for Generator E, are shown in the orange stair-step EIR supply curve. Note that, like Figure 6-3 earlier, the EIR supply curve is drawn starting from the quantity of energy cleared in the market, here 700 MWh.

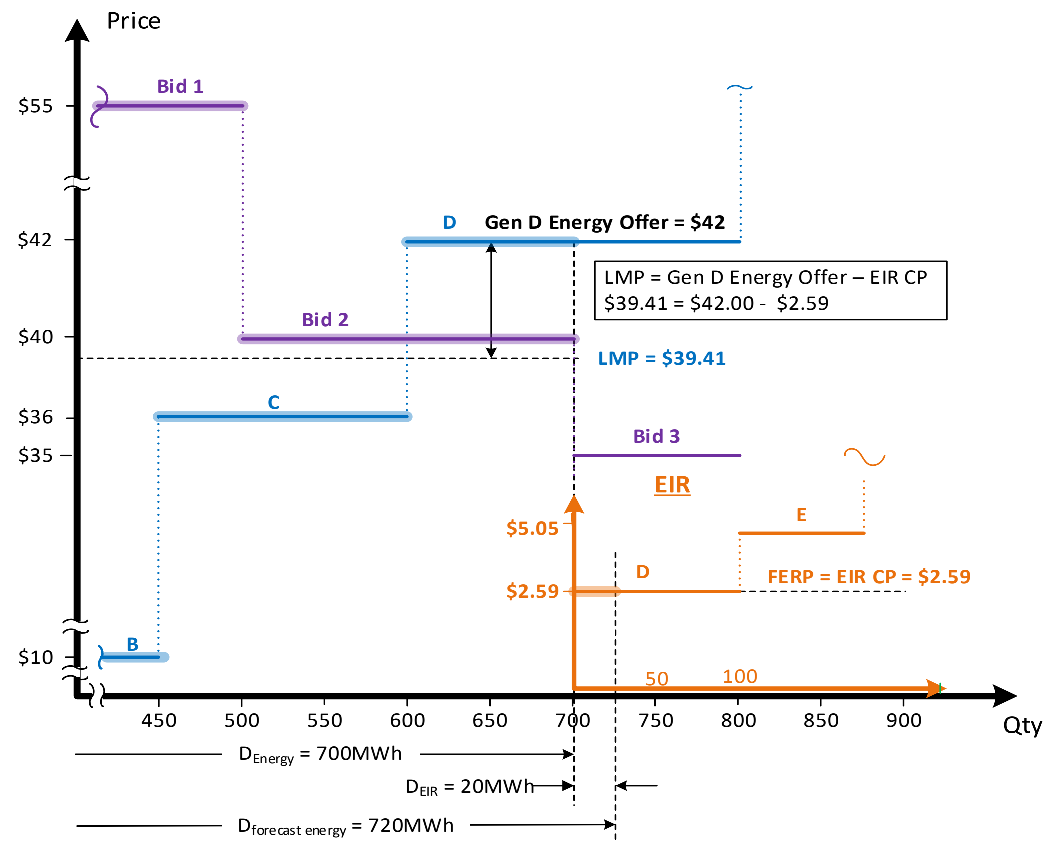

Figure 6-5. Market Outcomes for Example 3-B with the Forecast Energy Requirement

To see why the market clears 700 MWh of energy, consider the marginal benefit and marginal cost of serving demand of the last, 700th MWh. The marginal benefit is the value of demand bid 2 at that last MWh, or $40/MWh.

Now consider the marginal cost incurred by the system to serve that last MWh of energy demand. That has two pieces: the marginal cost of energy supply, *less* the marginal cost savings from one less MWh of energy imbalance reserve. The 700th MWh of energy supply comes from Generator D, at an offer price of $42/MWh. However, by clearing the last MWh of energy, the system is able to clear one less MWh of energy imbalance reserve. The marginal cost of energy imbalance reserve is $2.59/MWh, also from Generator D, and so the marginal cost savings from less energy imbalance reserve is $2.59/MWh. Putting the pieces together, for the 700th MWh of energy,

MC of serving energy demand = $42/MWh energy – $2.59/MWh EIR = $39.41/MWh.

The 700th MWh of energy therefore has greater marginal benefit, $40/MWh, than its marginal cost. Thus, the market clears (at least) 700 MWh.

Of course, it is also important to check that clearing *another,* 701st MWh of energy, would have marginal cost in excess of its marginal benefit. Here, the marginal benefit of the 701st MWh would be that of demand bid #3, which is willing to pay only up to $35/MWh. The marginal cost of serving that 701st MWh of energy is the same as before, at $39.41/MWh. Therefore, the market would *not* clear the 701st MWh, as its marginal cost ($39.41/MWh) exceeds its marginal benefit ($35/MWh).

There are two notable points of these calculations so far. First, the co-optimized market clearing process is still governed by the same properties of an efficient market – the quantities cleared align marginal benefit and marginal cost. However, the marginal cost of serving energy demand is different when the market also clears energy imbalance reserve, because additional energy supply substitutes (*i.e.,* avoids the cost of) energy imbalance reserve at the margin. We highlight this logic because this economic balancing of marginal benefit and marginal cost in a co-optimized day-ahead market illustrates what is meant by when the ISO (and the Tariff) indicates that it performs an "economic commitment and dispatch" to clear the day-ahead market.[105]

Second, as noted previously in Section 6.2.2 and 6.2.5, the net impact of this property is that the market will tend to clear energy 'farther up' the energy supply curve, with higher total quantities than in the energy-only day-ahead market of today under the same conditions.

► **The market-clearing prices.** The market clearing prices are determined by the same logic. First consider the Forecast Energy Requirement Price. This is the marginal cost of an incremental change in the forecast energy requirement. If that requirement increased by one MWh, from 720 MWh to 721 MWh, the least-cost means to satisfy it would be to clear an additional (*i.e.,* 21st) MWh of energy imbalance reserve from Generator D, at a marginal offer price of $2.59. See Figure 6-5.

[105] *See, e.g.,* Tariff Sections III.1.7.6(a), III.1.10.8(a)(ii), and III.2.2.

Therefore, the Forecast Energy Requirement Price and energy imbalance reserve price are $2.59/MWh.

The day-ahead LMP calculations are summarized in Table 6-3. At the market-clearing quantity of 700 MWh, the marginal bid or offer is the offer of Generator D, at $42. However, procuring another MWh of energy from it would reduce – or "re-dispatch down" – its EIR award by 1 MWh, at a cost savings of $2.59/MWh. The marginal cost of serving energy demand is the difference, $42/MWh - $2.59/MWh = $39.41/MWh, so the day-ahead LMP is therefore $39.41. The day-ahead LMP is not set *at* any one bid's or offer's price, but by the *difference* in two marginal offer prices: One for energy, and the other for energy imbalance reserve.

Table 6-3. LMP Calculation for Example 3-B			
	Change in Total (Production) Costs for One More MWh of Energy Demand		
[1]	+ 1 MWh of energy from Generator D	$42.00	***Energy offer price of marginal Gen D***
[2]			***(results in one less MWh of EIR from Gen D)***
[3]	"Re-dispatch" EIR		
[4]	- 1 MWh of EIR from Generator D	($2.59)	***"Savings" from one less MWh of EIR from Gen D***
[5]		**$39.41**	***Marginal cost of serving energy demand (LMP)***

► **Who gets paid what.** On the demand side, the market participants with demand bids 1 and 2 are charged the day-ahead LMP of $39.41/MWh for the MWh they clear. Note that all cleared demand bids are willing to pay the day-ahead LMP or more, and that no uncleared demand bid is willing to pay more. The settlement rate of the day-ahead LMP is therefore consistent with an efficient market-clearing outcome for the demand side of the market.

On the supply side, Generators A, B, C, and D are credited the sum of the day-ahead LMP and the Forecast Energy Requirement Price for the MWh of energy they clear, or $39.41/MWh + $2.59/MWh = $42/MWh. This settlement rate is the marginal cost of energy supply, as determined by marginal Generator D's energy offer price of $42/MWh. In this way, all cleared energy supply offers are willing to accept the settlement rate of $42/MWh or less, and no uncleared energy supply offers are willing to accept less. The settlement rate of the day-ahead LMP *plus* the forecast energy requirement price is therefore consistent with market-clearing outcome for the energy supply side of the market.

In addition, Generator D is credited the energy imbalance reserve price of $2.59/MWh for each MWh of energy imbalance reserve it clears. It is willing to accept this settlement rate of $2.59/MWh, and no uncleared energy option offer is willing to accept less. The settlement rate of the energy imbalance reserve price is therefore consistent with market-clearing outcome for the energy option supply side of the market. Note further that the clearing prices settlement rates ensure that marginal Generator D is indifferent between providing energy and energy imbalance reserve.

Last, there is the cost of the Forecast Energy Requirement Price and energy imbalance reserve price to be allocated. This total cost is $2.59/MWh multiplied by the 720 MWh forecast energy requirement (with 700 MWh of that being forecast energy requirement payments to Generators A, B, C, and D for energy, and 20 MWh of that being energy imbalance reserve payments to Generator D). In this example, that cost would be allocated to real-time load (*see* Section 6.6.2). In simple terms, buyers ultimately pay the cost of operating a reliable power system, and those costs are now reflected through transparent market prices.

► **The main points.** There are two main points of Example 3-B. First, with the forecast energy requirement incorporated into the day-ahead market, an additional 120 MWh clears for energy or for energy imbalance reserve. Both obligations provide a day-ahead schedule that Generator D can expect to operate to in real-time, given the forecast energy demand. Generator D now receives day-ahead compensation for those 120 MWh to arrange energy supply in advance of the operating day.

Second, note that if Generator D did not arrange energy to operate, then it would need to 'buy out' both its 100 MWh day-ahead energy award at the real-time LMP, and its 20 MWh energy imbalance reserve award at the real-time LMP less the strike price (if positive). That would be a costly outcome. For its 100 MWh energy obligation, Generator D's replacement cost for real-time energy would be (at least) $60/MWh from Generator E (assuming Generator E was available in real-time; it could be higher still if not). Compare that to the situation in today's day-ahead energy market in Example 3-A, where Generator D did not clear in the day-ahead market – and, if it does not arrange fuel and cannot operate in real-time, it would have incurred no charges at all.

For this reason – much as illustrated for the energy option award in earlier Examples 1 and 2 in Section 5 – the co-optimized day-ahead energy and energy call option design provides much stronger incentives for the resources the ISO relies upon to arrange energy supplies in advance of the operating day.

► **Co-optimization and cost-effectiveness**. As noted at the outset of this section, in a co-optimized day-ahead market, the cleared quantities of energy and energy imbalance reserves are simultaneously determined (*i.e.,* endogenous) within the market clearing process. That is essential to produce cost-effective outcomes that reflect marginal benefits and marginal costs.

For instance, if the energy option offer prices comprising the energy imbalance reserve supply curve were significantly higher than shown in Table 6-2, the market would clear less energy imbalance reserve and more energy instead. That substitution of energy for energy imbalance reserve, within the co-optimization process, efficiently reduces the cost impact of a potential day with higher-than-normal energy option offer prices, while still satisfying the forecast energy requirement.

Similarly, if energy supply offers are higher than normal, the day-ahead market's clearing would substitute more energy imbalance reserve for energy.[106] In this way, the co-optimized day-ahead market design is structured to produce the most cost-effective scheduling of the system's resources,

[106] In this example, that would occur if Generator D's energy supply offer price exceeded $42.59/MWh, in which case the market would not clear Generator D's now expensive energy and instead purchase from it 120 MWh of less expensive energy imbalance reserve.

given their offer prices, while simultaneously satisfying both the forecast energy requirement and market participants' day-ahead bid-in energy demand.

6.4 The Forecast Energy Requirement: Details

In this section, we provide additional detail on the formulation of the forecast energy requirement that will be incorporated into the co-optimized day-ahead market clearing process with these Energy Security Improvements. This also has implications for the settlement of virtual transactions in the day-ahead market, which we explain presently. We also summarize various new tariff provisions related to the forecast energy requirement.

6.4.1 Forecast Energy Requirement Specification

The forecast energy requirement is part of the ISO's preparation of a reliable next-day operating plan and, at present, is implemented through operating procedures performed after ("outside" of) the day-ahead market.[107]

In the existing energy-only day-ahead energy market, there is a single market clearing requirement: total energy supply equals total energy demand. In incorporating the forecast energy requirement into the day-ahead market, there will be an additional, second clearing requirement for energy and energy imbalance reserve from physical supply resources. Because they are evaluated simultaneously, we summarize next the existing market-clearing requirement and the market's new forecast energy requirement.

► **The market-clearing requirement specification.** Stated in summary form, the existing day-ahead market-clearing requirement (MCR, for short) can be expressed as:[108]

(MCR) $$GEN_h + IMP_h + INC_h = DMD_h + EXP_h + DEC_h$$

The left-hand side of the equation is total cleared supply, and the right-hand side is total cleared demand. Stated more precisely, on the left-hand side GEN_h is the total MWh of all energy supply offers cleared in the day-ahead market for hour *h* from generation resources (including active demand response that is treated as "supply" in the day-ahead market). IMP_h is the total MWh of all external transaction energy imports into New England cleared (scheduled) for hour *h* in the day-ahead market. The term INC_h is the total MWh of Increment Offers (virtual supply) cleared in the day-ahead market for hour *h.*

[107] *See* System Operating Procedure RTMKTS.0050.0010 – Perform Reserve Adequacy Assessment, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf. *See also* Brandien Testimony at pp. 19-21.

[108] For simplicity, this ignores energy losses. Separate constraints (omitted here) characterize transmission limits in the market-clearing process.

On the right-hand side of the equation, DMD_h is the total MWh of all participant-submitted energy demand bids cleared in the day-ahead market for hour *h,* exclusive of exports and virtual demand bids. EXP_h is the total MWh of all external transaction energy exports from New England cleared (scheduled) for hour *h.* DEC_h is the total MWh of Decrement Bids (virtual demand) cleared in the day-ahead market for hour *h.*

The day-ahead market-clearing requirement formulation in expression (MCR) does not change with co-optimization. It will continue to ensure that the day-ahead market clears equal amounts of energy supply and demand. As explained in Sections 6.2 and 6.3, however, the total MWh of energy supply and demand that clear will change with the addition of the forecast energy requirement to the day-ahead market.

► **The forecast energy requirement specification***.* The forecast energy requirement determines the energy and energy imbalance reserve needed to cover the forecast energy demand for (each hour of) the next operating day. It is implemented as a new, additional constraint within the co-optimized day-ahead market-clearing solution.

Stated more precisely, the forecast energy requirement (FER, for short) for energy and energy imbalance reserve can be expressed as:

(FER) $$GEN_h + IMP_h + EIR_h \geq LF_h + EXP_h$$

On the left-hand side of this equation, GEN_h and IMP_h are the same total day-ahead MWh cleared for hour *h* from generation and imports that appear in equation (MCR). The new term EIR_h is the total MWh of energy imbalance reserve that the day-ahead market will now clear for hour *h* to satisfy this forecast energy requirement.

On the right-hand side of this equation, LF_h is the ISO's system-wide load forecast for hour *h* of the operating day (more about which below). EXP_h is the same total MWh of day-ahead cleared exports as in equation (MCR).

A note on terminology. Technically, the forecast energy requirement is a *constraint*, as expressed in equation (FER). When it will cause no confusion, it can be useful to also refer to the forecast energy requirement as the *value* of the load forecast, which is the term LF_h that appears on the right-hand side of equation (FER). For precision, in the Tariff we introduce the defined term Forecast Energy Requirement Demand Quantity to refer to the value of the load forecast, LF_h, that appears in equation (FER) (*see* new Tariff Section III.1.8.6).

► **Simultaneous determinations of energy and energy imbalance reserve***.* It is important to note that when the forecast energy requirement constraint is incorporated with the day-ahead market clearing process, four of the five terms in expression (FER) will be endogenously determined by the market. The only "fixed" value in that expression is the load forecast, which is determined in the ISO's load forecasting process (just) prior to the day-ahead market. All of the other components are simultaneously determined in the course of clearing equal amounts of total energy supply and demand, based on all energy supply offers, demand bids, and energy call option offers.

As a simple example, consider the numbers from Examples 3-A and 3-B in Section 6.3 above. Neither imports and exports, nor virtual transactions, were present in that example, so the terms IMP_h, EXP_h, INC_h, and DEC_h are all zero. In Example 3-A, the energy-only case, the total cleared generation (from Generators A, B, and C) is 600 MWh and total cleared demand is 600 MWh (from demand bids 1 and 2). This satisfied the market clearing requirement in equation (MCR), but left an energy gap because the forecast energy requirement was 720 MWh.

When we added the forecast energy requirement in Example 3-B, the total cleared generation is 700 MWh (from Generators A, B, C, and D), and total cleared demand is 700 MWh (from demand bid 1 and more of demand bid 2). This again satisfies the market-clearing requirement in equation (MCR). The total cleared energy imbalance reserve is 20 MWh, which when added to the total cleared generation, matches the load forecast of 720 MWh. Both equation (MCR) and equation (FER) are now satisfied by the market-clearing solution.[109]

► **Load forecast, imports, and exports**. The energy supply counted toward the forecast energy requirement is the amount that cleared day-ahead from physical supply resources. Specifically, as equation (FER) shows, the day-ahead cleared energy from physical supply resources is all of the energy cleared from generation and imports (along with active demand response treated as "supply" in the energy market, which we include by reference here as cleared generation).

On the right hand side of equation (FER), the sum of the ISO's load forecast and day-ahead cleared exports represents the total expected energy demand for hour *h* of the next operating day. Importantly, in practice, the ISO's operational next-day load forecast is an estimate of real-time load *within* the New England Balancing Area; that is, it excludes imports or exports. Thus, the exports that economically clear in the day-ahead market are explicitly added to the right-hand side of the forecast energy requirement constraint (FER) to better estimate the system's total energy demand during the next operating day. This treatment of day-ahead cleared imports and exports mirrors how the forecast energy requirement is implemented today, as an "out of market" process after the day-ahead market is conducted.

The ISO's load forecast is an estimate of each upcoming hour's real-time electrical load system-wide. It is net (the effects) of distributed generation and other generation that does not participate in the wholesale electric market, such as behind-the meter photovoltaic output. The forecast is updated (at least) twice daily, and posted publicly at 6:00 a.m. and 10:00 a.m. each day. Each forecast update produces hourly load estimates for today, for tomorrow, and for the next day.[110]

On average, the forecast for the next operating day produced (just) prior to the day-ahead market (*i.e.,* the 10:00 a.m. update) is neither too high, nor too low. In 2018, the average hourly day-ahead load forecast error was –24 MW, and in 2019 it was +12 MW. These are very small, representing

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[109] The day-ahead co-optimized market will satisfy the requirements in equations (MCR) and (FER) in addition to the requirements for the other new day-ahead ancillary services (generation contingency reserve and replacement energy reserve, discussed in subsequent sections).

[110] *See* Three-Day System Demand Forecast, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast/.

approximately one-tenth of one percent of actual (realized) load. This indicates that on average, incorporating the load forecast into the market through the forecast energy requirement will not systematically to procure too much, nor too little, energy for the New England Balancing Area for the next operating day.

Of course, on any given day actual load in real-time may be higher or lower than forecast, in part due to the inherent variability of New England's weather.[111] This uncertainty presented additional operational risks, which are also appropriately addressed with these Energy Security Improvements. We discuss how these uncertainties can be properly addressed through the market using replacement energy reserve in Section 7.

6.4.2 Tariff Provisions

In this section we describe various rules governing energy and energy imbalance reserve co-optimization, the forecast energy requirement, and the associated new Tariff provisions in this filing.

► **Key terminology.** For clarity, several new Tariff provisions use the more economically-precise term "Demand Quantity" to reference numerical values that, in more common parlance, are referred to as "requirements." Specifically:

- New Section III.1.8.6 defines the Forecast Energy Requirement Demand Quantity, which is the ISO's day-ahead load forecast for the applicable market hour. Section III.1.8.6 references existing provision Section III.1.10.1.A(h), which governs the ISO's production and provision of the system's load forecast, consistent with the foregoing discussion in Section 6.4.1. In other words, this filing does not modify the ISO's existing load forecasting process.

- New Section III.1.8.5(f) defines the new Day-Ahead Energy Imbalance Reserve Quantity. Consistent with the foregoing explanations in Sections 6.2 through 6.4 of this paper, this quantity is endogenously determined within the market; it is not a fixed value. The Tariff language is therefore formulaic, capturing equation (FER) in Section 6.4.1, above. That is, the amount of energy imbalance reserve determined within in the co-optimized market's clearing is the amount necessary to close the 'gap', if positive, between the Forecast Energy Requirement Demand Quantity (*i.e.,* the load forecast for the applicable hour) and the total cleared energy from Generator Assets, Demand Response Resources (which participate as "supply" in the energy market), and net scheduled interchange (imports minus exports).

[111] The mean absolute error of the day-ahead load forecast was just under two percent in 2018 and 2019 (as a percent of actual load); in absolute terms, this corresponds to a mean absolute error of 275 MW and 246 MW in each year, respectively.

It is through this specification of the Day-Ahead Energy Imbalance Reserve Quantity that the forecast energy requirement, as expressed in equation (FER) in Section 6.4.1 above, is incorporated into the Tariff for purposes of clearing the co-optimized day-ahead market.

► **Co-optimization-related new tariff provisions.** Consistent with the design and economic rationale for energy and energy imbalance reserve explained throughout Section 6 of this paper, various new and revised portions of Sections III.1 and III.2 of the Tariff address co-optimized clearing of the day-ahead market.

The primary day-ahead market co-optimization provisions are contained in new Section III.1.10.8(a)(ii), revising existing Section III.1.10.8(a). These revisions extend the existing energy-only day-ahead market reflected in Section III.1.10.8(a) to a day-ahead market that clears both energy and ancillary services, and incorporates the forecast energy requirement. Of note:

- *Joint optimization.* The first paragraph in new Section III.1.10.8(ii) states that the day-market will be jointly optimized (that is, co-optimized) for energy and the new Day-Ahead Ancillary Services (including, by that defined term, Day-Ahead Energy Imbalance Reserve and the other new ancillary services discussed subsequently in Section 7 of this paper).

  The joint optimization expressly performs an economic commitment and dispatch. As explained in Sections 6.2 and 6.3 of this paper, that corresponds to the economic concept of seeking to align marginal benefits and marginal costs and is consistent with economically-efficient market outcomes, per the ISO's broader mission to create and sustain markets that are economically efficient (*see* existing Tariff Section I.3.1(b)).

- *Forecast energy requirement*. The first paragraph in new Section III.1.10.8(ii) also indicates that the market clearing outcomes shall satisfy the Forecast Energy Requirement Demand Quantity. As discussed in Section 6.4.1 above, all elements of equation (FER) are endogenously determined within the co-optimized day-ahead market except for the Forecast Energy Requirement Demand Quantity, which is specified prior to the day-ahead market according to the next-day hourly load forecasts.

- *Additional clarifying language to accommodate new ancillary services.* The second paragraph in new Section III.1.10.8(ii) mirrors the existing second paragraph of Section III.1.10.8(i), and it mostly contains identical, enumerated provisions. The substantive changes between the new and the existing paragraph are: the wording in item (5) has been generalized to account for ancillary services more broadly, in order to accommodate the new ancillary services in this filing; and the wording in item (6) expressly notes that the clearing will account for resources' physical operating characteristics. As discussed in Section 4.1, and in greater detail in Section 7.2, the co-optimized market's outcomes are determined subject to resources' physical capabilities (such as their maximum output levels, ramp rates, and such).

- *Limitations*. The final portion of new Section III.1.10.8(ii) contains two technical limitations on the clearing process. The first, in enumerated item (1) in the last paragraph of Section III.1.10.8(ii), is only applicable to generation contingency reserve and replacement energy reserve. We discuss this provision in Section 7.4 of this paper, after we explain those specific new ancillary services. The second, in enumerated item (2) in the last paragraph of Section III.1.10.8(ii), is a limitation on energy imbalance reserve awards to non-fast start resources without day-ahead energy schedules. This is motivated by computational considerations, and we explain this provision and its rationale in Section 6.4.3, next.

In addition, there are general revisions acknowledging that the day-ahead market will be co-optimized in Section III.1.7.6(a), Section III.1.10.2(b), Section III.2.1, and Section III.2.2, where such were necessary for consistency with the new co-optimized clearing provisions in Section III.1.10.8.

Last, new Section III.3.2.1(a)(2)(vi) states that energy call option offers that are cleared and contribute to satisfying the Forecast Energy Requirement Demand Quantity will receive a Day-Ahead Energy Imbalance Reserve Obligation. (Note that the term “Obligations” as used in this portion of the Tariff refers to quantities for settlement, and are units of MWh, not dollars).

The language used in new Section III.3.2.1(a)(2)(vi) reflects the market design attribute that market participants’ energy call option offers are the *inputs* into the co-optimized day-ahead market clearing process, and the different ancillary service products (*i.e.,* obligations) are the *outputs* of the market clearing process (*see* Section 4.1).

► **Pricing provisions.** The pricing provisions for the new ancillary services are primarily contained in new Section III.2.6.2. Here, we summarize those provisions specifically related to incorporating energy imbalance reserve and the forecast energy requirement into the day-ahead market. (The corresponding provisions related to generation contingency reserve and replacement energy reserve are discussed separately, in Section 7.4). Specifically:

- Section III.2.6.2(a)(vii) defines the Forecast Energy Requirement Price. Consistent with the economic explanations in Section 6.2 and 6.3 of this paper, this price it is calculated as the marginal cost to satisfy the next increment of the Forecast Energy Requirement Demand Quantity. (On this, *see also* Section 6.4.3 below, under ‘Pricing Notes’).

- Section III.2.6.2(a)(vi) assigns the clearing price for energy imbalance reserve to be the Forecast Energy Requirement Price, explicitly. This is consistent with the rationales and explanations for this property in Sections 6.2 and 6.3, above.

- Section III.2.6.1 has a new addition to the existing Locational Marginal Price provisions to enable the day-ahead LMP to properly account for the impact of the (marginal) cost of energy imbalance reserve on the day-ahead LMP, as illustrated in Example 3-B above. Sections III.2.2. and III.2.2(a) also contain general revisions for the same purpose.

  Note that the revised provisions in Section III.2.6.1 are not structured specific to energy imbalance reserve, but cover all of the new Day-Ahead Ancillary Services. This is because the costs of other ancillary services, generation contingency reserve and replacement energy reserve, can also impact the calculation of the day-ahead LMP. We explain this below in Section 7 of this paper.

6.4.3 Technical Notes on Certain Tariff Provisions

In the Tariff, certain provisions are primarily technical in nature, or require technical explanations. In this section, we provide further explanation and rationale for three such provisions of the instant filing. These concern: additional clarity on the Forecast Energy Requirement Price in new Section III.2.6.2(a)(vi); a clearing limitation on energy imbalance reserve awards based on computation considerations in new Section I.10.8(a)(ii); and the Reserve Constraint Penalty Factor on the forecast energy requirement in new Section III.2.6.2(b)(vi). We address each in turn below.

► **Technical notes on the Forecast Energy Requirement Price.** In Section 6.2, we explained the key economic logic of the Forecast Energy Requirement Price using supply and demand concepts. The precise interpretation of the Forecast Energy Requirement Price as the marginal cost of satisfying the system's forecast load comes directly from equation (FER) (*see* Section 6.4.1). When equation (FER) holds with equality at the co-optimized market's solution, an incremental change in the load forecast, LF_h, will require an equal incremental change in the MWh cleared from (a combination of) the energy and energy imbalance reserve on the left-hand side of equation (FER). The change in the (dollar-denominated) day-ahead market's solution objective resulting from an incremental change in LF_h (in MWh) measures the marginal cost of satisfying the forecast energy requirement, and sets the Forecast Energy Requirement Price.[112] The new Tariff language defining the Forecast Energy Requirement Price, in Section III.2.6.2(a)(vi), is written to reflect that that price calculation logic precisely.

New Section III.2.6.2(a)(vi) also accommodates the possibility that at the co-optimized market's solution, equation (FER) may hold with *inequality* – that is, the total MWh on the left-hand side may exceed the total MWh on the right. In this case, an incremental change in the load forecast, LF_h, will not require any increase in the total MWh cleared on the left-hand side for equation (FER) to still remain satisfied. When this occurs, the co-optimization will find it most cost-effective (*i.e.,* optimal) to clear zero MWh of energy imbalance reserve. And since no increase in the total MWh of energy from generation or imports is required to satisfy an increase in the load forecast in this situation, the marginal cost of the forecast energy requirement is zero – and therefore so is the Forecast Energy Requirement Price. In other words, if the co-optimized day-ahead market economically clears sufficient generation and net imports such that equation (FER) does not bind at the market clearing solution, the Forecast Energy Requirement Price will be zero.

► **Energy Imbalance Reserve awards and energy schedules.** In new Section I.10.8(a)(ii), there is a technical provision concerning energy imbalance reserve in this section's final paragraph (which is enumerated starting with (2)). The substantive effect of this provision is that in clearing energy imbalance reserve, the co-optimized day-ahead market will only award energy imbalance reserve obligations to resources that either: (i) are also cleared for energy (using a *different* portion of their

[112] In mathematical terms, this is known as the *shadow price* of the forecast energy requirement constraint; the Forecast Energy Requirement Price is the shadow price of the forecast energy requirement constraint at the co-optimized market's dispatch solution, given the (optimized) unit commitment schedules.

resource's output range) for the same hour of the next day, or (ii) are fast-start resources (which can start in 30-minutes or less during the operating day).

Stated differently, the day-ahead market will not award energy imbalance reserve to a resource that does not have a day-ahead commitment schedule to be online for energy (which would necessarily be at its Economic Minimum output level or higher) for the same hour, *unless* the unit is a fast-start resource.

The reason for this limitation is a computational one. During the technical evaluation of the co-optimization algorithms, the ISO's technical experts determined that without this limitation, the day-ahead clearing algorithm would require a (near) doubling of the number of integer commitment variables to compute a solution. This raised concern that without this limitation, it may not be practical to optimize the market (within the timeframes necessary to administer the market), because the time required to compute a solution increase nonlinearly with integer commitment variables. With this limitation, we can use the same integer commitment variables for both energy and energy imbalance reserve, and this particular computational concern is no longer an issue.[113]

It is important to note that this limitation is not exclusionary. The co-optimized day-ahead market can clear any resource for energy in order to clear energy imbalance reserve on it as well, since both energy and energy imbalance reserve are simultaneously and endogenously determined. Thus, while it is possible that this limitation may preclude a theoretically more efficient market-clearing solution, its practical impact on the market may be quite small.[114]

It is entirely possible that with further technical development work (and as computational technology steadily progresses over time), we may be able to remove this limitation; nevertheless, out of an abundance of caution, we concluded it was prudent to be clear with market participants about the rationale and necessity of this limitation, and to incorporate this limitation in the clearing-related provisions in new Section I.10.8(a)(ii) of the Tariff.

► **Reserve Constraint Penalty Factor for the forecast energy requirement.** Reserve Constraint Penalty Factors are an existing feature of the ISO's real-time reserve markets and the Tariff. They serve to limit the costs incurred to procure reserves, and to signal in market prices the value of reserve shortages if they do occur.

More specifically, a Reserve Constraint Penalty Factor serves as a 'cap' on the cost (in $/MWh) that the co-optimized market solution would incur to satisfy a reserve demand quantity. That is, if the "re-dispatch" cost to satisfy a reserve demand quantity exceeds the Tariff-proscribed Reserve Constraint Penalty Factor, then the market will stop short of fulfilling the demand quantity for that type of reserves. In such situations, the Reserve Constraint Penalty Factor will either set (directly)

[113] For additional information and context, *see* Energy Security Improvements: Market-Based Approaches, Presentation to NEPOOL Markets Committee, dated November 12-13, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/11/a4_a_iso_presentation_energy_security_improvements.pptx, at slides 34-44.

[114] *Id*. at slides 40, 43.

the reserve product's market price, or be used to set (in combination with other reserve products' market prices) the reserve product's price.

Each reserve-related constraint in a co-optimized market, both in the ISO's existing real-time market and in the day-ahead market upon the implementation of the Energy Security Improvements, requires a Reserve Constraint Penalty Factor.[115] For energy imbalance reserve, the relevant Reserve Constraint Penalty Factor is that applied to the forecast energy requirement in equation (FER) (*see* Section 6.4.1). This is because Reserve Constraint Penalty Factors are technically applied to the (exogenous) Demand Quantities that define how much should be procured to satisfy the applicable constraint. There is no separate Reserve Constraint Penalty Factor for the (endogenous) Energy Imbalance Reserve Demand Quantity, as its maximum 'cost cap' will be handled by the Reserve Constraint Penalty Factor for the forecast energy requirement.

The forecast energy requirement is a new type of constraint, and requires a new Reserve Constraint Penalty Factor value. In determining this value, our primary economic consideration is the relative value of a shortage of energy imbalance reserve, relative to the other day-ahead ancillary services that are simultaneously procured in the co-optimized day-ahead market (namely*.,* generation contingency reserves and replacement energy reserves).

Put simply, the forecast energy requirement results in the day-ahead market procuring energy imbalance reserves to satisfy the *expected* real-time load in the New England Balancing Authority Area during the applicable hour of the next day. In contrast, the other day-ahead ancillary services are primarily intended to prepare the system, on a day-ahead basis, to be able to respond to contingencies or other *unexpected* events during the operating day – which may, or may not occur. For these reasons, it is economically appropriate that the maximum cost that the co-optimized market will incur to satisfy the forecast energy requirement should be greater than the maximum cost to procure the other ancillary services. Stated simply, the market-clearing should prioritize being prepared to satisfy the real-time load that is expected (*i.e.,* forecast) to occur, over procuring other reserve products for contingencies that may not occur.

This logically implies that the Reserve Constraint Penalty Factor for the forecast energy requirement should be a higher numerical value than the Reserve Constraint Penalty Factors used for the other ancillary services procured in the co-optimized day-ahead market. And indeed, the values filed with the Energy Security Improvements will satisfy this property, for the foregoing reasons.

However, there is another, more technical dimension to this logic as well. The other types of day-ahead ancillary services (generation contingency reserve and replacement energy reserve) are designed with a 'nested' structure: faster-ramping reserve products are able to meet the demand both for fast-ramping capability as well as the demand for slower-ramping capability. For example, Day-Ahead Ten-Minute Generation Contingency Reserve is able to satisfy not only the Day-Ahead Ten-Minute Reserve Demand Quantity, but also the Day-Ahead Thirty-Minute Reserve Demand

[115] As a technical matter, all reserve constraints also require a Reserve Constraint Penalty Factor to ensure there is a mathematically feasible solution to the co-optimization. That technical observation does not guide the choice of a numerical value for the Reserve Constraint Penalty Factor, which is the issue at hand.

Quantity, the Day-Ahead Ninety-Minute Reserve Demand Quantity, and the Day-Ahead Four-Hour Reserve Demand Quantity. And, correspondingly, the market prices for each of these product also 'nest' – a property known as *price cascading*: the market price of a faster-ramping reserve product is always greater than (or equal to) the price of the next slower-ramping reserve product. (For more details, *see* Section 7.2.3).

As applicable to Reserve Constraint Penalty Factors, this means that to prioritize the forecast energy requirement over all other day-ahead ancillary services, it is not sufficient to set the Reserve Constraint Penalty Factor to (just) be the highest value of them all. Rather, the Reserve Constraint Penalty Factor for the forecast energy requirement must be set higher than the *sum* of all other ancillary services' Reserve Constraint Penalty Factors.[116] In this way, if there are insufficient energy call option offers to satisfy both the forecast energy requirement and all other day-ahead ancillary services demand quantities, the co-optimized market solution will signal a shortage of the other ancillary service products first, and a shortage of the forecast energy requirement last. That is, the market-clearing software will prioritize being prepared to satisfy the real-time load that is expected (*i.e.,* forecast) with energy and energy imbalance reserve, relative to the other day-ahead reserve products for contingencies that may not occur. And that is the intended prioritization outcome, if such a situation were ever to be necessary.

In the Tariff, this is implemented by specifying the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity by formula, or reference, to all *other* day-ahead ancillary service Reserve Constraint Penalty Factor values. Specifically, new Section III.2.6.2(b)(vi) stipulates that the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity will be set at 101 percent (that is, just above) the sum of all other day-ahead ancillary service Reserve Constraint Penalty Factor values (which, for convenient reference, are listed in Sections III.2.6.2(b)(i) - (vi)).

Doing the math, the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity is $2,929/MWh.[117] However, the reasonableness of this value rests not on this number in isolation; rather it rests upon: (a) the foregoing logic that it is appropriate to prioritize the forecast energy requirement (that is, energy and energy imbalance reserve) over other forms of day-ahead reserves; and (b) the numerical values of the Reserve Constraint Penalty Factors for those other forms of reserves. (For details on the latter, *see* Section 7.4).

Last, a reality check. In order for the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity to set price in the day-ahead market, the day-ahead market would have to have insufficient supply offers (for both energy and energy options *combined*) to cover the *forecast load the next day.* That seemingly rare prospect would be a major event, signaling the system is at significant reliability risk the next day. In such circumstances, it would be economically

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[116] This is, specifically, due to the additive (cascading) shadow price structure explained in Section 7.2.3. *See* Table 7-4.

[117] Using the values in Tariff Sections III.2.6.2(b)(i) - (vi), this calculation is: 101% × ($50 + $1500 + $1000 + $250 + $100) = $2,929.

logical for that expected real-time energy shortage to be signaled throughout the region with a very high day-ahead market price.

6.5 Virtual Transactions and the Forecast Energy Requirement

In this section, we address the settlement treatment of virtual transactions in the co-optimized day-ahead market. Our primary point is that virtual supply and demand will continue to be credited and charged (respectively) at the day-ahead LMP, as they are today. That is, virtual supply is not paid the Forecast Energy Requirement Price, and virtual demand is not allocated its cost. We explain the economic logic and rationale for this treatment, and why it is consistent with sound pricing principles.

There is an allocation of a portion of energy imbalance reserve costs to virtual supply, however, on a cost-causation basis. We explain this rationale as well.

► **Concepts: Virtual supply and the energy gap.** As context, it is useful to revisit how virtual supply can impact the day-ahead energy gap in today's energy-only day-ahead market, and the amount of energy imbalance reserve procured in the co-optimized day-ahead market.

Consider again simple example (d) from Section 6.1. There, we assumed the day-ahead market clears 20 GWh of energy demand in total for a particular hour, and that this exactly matches the forecast energy demand of 20 GWh.

In that example, however, not all day-ahead cleared energy supply is from physical supply resources. Specifically, the market cleared 19 GWh from physical supply resources (*e.g.,* generation, Demand Response Resources, and imports), and cleared 1 GWh of virtual supply (Increment Offers). The total day-ahead cleared energy supply is 19 GWh physical supply + 1 GWh virtual supply = 20 GWh. In effect, 1 GWh of virtual supply displaced competing physical suppliers in this day-ahead market example.

Now consider the energy gap between forecast energy demand and day-ahead cleared energy from physical supply resources. There is only 19 GWh of day-ahead cleared energy supply from physical supply resources to meet the 20 GWh of forecast energy demand the next operating day. In today's day-ahead energy-only market, this produces an energy gap of 1 GWh in the system's next day's operating plan:

20 GWh *forecast energy demand* – 19 GWh *cleared physical supply* = 1 GWh *energy gap.*

Today, in developing its next-day operating plan, this would result in the ISO relying upon 1 GWh of resource capabilities that did not clear in the day-ahead market to cover this energy gap. For the reasons explained in Section 2, such resources have inefficiently low incentives to arrange fuel in advance of the operating day, because they receive no day-ahead compensation for doing so. Moreover, if necessary, the ISO would supplementally commit after (that is, outside of) the day-ahead market the additional generation necessary to ensure sufficient resources are available to meet the forecast energy demand the next day.

With the co-optimized day-ahead market, an energy gap that results when virtual supply clears will be covered within the day-ahead market. Assuming (for purposes of this simple example) that the co-optimized market will still clear 19 GWh of energy from physical supply resources, the co-optimized day-ahead market will now procure 1 GWh of energy imbalance reserve in order to satisfy the forecast energy requirement. The energy gap is now covered:

19 GWh *energy from cleared physical supply* + 1 GWh *EIR* ≥ 20 GWh *forecast energy demand*.

In summary, the main points of this simple example are two. First, in the energy-only day-ahead market today, cleared virtual supply can contribute to the energy gap. And second, in the co-optimized day-ahead energy market, energy imbalance reserve will cover (or contribute to covering) that energy gap.

► **Implications.** Viewing this simple example from a broader perspective, it highlights that from the perspective of the costs of preparing and operating a reliable power system, there is a 'hidden' cost associated with virtual supply that is not priced transparently today.

Specifically, virtual supply must be 'replaced' with physical supply in order for the system to have a reliable next-day operating plan. That has a real cost, and that cost has always been present; but it is manifest in the inefficiently low incentives to arrange fuel for the resources that the ISO must rely upon in its next-day operating plan (but did not receive a day-ahead market obligation), as explained in Section 2; or manifest in the cost of supplemental commitments made outside of the market (which contribute to uplift costs); or both.

With a co-optimized day-ahead market with energy and energy imbalance reserve, that 'hidden' cost is now transparently priced. It is reflected in the payments to be made at the energy imbalance reserve price to resources that acquire energy imbalance reserve obligations. These now cover the energy gap when cleared virtual supply offers contributes to insufficient energy clearing from physical supply resources to satisfy the forecast energy requirement.

Logically, it is consistent with cost-causation principles that virtual supply should be allocated the 'replacement cost' the system incurs when virtual supply clears and energy imbalance reserve is procured to replace it. That replacement cost rate is now transparent: it is the energy imbalance reserve price. Accordingly, with the instant filing, a portion of the system's energy imbalance reserve payments will be allocated to cleared virtual supply. We discuss these charge allocation details, and corresponding Tariff provisions, in detail in Section 6.6.4 below.

► **Day-ahead energy settlement rates for virtual transactions.** Apart from energy imbalance reserve, there is another important settlement rate issue. It remains economically appropriate that virtual supply and demand that clears in the day-ahead market will continue to be settled day-ahead at the day-ahead LMP, as they are today – and that virtual supply is not paid the forecast energy requirement price.

Stated more precisely, in prior Sections 6.2 through 6.4 we explain why it is consistent with sound pricing principles that day-ahead cleared energy from physical supply resources will be paid the day-ahead LMP *plus* the forecast energy requirement price. In contrast, as we explain now, day-ahead cleared energy from virtual supply will be paid the day-ahead LMP, and not paid the forecast energy requirement price. This is not discriminatory treatment; far from it, this compensation design reflects the fact that day-ahead energy sales from physical and virtual resources are fundamentally *not* similarly situated with respect to their value in meeting the system's day-ahead forecast energy requirement. We explain this, and why these compensation rates are both economically-appropriate and consistent with sound pricing principles, next.

The participation payment principle. The appropriateness of this treatment of virtual supply is plainly evident from the perspective of the *participation payment principle,* explained earlier in Section 6.2.3. That principle states that a supply offer that participates in (contributes to) satisfying multiple requirements should be paid the price associated with each requirement. In the present context, however, virtual supply does not contribute to multiple requirements; it only contributes to one, and so is paid only one price: the day-ahead LMP.

Stated more precisely:

- The day-ahead LMP is the marginal cost of serving energy demand, and is the price associated with the market clearing requirement in equation (MCR) (*see* Section 6.4.1). Virtual supply comprises the term INC_h in equation (MCR). Cleared virtual supply offers therefore directly participate in – that is, contribute to – satisfying that requirement. Accordingly, cleared virtual supply must be paid the day-ahead LMP.

- The Forecast Energy Requirement Price is the marginal cost of satisfying forecast energy demand, and is the price associated with the forecast energy requirement in equation (FER) (*see* Section 6.4.1). Virtual supply, or INC_h, does not appear in equation (FER) and thus does not count toward total supply on the left-hand side of equation (FER). Cleared virtual supply offers therefore do *not* participate in – that is, do not contribute to – satisfying the forecast energy requirement. Accordingly, cleared virtual supply should not be paid the forecast energy requirement price.

- Similarly, virtual demand, or DEC_h, does not appear in equation (FER) and thus does not count toward total expected energy demand on the right-hand side of formula (FER). Cleared virtual demand offers therefore do not participate in – and do not increase the cost of satisfying – satisfying the forecast energy requirement. Accordingly, cleared virtual supply should not be charged the forecast energy requirement price.

At one level, this represents no change from today: virtual supply that clears day-ahead is paid the day-ahead LMP. In addition, real-time settlement rules remain unchanged. Thus, all cleared day-ahead virtual transactions are still settled at the real-time price. Therefore, the energy market settlement of virtual transactions is unchanged from that in effect today, and no new rules are required.

Marginal-cost pricing principles. In Section 6.2, we emphasized that the pricing and payment rules in the co-optimized day-ahead market with energy and energy imbalance reserve satisfy sound economic principles, in part because they reflect the fundamental principle of marginal-cost pricing. Since virtual supply and physical supply that clear energy day-ahead will be paid different total day-ahead settlement rates for the energy they clear, it is useful to reconcile how those different total payment rates are *both* consistent with marginal-cost pricing.

The core insight is that there are different marginal costs of serving day-ahead demand with virtual supply offers, versus serving day-ahead demand with physical supply offers. The difference is the cost of the energy imbalance reserve required with the former, but not required – indeed, avoided – with the latter. Those different marginal costs line up precisely with the different total settlement rates to be paid to virtual supply and paid to physical supply that clear in the co-optimized day-ahead market.

Consider the change in the system's costs, at the margin, if a participant offered incrementally more cleared (infra-marginal) virtual supply. If the day-ahead market's energy supply offer at the margin is from a physical resource, the incremental virtual supply would save the system the marginal cost of energy supply from that physical resource. From Section 6.2, that is equal to:

MC of energy supply = DA LMP + FERP

(where FERP is the forecast energy requirement price). *See* again Figure 6-3.

However, clearing incremental virtual energy supply in lieu of the marginal physical resource's energy supply would result in the need to also procure incremental energy imbalance reserve to satisfy the forecast energy requirement. The marginal cost of that incremental energy imbalance reserve must be accounted for. The total reduction in the system's costs, at the margin, with an increment of cleared virtual energy supply is therefore the difference between the marginal cost of energy supply and the marginal cost of energy imbalance reserves:

MC of energy supply (an avoided cost) – MC of EIR (an incurred cost)

which, combining both of these formulas, is:

DA LMP + FERP – EIR Price.

Here, as always, the Forecast Energy Requirement Price equals the energy imbalance reserve price. Thus the reduction in the system's costs, at the margin, when there is incrementally more cleared virtual supply is simply the day-ahead LMP. Thus, the proper marginal-cost based payment rate to virtual supply is the day-ahead LMP.

The main point here is important. It is consistent with sound economic principles that the day-ahead market's payment rate for virtual transactions is the day-ahead LMP, as it is today. That is, virtual supply is not paid the Forecast Energy Requirement Price, and virtual demand is not allocated its cost. However, for the reasons discussed above, a portion of energy imbalance reserve costs are allocated to virtual supply, on a cost-causation basis.

6.6 Settlements and Cost Allocation

Sections 6.2 through 6.5 explained the economic logic and principles for the settlement rates associated with the forecast energy requirement and energy imbalance reserve. In this section we summarize their cost allocation and its rationale. In addition, below we provide additional explanation of the new Tariff provisions governing these settlement and allocation rules.

6.6.1 Forecast Energy Requirement Credits

The payment of the Forecast Energy Requirement Price to physical supply resources that clear energy in the day-ahead market is provided in new Section III.3.2.1(q)(5) of the Tariff, and is called the Forecast Energy Requirement Credit.

These Forecast Energy Requirement Credits are paid to Generator Assets, Demand Response Resources (which participate as "supply" in the energy markets), and import External Transactions. These resource types correspond with the types of supply that contribute to – that is, participate in – the forecast energy requirement as shown in equation (FER) in Section 6.4.1.

Note that there exists no real-time analog to the Forecast Energy Requirement Price. Put differently, there is no separate 'forecast *in* real-time' of 'demand *in* real-time'; there is only one real-time demand – the actual system load. This means there is no 'close-out' or deviation charges associated with the Forecast Energy Requirement Credit, as there is when a market participant's real-time energy differs from its day-ahead cleared energy. The real-time settlement for deviations from a participants' day-ahead energy obligation is at the real-time LMP (which is not altered in this filing). *See, e.g.,* cases (i) and (j) in Section 4.3.2.

6.6.2 Forecast Energy Requirement Cost Allocation

The cost allocation of the Forecast Energy Requirement Credit is provided in new Section III.3.2.1(q)(6) of the Tariff, and is called the Forecast Energy Requirement Charge.

These costs are allocated primarily to the system's real-time load, on the 'beneficiaries-pay' principle. The reasoning is that the forecast energy requirement exists to ensure the power system is prepared to reliably deliver energy to load *in real-time*. Real-time load is, therefore, ultimately the beneficiary of the costs incurred to satisfy the system's forecast energy requirement.

There are two exceptions of note:

- New Section III.3.2.1(q)(6)(i) provides that cleared day-ahead export External Transactions will be charged a rate equal to the Forecast Energy Requirement Price. These are the only *day-ahead* energy obligations subject to the Forecast Energy Requirement Charge.

  The reason for this treatment is that day-ahead exports are *not* included in the ISO's load forecasting process. Rather, the total MWh of cleared day-ahead exports are accounted for separately in the forecast energy requirement (*see* equation (FER) in Section 6.4.1). Their separate accounting in the forecast energy requirement constraint in the co-optimized day-ahead market means that each additional MWh of day-ahead cleared exports has a direct, cost-causative impact on the total Forecast Energy Requirement Credit. That is, an increment of cleared MWh of day-ahead exports requires an incremental MWh of either energy from physical supply resources, or of energy imbalance reserve, to be procured to satisfy the forecast energy requirement. Thus, day-ahead cleared exports are charged the Forecast Energy Requirement Price.

Note further that this treatment means if a market participant clears both day-ahead imports and day-ahead exports for the same hour (possibly on different external interfaces), they will receive either a net credit or charge for their *net* external transaction MWh. That netting outcome is economically desirable, to avoid distorting external transaction scheduling incentives (which could otherwise occur if exports and imports were charged and credited at different payment rates for the same hour).

- New Section III.3.2.1(q)(6)(ii) contains an exclusion from the Forecast Energy Requirement Charge for the real-time load of storage resources (*i.e.,* the energy consumed in real-time for charging). In the Tariff, storage resources are known as Storage DARDs (short for Storage Dispatchable Asset-Related Demands).

  The reasons for this exclusion are two. First, the ISO's load forecast does not include real-time load used by energy storage resources. Thus, the forecast energy requirement in constraint (FER) is not being enforced on their behalf, as it is for the (firm) load that is being forecast by the ISO in the New England Balancing Authority Area. The second reason is to avoid inefficiently distorting storage resources' charging behavior in the real-time energy market. If, counterfactually, storage resources' real-time loads were subject to the Forecast Energy Requirement Charge, then the effective price the storage resource would face for its real-time load would not be the real-time LMP, but instead would be a higher effective price – incorporating the additional (per-MWh) cost it would incur for its share of the Forecast Energy Requirement Charge. That higher effective charging price would create unintended, inefficient consequences in the real-time energy market, inasmuch as energy storage resources' real-time charging decisions would no longer be based on the system's real-time marginal cost of energy.

6.6.3 Energy Imbalance Reserve Credits and Charges to Sellers

Recall that market participants with cleared energy call option offers have two settlements associated with their energy call options. The first is a credit, at the market clearing price of the ancillary service product for which the energy option was cleared. The second is a charge, or the option close-out, which is at the maximum of the real-time LMP less the strike price, or zero. *See* examples (a) through (j) in Section 4.3.

The new Tariff provisions provide that each MWh of a seller's cleared energy imbalance reserve will receive a payment at the day-ahead clearing price for energy imbalance reserve, and the corresponding option close-out charge.

- New Section III.3.2.1(a)(2)(vi) stipulates that market participants with cleared energy call option offers that contribute to satisfying the forecast energy requirement receive a Day-Ahead Energy Imbalance Reserve Obligation.

- New Section III.3.2.1(q)(1)(vi) provides for the seller's credit. It stipulates that each MWh of Day-Ahead Energy Imbalance Reserve Obligation will be paid the clearing price for Day-Ahead Energy Imbalance Reserve Obligation.

- New Section III.3.2.1(q)(2)(ii) provides for the seller's option close-out charge. It stipulates that each MWh of Day-Ahead Energy Imbalance Reserve Obligation will be charged the energy option close-out amount. The option close-out amount is based on the Real-Time Hub Price and the energy option strike price, as explained in Section 4.3.2 (on option settlement location) and Section 4.5.2 (on strike prices).

  As a Tariff drafting note, provisions (i) and (ii) of new Section III.3.2.1(q)(2) are written separately for generation contingency reserve and replacement energy reserve in (i), and for energy imbalance reserve in (ii), solely for purposes of separate cross-referencing of (i) and (ii) from other portions of the Tariff.

6.6.4 Energy Imbalance Reserve Cost Allocation and 'Close-Out' Offsets

► **Concepts and rationales.** Like the energy imbalance reserve credits and charges to sellers, the energy imbalance reserve cost allocation has two components. One is the cost allocation (a charge) associated with the day-ahead energy imbalance reserve price paid to sellers. The second is the close-out offset (a credit) associated with the close-out of seller's day-ahead energy options.

From a broader perspective, these two components are the 'opposite' side of an energy call option seller's position. Conceptually, (most) market participants that are allocated the costs of the energy call options are effectively receiving a 'hedge' against the real-time LMP. They pay the clearing price for the energy call option; and by doing so, they receive a hedge at the energy call option strike price for their real-time price exposure. (For additional discussion, see Frequently-Asked Question 7 in Section 6.2.4, above.)

In developing this cost allocation for energy imbalance reserve, we sought to allocate these costs on a $/MWh basis that mirrors the $/MWh basis that sellers receive for their energy imbalance reserve credits/charges. That is, the cost allocation rules do not simply divide the total costs to be allocated among the MWh to which they will be allocated on a pro-rata basis. Rather, they seek to line up the cost-allocation rate with the credits-to-sellers rate. This is in keeping with the design intent that an energy call option's cost allocation reflects the opposite side of the energy call option seller's position.

The primary cost allocation for energy imbalance reserve is based on: (a) a market participant's real-time load in excess of its day-ahead cleared energy purchases, in MWh; and (b) a market participant's virtual supply offers cleared day-ahead, in MWh (which are equal to those offers' real-time deviations, by the nature of virtual supply). The reasoning for energy imbalance reserve cost allocation to these deviations is based on cost-causation. Specifically:

a) For load deviations, the reasoning is that if these market participants' had procured energy day-ahead instead of waiting to procure energy only in real-time, then (on average) the system's energy gap would be smaller and less energy imbalance reserve would be procured. We say 'on average' because the load forecast is accurate on average (*see* Section 6.4.1).

b) For virtual supply, the reasoning is the cost-causation explanation in Section 6.5 above.

Finally, there can be situations in which the market's total cleared energy imbalance reserve MWh is larger than the total MWh of deviations in (a) and (b) combined. In such cases, there will be some "residual" energy imbalance reserve costs to be allocated, after allocating the applicable credits/charges to the deviations in (a) and (b) above. The residual costs to be allocated will flow to real-time load obligations, on a beneficiaries-pay basis.

► **Corresponding Tariff provisions.** The cost allocation provisions for energy imbalance reserve are contained in new Section III.3.2.1(q)(4). Deviations-based cost allocations are difficult to specify precisely in words, so there are multiple parts:

- Section III.3.2.1(q)(4)(i) defines the relevant load deviations. Note that deviations related to the energy purchased by Storage DARDs is excluded from this allocation, for the same reasons discussed in Section 6.6.2 above.

- Section III.3.2.1(q)(4)(ii) allocates the cost of payments to sellers of energy imbalance reserve. This is in three parts:

  The second paragraph in that new subsection covers the case where the market's total cleared energy imbalance reserve MWh is larger than the total MWh of deviations; in this case, the costs are allocated to load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)) and to virtual supply MWh on a $/MWh basis, and the residual costs remaining are allocated to real-time load.

  The third paragraph covers a case where the market's total cleared energy imbalance reserve MWh is smaller than the total MWh of deviations; in this case, the costs are allocated to virtual supply MWh on a $/MWh basis because there is a one-to-one relationship between virtual supply and additional cleared energy or energy imbalance reserve from physical supply resources (*see* Section 6.5). The residual costs are allocated to the remaining load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)) on a pro rata basis.

  The fourth and final paragraph covers the case where there are no load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)), so all costs are allocated to virtual supply MWh on a $/MWh basis.

- Section III.3.2.1(q)(4)(iii) allocates the credits resulting from the energy call option close-out charges (the close-out charges being paid by the sellers of energy imbalance reserve, as discussed with respect to Section III.3.2.1(q)(2)(ii) in Section 6.6.3). This section is again in three parts, structurally matching the corresponding three parts in Section III.3.2.1(q)(4)(ii).

7. Generation Contingency Reserve and Replacement Energy Reserve

In this section, we provide design detail for the new day-ahead generation contingency reserve and replacement energy reserve ancillary services. We address their purpose, explain their inter-related product structure, and provide historical data to inform the quantities demanded for these day-ahead ancillary services. We also provide numerical examples of co-optimized day-ahead market clearing with generation contingency reserve and replacement energy reserve, in order to illustrate their pricing properties.

7.1 Purpose

With the addition of energy imbalance reserve, the day-ahead market under the Energy Security Improvements will prepare the system to meet the *expected* (that is, forecast) supply and demand conditions during the next operating day. In practice, actual supply and demand conditions during the operating day may differ, for a number of possible reasons. These include unexpected generation derates and outages, weather changes that cause unanticipated increases in energy demand relative to forecast, and so on.

Broadly, the purpose of day-ahead generation contingency reserve and replacement energy reserve is to provide a margin for such uncertainties. With these products, the day-ahead market will help provide a next-day operating plan to reliably supply energy when operating conditions unexpectedly deviate from those forecast day-ahead.

At a high level, generation contingency reserve is a set of ancillary service products designed to prepare the system to be able to successfully respond to sudden, unanticipated energy supply loss during the operating day. When that occurs, the system requires fast-ramping / fast-start response capabilities ‘at the ready’ in order to promptly close the resulting gap between energy supply and demand (consistent with the timeframes established in applicable reliability standards). With these Energy Security Improvements, these response capabilities will now be procured in the co-optimized day-ahead market.

Replacement energy reserve is a set of ancillary service products designed to prepare the system to handle an unanticipated loss of supply, or unanticipated increase in demand, that persists for a significant (multi-hour) period of time during the operating day. In practice, following an unanticipated loss of a resource scheduled day-ahead to supply energy, the system can use the energy from generation contingency reserve for only a limited period of time; those fast-start / fast-ramping capabilities must be restored to reserve (that is, non-energy producing) status, in sufficient amounts to withstand the *next* possible contingency, within prescribed time limits. After that point, the system requires replacement energy to cover the unanticipated gap in the operating plan’s supply-and-demand balance through the remainder of the day.

On the demand side, the system also requires replacement energy to serve *unexpected* increases in energy demand, relative to the day-ahead forecast. If the system has insufficient replacement energy to cover an unexpected increase in energy demand – in effect, to compensate for error in the day-ahead load forecast[118] – the system can suffer from a problem known as the *cannibalization of reserves*. This occurs because (with rare exception) serving unexpected increases in energy demand during the operating day takes priority over maintaining reserve. To do so, the system will dispatch resources for energy as needed, at the expense of the system's reserve capability.

In general, the system's real-time dispatch will seek to preserve its faster-ramping capabilities for real-time contingency response in such situations, so the cannibalization problem results in having less capability to restore contingency reserves to reserve status should an unanticipated supply loss occur. To avoid this cannibalization problem, under the Energy Security Improvements, the day-ahead market will procure replacement energy reserve quantities to cover for both the potential loss of supply from the system's largest day-ahead scheduled resource through the balance of the day, and to cover for unanticipated increases in energy demand (that is, above the day-ahead forecast).

As noted at the outset of this paper, New England's existing energy-only day-ahead market does not procure, or compensate for, generation contingency reserve or replacement energy reserve. Instead, presently the ISO employs unpriced constraints in its day-ahead market unit commitment process to help ensure these capabilities will be available, and it employs out-of-market procedures and reliability-commitment tools (after the day-ahead market) to evaluate the system's preparedness to handle uncertainties the next operating day.[119] But as discussed previously, these out-of-market practices are increasingly problematic.

Generation contingency reserve and replacement energy reserve are inherently needed to address *unanticipated* system events – and, as a result, the resources the ISO relies upon in its next-day operating plan for these capabilities typically have no reason to *expect* to run (or, for those with a day-ahead energy schedule, no reason to expect run above, or for longer than, that day-ahead schedule). As discussed in detail in Section 2.7 earlier, for that reason and others, the resources that provide these essential reliability services presently face inefficiently low market incentives to arrange energy supplies in advance of the operating day – even when such arrangements would be a cost-effective means to reduce reliability risks from society's perspective. As a result, the ISO is increasingly concerned that if the system experiences unexpectedly high demand, an unanticipated, extended supply loss, or both – particularly if it occurs when renewable resources' production capability is low (when the sun is down or the winds are calm) – the region may not have the energy needed to reliably fill the ensuing energy gap.[120]

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[118] This is in contrast to energy imbalance reserve, which seeks to address the gap between the amount of physical supply procured day-ahead and the forecast. Replacement energy reserve is aimed at addressing gaps that arise where the forecast itself is inaccurate.

[119] *See* Brandien Testimony at pp. 17-21; *see also* Section 2.6.1, 2.7 above.

[120] *See,* generally, Brandien Testimony at pp. 23-26.

To better address these concerns, upon implementation of the Energy Security Improvements, the co-optimized day-ahead market will procure generation contingency reserve and replacement energy reserve as new day-ahead ancillary services. At a high-level, the design provides the ISO with the option to "call" on the energy of a day-ahead seller of these ancillary services during the operating day, above and beyond its day-ahead energy schedule (whether or not it has one), in amounts and over timeframes that are designed to match the reliability standards detailed in the accompanying Brandien Testimony.[121]

Each new day-ahead ancillary service will be procured at a uniform and competitively-determined price, providing ancillary service sellers with greater compensation than they receive for these capabilities today (which, in today's day-ahead market, is zero). Importantly, the settlement of these ancillary services uses the energy call option design, thereby providing – for all the reasons explained in Section 4 and 5 previously – an economically sound solution to the misaligned incentives problem for the resources that provide these services. In this way, the new day-ahead generation contingency reserve and replacement energy reserve ancillary services will better address the region's fuel security concerns – while signaling, through new, transparent prices, the costs of a reliable next-day operating plan.

7.2 Products and Their Demand

Generation contingency reserve and replacement energy reserve comprise a set of day-ahead ancillary services that are expressly time-dependent, in order to match the requirements of existing time-denominated reliability standards. These ancillary service products have a hierarchical, or nested, product structure that is important to how the quantities demanded and their clearing prices are determined. We explain these products, their time-related attributes, and their product structure next.

7.2.1 Product Specifications

Together, generation contingency reserve and replacement energy reserve refer to a set of five distinct resource capabilities. They are differentiated by the response-time requirements for each product.

Generation contingency reserve comprises three day-ahead ancillary service products:

GCR 10 Spin: Day-Ahead Ten-Minute Spinning Reserve;

GCR 10 Non-spin: Day-Ahead Ten-Minute Non-Spinning Reserve; and

GCR 30: Day-Ahead Thirty-Minute Operating Reserve (which may be provided by on- or off-line resources).

[121] *See* Brandien Testimony at pp. 6-12; *see also* Section 2.6 above.

Replacement energy reserve comprises two day-ahead ancillary service products:

RER 90: Day-Ahead Ninety-Minute Reserve (which may be provided by on- or off-line resources); and

RER 240: Day-Ahead Four-Hour Reserve (240-minute reserve, which may be provided by on or off-line resources).

These ancillary service products correspond to resources' ramping capabilities (or, if scheduled to be offline, startup and ramping capabilities), above and beyond their day-ahead market energy schedules (whether or not they have one). For example, a resource's day-ahead 10-minute ancillary service product award depends upon (and is limited by) the resource's 10-minute ramping capability above its day-ahead energy schedule for the hour (or, if scheduled to be offline for the hour, its 10-minute startup and ramping capability); and similarly for the additional products. Indeed, and as explained in greater detail below, the two replacement energy reserve products are natural extensions of the generation contingency reserve products, differentiated by time.

► **Day-ahead reserves are energy options.** The co-optimized day-ahead market will procure, and compensate for, these five resource capabilities with financially-binding awards (*i.e.,* obligations). Conceptually, an ancillary service award provides the ISO with the option to call on the seller's resource's energy "on demand" during the operating day, to be delivered within the timeframe defining each product. A day-ahead ancillary service obligation is financially-binding in that it creates a settlement obligation, as a call option on energy, during the obligation hour in the manner described in Sections 4.2 and 4.3.

The three generation contingency reserve products mirror the three fast-start or fast-ramping capabilities that the ISO presently designates and compensates in its real-time market as operating reserves (namely, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve). Those real-time designations similarly measure resources' unloaded capability that can ramp up, or startup from an offline state, to deliver additional energy within 10 or 30 minutes.[122]

As noted in Section 4.1, the day-ahead generation contingency reserve product awards will not settle against the real-time prices associated with real-time reserve designations. Rather, day-ahead generation contingency reserve awards will be settled, using the standard options settlement rules, against the real-time price of *energy.* For the reasons explained in Section 5.4, the incentives for resources to arrange more robust energy supply (fuel) arrangements are superior – *i.e.,* more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, instead of being settled using real-time reserve prices.

► **Product time parameters.** The specific time horizons that differentiate each of these day-ahead ancillary service products are expressly based on existing reliability standards. Specifically, the 10-

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[122] The ISO does not designate or compensate 90-minute or four-hour reserves in its real-time markets. *See* footnote 48 above.

minute and 30-minute response capabilities enable the system to be prepared, as part of its next-day operating plan, to meet (among other things) requirements for contingency reserve. As explained in the Brandien Testimony:

- **Ten-minute** reserve serves to meet NERC BAL-002-3 Requirement R1 and NPCC Regional Reliability Reference Directory #5 Requirement R1 (a portion of which must be ten-minute synchronized reserve, under the latter);[123] and

- **Thirty-minute** reserve serves to meet NPCC Regional Reliability Reference Directory #5 Requirement R2.[124]

The 90-minute and four-hour response capabilities enable the system to be prepared, as part of its next-day operating plan, to meet (among other things) requirements for contingency reserve restoration. As further explained in the Brandien Testimony:

- Requirement R.3 of NERC-BAL-002-3 requires the Balancing Authority to "restore its Contingency Reserve to at least its Most Severe Single Contingency" within **ninety minutes** following the end of the Contingency Event Recovery Period;[125] and

- NPCC Directory #5 also prescribes a restoration time for Thirty-Minute Operating Reserve: "A Balancing Authority deficient in thirty-minute reserve for **four hours** . . . shall eliminate the deficiency if possible, or minimize the magnitude and duration of the deficiency."[126]

These resource response capabilities, their associated time dimensions, and their use in contingency reserve deployment and contingency reserve restoration are further explained in the numerical example provided in Section II of the Brandien Testimony.[127]

► **Reserves for load forecast error.** In addition, both NERC and NPCC anticipate that a Balancing Authority's forward-looking load forecasts are subject to error, and anticipate that reserves may be used to address forecast error. Currently, the ISO relies on Operating Reserve to help account for load forecast error.[128]

In this context, it is important to observe that energy imbalance reserve and the forecast energy requirement do not prepare the system for potential load forecast *error.* Rather, they prepare the system to serve the energy demand that is *expected* – that is, the energy demand that is forecast to occur – in each hour of the next operating day. In order for the system's next-day operating plan to be able to reliably satisfy an unanticipated increase in energy demand the next day (while meeting

[123] *See* Brandien Testimony at pp. 8-9.

[124] *See* Brandien Testimony at p. 9.

[125] Brandien Testimony at p. 11 (emphasis added).

[126] Brandien Testimony at p. 11 (emphasis added).

[127] *See* Brandien Testimony at pp. 13-17.

[128] *See* Brandien Testimony at p. 10.

its contingency-related reserve requirements), the system requires additional reserve capability. That additional capability, in effect, compensates for the potential for error in the day-ahead load forecast.

With respect to preparing the system on a day-ahead basis to account for load forecast error, we expect that replacement energy reserve may provide a lower-cost means to do so than higher-cost day-ahead generation contingency reserves (which, as noted, procure fast-start / fast-ramping capabilities analogous to the real-time Operating Reserves that the ISO presently relies upon to help account for load forecast error).[129] This potential lower-cost solution to addressing load forecast error is possible because in practice, errors in the day-ahead load forecast can become evident many hours in advance of real-time; thus, the longer-lead time replacement energy reserve products may effectively help address it.[130] Thus, the Energy Security Improvements include provisions that enable the ISO to procure and compensate day-ahead ninety-minute and four-hour replacement energy reserve products for load forecast error.[131]

In this way, this suite of day-ahead generation contingency reserve and replacement energy reserve ancillary services will enable the day-ahead market – without "out of market" actions – to satisfy the requirements of a reliable next-day operating plan. And it will provide the resources that the system relies upon for these purposes with the incentives, and economically appropriate compensation, to ensure they have energy supply arrangements in place to operate if needed the next operating day.

7.2.2 Ancillary Service Demands are Specified Cumulatively

From a market design standpoint, there is a second important implication of these time-dimensioned reliability standards. The demand quantities of generation contingency reserve and replacement energy reserve necessary to meet the applicable reliability standards depend on the largest potential energy supply losses, as well as the timeframes specified by those standards. Hence, in the day-ahead market, these ancillary service products' demands are specified cumulatively.

The details are (necessarily) complicated, reflecting the complexity of the standards themselves. But the idea is simple. Instead of expressing in the day-ahead market a demand for each ancillary service product *individually,* we can equivalently express those demands *cumulatively.* Doing so will enable the co-optimized market to serve these demands more cost-effectively, by enabling products to substitute for one another.

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[129] The cases evaluated in the Analysis Group's Impact Assessment consistently show generation contingency reserves have higher clearing prices than replacement energy reserve. This reflects the overall greater supply of the latter in the New England system. *See* Impact Assessment, Table 9.

[130] *See* Energy Security Improvements: Market-Based Approaches, Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion, Presentation to NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_ii_esi_rer_goal2_accounting_for_load_forecast_error.pptx, at Slides 13-14.

[131] *See* new Tariff Section III.1.8.5(d)-(e).

► **Example.** Here, an example may help. The Brandien Testimony provides a detailed numerical example with three resources, showing the amounts of contingency reserve and replacement energy required to respond, within the timeframes of existing reliability standards, to an unanticipated energy supply loss event.[132] Table 7-1 below reproduces, in part, the assumptions regarding potential supply loss resources and their sizes that appear in Table 1 in the Brandien Testimony.[133]

Table 7-1. Excerpt from Brandien Testimony Table 1 with Example Assumptions

	Pre-Contingency	Resource	Resource Size (MW)
[1]	First Contingency Loss	Resource A	1600
[2]	Second Contingency Loss	Resource B	1400
	Post-Contingency	**Resource**	**Resource Size (MW)**
[3]	First Contingency Loss	Resource B	1400
[4]	Second Contingency Loss	Resource C	1300

The discussion of this example in the Brandien Testimony explains, at length, the minimum amounts of contingency reserve and replacement energy required and the timeframes in which they are needed. In Table 7-2, we show the total ancillary service demands that would be used in the day-ahead market for the applicable hour, and the ancillary services capable of satisfying them, under this example's assumptions (as detailed in the Brandien Testimony).[134]

Table 7-2. Day-Ahead Demand Quantity Calculations for Brandien Testimony Example

	Cumulative Demand	Cumulative MWh	Determined by Resource(s)	Satisfied by Total DA Awards (MWh) of:
[1]	Total 10-min	1600	A	GCR10 spin + GCR10 nonspin
[2]	Total 30-min	2300	A + ½ B	GCR10 spin + GCR10 nonspin + GCR30
[3]	Total 90-min	3000	A + B	GCR10 spin + GCR10 nonspin + GCR30 + RER90
[4]	Total 240-min	3650	A + B + ½ C	GCR10 spin + GCR10 nonspin + GCR30 + RER90 + RER240

Here's the logic involved in Table 7-2, and how it aligns the day-ahead market's ancillary service demands with the system's reliability requirements. We take each row in Table 7-2 step by step.

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[132] *See* Brandien Testimony at pp. 13-17.

[133] *See* Brandien Testimony at p. 13.

[134] The example in the Brandien Testimony does not illustrate the 10-minute spinning reserve requirement, and as such it is omitted in Table 7-2 here. In practice, a portion of the total 10-minute reserve requirement must be maintained as spinning reserve. *See* Brandien Testimony at pp. 8-10. We account for 10-minute spinning reserve in Section 7.2.3 of this paper.

Day-ahead total 10-minute reserve demand quantity. Row [1] of Table 7-2 shows that the total reserve required to respond within 10 minutes is 1600 MWh, and is determined by the size of Resource A.[135] (Resource A is the largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 10 minutes (or less) would be 1600 MWh. This capability enables the system to ensure that the supply and demand balance (*i.e*., the energy gap) is recovered within 15 minutes of the contingency (as required by NERC BAL-002-3 R.1).[136]

Note that this ancillary service demand for total 10-minute reserve can be met by any combination of *two* distinct day-ahead ancillary service products, as shown in the final column of row [1] in Table 7-2. Specifically, the total 10-minute reserve demand of 1600 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve and GCR 10-minute non-spinning reserve. The market will clear whatever combination of these two ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 30-minute reserve demand quantity. Row [2] of Table 7-2 shows that the total reserve required to respond within 30 minutes is 2300 MWh, and is determined by the size of Resource A plus one-half of Resource B. (Resource B is the second-largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 30 minutes (or less) would be 2300 MWh.

The *incremental* reserve demand within 30 minutes is 700 MWh greater than the reserve demand within 10 minutes (that is, the MWh in row [2] less row [1] is 2300 MWh – 1600 MWh = 700 MWh). This incremental reserve capability enables the system to meet its 30-minute reserve requirement (as required by NPCC Regional Reliability Reference Directory #5 Requirement R2).[137]

From a market standpoint, this ancillary service demand for total 30-minute reserve can be met by any combination of *three* distinct day-ahead ancillary service products, as shown in the final column of row [2] in Table 7-2. Specifically, the total 30-minute reserve demand of 2300 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, and GCR 30-minute reserve. The market will clear whatever combination of these three ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 90-minute reserve demand quantity. Row [3] in Table 7-2 shows the total reserve required to respond within 90 minutes is 3000 MWh, and is determined by the size of Resource A plus the full amount of Resource B. (Resource B is the second-largest single potential energy supply

[135] Reserve resources are expected to be able to sustain their power output for at least one hour, and reserve awards in the (hourly) day-ahead market are denominated in MWh (not MW).

[136] *See* Brandien Testimony at pp. 14-15.

[137] *See* Brandien Testimony at p. 9.

loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 90 minutes (or less) would be 3000 MWh.

The *incremental* reserve demand within 90 minutes is 700 MWh greater than the reserve demand within 30 minutes (that is, the MWh in row [3] less row [2] is 3000 MWh – 2300 MWh = 700 MWh). This incremental reserve capability enables the system to meet its 90-minute requirement to restore its total 10-minute reserves to reserve status (as required by NERC BAL-002-3 R.3).[138]

From a market standpoint, this ancillary service demand for total 90-minute reserve can be met by any combination of *four* distinct day-ahead ancillary service products, as shown in the final column of row [3] in Table 7-2. Specifically, the total 90-minute reserve demand of 3000 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, and RER 90-minute reserve. As noted above, the market will clear whatever combination of these four ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 240-minute reserve demand quantity. Row [4] of Table 7-2 shows the total reserve required to respond within 240 minutes is 3650 MWh, and is determined by the size of Resource A plus Resource B plus one-half of resource C. (Resource C is the post-contingency second-largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 240 minutes (or less) would be 3650 MWh.

The *incremental* reserve demand within 240 minutes is 650 MWh greater than the reserve demand within 90 minutes (that is, the MWh in row [4] less row [3] is 3650 MWh – 3000 MWh = 650 MWh). This incremental reserve capability enables the system to meet the 240-minute standard regarding restoration of the system's total 30-minute reserves (per NPCC Regional Reliability Reference Directory #5).[139]

From a market standpoint, this ancillary service demand for total 240-minute reserve can be met by any combination of *five* day-ahead ancillary service products, as shown in the final column of row [1] in Table 7-2. Specifically, the total 240-minute reserve demand of 3650 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, RER 90-minute reserve, and RER 240-minute reserve. As noted above, the market will clear whatever combination of these five ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

[138] *See* Brandien Testimony at pp. 11, 15-16.

[139] *See* Brandien Testimony at p. 16.

► **Implications.** There are two main points to take from the extended example in the Brandien Testimony. First, it exemplifies a general property of the new day-ahead ancillary service design: both the timing, and the quantities to be procured, of the new day-ahead ancillary service products serve to enable the system to satisfy – through the market – existing reliability standards. In that way, they serve to enable the day-ahead market to meet the requirements of a reliable next-day operating plan, while providing the resources the ISO relies upon for these capabilities with stronger incentives to ensure they have energy supply arrangements in place in advance of the operating day.

Second, Table 7-2 shows that instead of expressing in the day-ahead market a demand for each ancillary service product *individually,* we can equivalently express those same demands *cumulatively.* Doing so enables the co-optimized market to count faster-responding ancillary service product awards toward the ancillary service demands applicable over longer timeframes (though not the reverse, as discussed below), improving the design's cost-effectiveness overall. Importantly, this cumulative representation of ancillary service demands is also used in the ISO's existing real-time reserve markets for the reserve products designated by the ISO in real-time, and it has proved to be an effective (if technical) demand representation technique for reserve-energy co-optimization since its inception nearly fifteen years ago.

7.2.3 Product Substitution and Price Cascading

► **Offers and clearing.** As discussed in Section 4.1, market participants that wish to sell day-ahead ancillary services will submit a single energy call option offer for their resource, in addition to the resource's energy supply offer.[140] That is, market participants will not submit separate offers to sell the 10-minute ancillary service products, 30-minute ancillary service product, 90-minute ancillary service product, and so on. The co-optimized day-ahead market clearing process will determine the most efficient (and profitable) assignment of the resource's energy supply offer and its energy call option offer to meet energy demand, forecast energy requirement, and the ancillary service demand quantities. We provide several examples to illustrate the co-optimized day-ahead market's clearing with generation contingency reserve and replacement energy reserve in Section 7.5-7.7 below.

A resource's ramping capability and scheduled on- or off-line status depend on its energy award for the hour. For example, a resource that is economically scheduled to supply energy at its maximum output level in the day-ahead market has no additional capability with which to provide reserve. And an online resource that can ramp quickly may be assigned a lower energy schedule if it is more efficient (and profitable) for the day-ahead market to clear most of its potential production capability for ancillary services. The day-ahead market clearing process, being jointly performed for energy and all ancillary services simultaneously, accounts for these physical resource capabilities and limits.

[140] Regardless of the day-ahead ancillary service product type a seller is awarded, in settlement each MWh of its award will be closed-out at the same Energy Call Option Strike Price. *See* Section 4.3.

► **Incremental capability assignments.** Importantly, in performing this co-optimization, the day-ahead market clearing will account for the physical capabilities of the resource in determining its ancillary service awards. This is done in a manner that assigns a resource's *incremental* ramping capability to products with longer time horizons.

As a simple example, consider a 500 MW resource that clears 200 MWh of energy in the day-ahead market for each hour of the day. Assume this resource has a 1 MW per minute ramp rate. That means it could ramp to an output level of 210 MW in 10 minutes, to 230 MW in 30 minutes, 290 MW in 90 minutes, and 440 MW in four hours (since 200 MW initial output + 240 min in four hours × 1 MW / min ramp rate = 440 MW in four hours).

Assume that this resource submits both energy supply and energy call option offers for all 500 MW of its capacity, and that energy call option offer is economic to clear for all five generation contingency reserve and replacement energy reserve products. Its awards would account for its cumulative ramping capability, but each award will equal its *incremental* ramping capability as shown in the table below.

Table 7-3. GCR and RER Award Example

Time (minutes)	Output (MW)	Incremental Output (MW)	Ancillary Service Award Type
0	200	0	-
10	210	10	GCR 10-min spinning reserve
30	230	20	GCR 30-min reserve
90	290	60	RER 90-min reserve
240	440	150	RER four-hour reserve

In this example, the resource can ramp from its scheduled energy output of 200 MWh. It can increase its power output by 10 MW to 210 MW within 10 minutes, so it would receive (at most) a 10 MWh award for day-ahead GCR 10-minute spinning reserve. It can increase its power output by an *additional* 20 MW (to 230 MW) within 30 minutes, so it would receive (at most) a 20 MWh award for day-ahead GCR 30-minute reserve. It can further increase its power output by an *additional* 60 MW (to 290 MW in total) within 90 minutes, so it would receive (at most) a 60 MWh award for day-ahead RER 90-minute reserve. And, as shown in the last row of Table 7-3, it can further increase its power output by an *additional* 150 MW (to 440 MW in total) within 240 minutes, so it would receive (at most) a 150 MWh award for day-ahead RER four-hour reserve.

Figure 7-1 provides a graphical interpretation of the resource-specific ramping capability and the associated ancillary service product award amounts for the assumptions in Table 7-3.

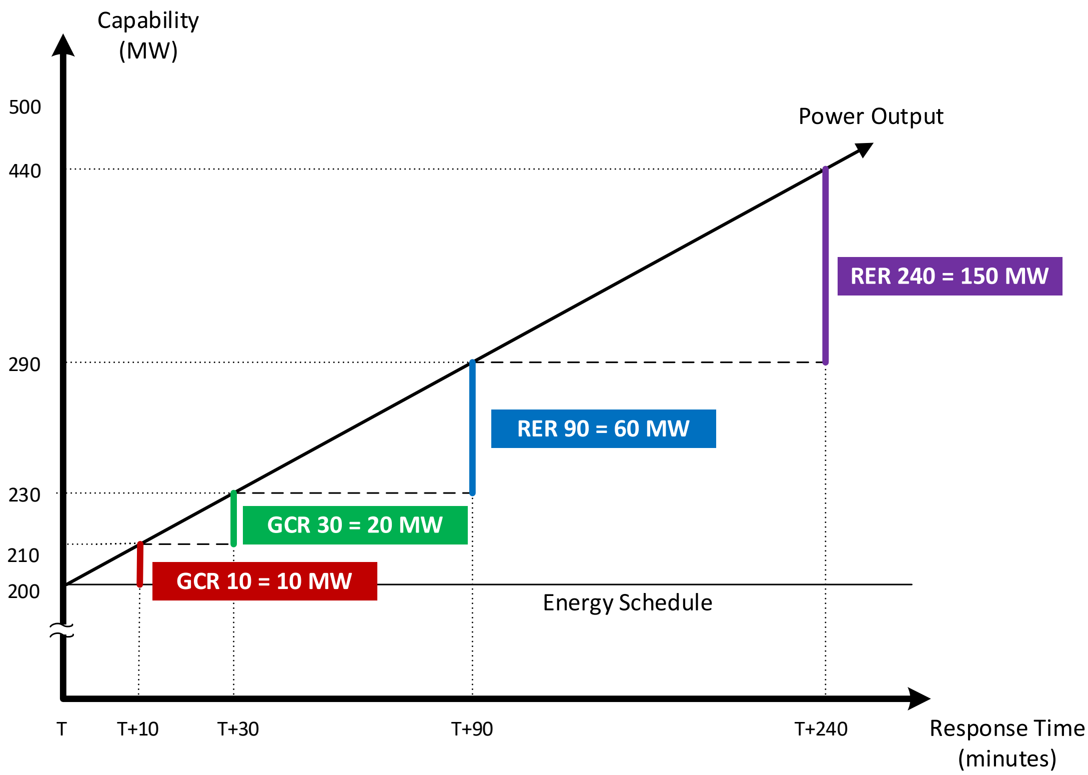

Figure 7-1. Incremental Reserve Awards for the Resource Assumptions in Table 7-3

In this way, the system is not counting the resource's initial 10 MWh of ramping capability toward two different products; that is, the system only counts the resource's *incremental* ramp capability to products with longer time horizons. This incremental capability award accounting system is designed to align well with a central feature of the generation contingency reserve and replacement energy reserve products' design, their product substitution structure. We address this next.

► **Product substitution.** Taken together, the five day-ahead ancillary service products that comprise generation contingency reserve and replacement energy reserve have an important, interdependent structure. In particular, the five generation contingency reserve and replacement energy reserve products are *one-way substitutes.* That means awards for a product with a shorter time horizon can substitute for awards with a longer time horizon in the market clearing process – but not the reverse.

Put differently, a resource's capability that can respond in 10 minutes or less (for example) will also help to satisfy the total demand for 30-minute reserve, and the total demand for 90-minute reserve, and the total demand for four-hour reserve. However, the reverse is *not* true: a resource's capability that can (only) respond within 30 minutes, but not within 10 minutes, does not help to satisfy the demand for 10-minute reserve.

Combining this property with the incremental capability assignment accounting discussed above provides a 'nested', or hierarchical, structure between each generation contingency reserve and replacement energy reserve product and the day-ahead ancillary service demand quantities they help to satisfy. A simple way to visualize this one-way structure of the generation contingency reserve and replacement energy reserve ancillary service products is shown in the graphic below.

Product Hierarchy for Generation Contingency Reserve and Replacement Energy Reserve

Time	Product	Demand Quantity	Typical Value
Shorter	**GCR 10 Spin** (helps meet all 5)	Spinning 10-min Demand Quantity	600 MW
	GCR 10 Non-Spin (helps meet 4)	Total 10-min Demand Quantity	1600 MW
	GCR 30 (helps meet 3)	Total 30-min Demand Quantity	2400 MW
	RER 90 (helps meet 2)	Total 90-min Demand Quantity	3000 MW
Longer	**RER 240** (helps meet 1)	Total Four-Hour Demand Quantity	3600 MW

In words, this shows that an award of GCR 10-minute spinning reserve contributes to meeting all five of these total day-ahead ancillary service demand quantities in the co-optimized day-ahead market. An award of GCR 10-minute non-spinning reserve contributes to meeting four of these five total day-ahead ancillary service demand quantities; an award of GCR 30-minute reserve contributes to meeting three of these five total timed day-ahead ancillary service demand quantities; and so forth.

To clarify a crucial point: in this graphic, the left-hand slide lists the ancillary service *products*, and the right-hand side lists the multiple *demand* quantities to which they contribute. The demand quantities listed on the right are cumulative, but the individual products on the left are not. In other words, the 1600 MW demand quantity shown for total 10-minute reserve capability (shown in yellow) *includes* the 600 MW demand quantity shown for 10-minute spinning reserve capability (shown in red). And while either the GCR 10-minute spinning reserve *product* or the GCR 10-minute non-spinning reserve *product* can contribute to satisfying the total 10-minute non-spinning reserve *demand*, they are distinct products — and only one, the GCR 10-minute spinning reserve product, can serve the 10-minute spinning reserve demand.

This product substitution structure helps the day-ahead market co-optimize energy and ancillary service costs effectively. In particular, a MWh of the ancillary service capabilities that are typically in relatively less ample supply, such as the fast-responding 10-minute reserve products, can do 'extra duty' by contributing to all five of these ancillary service demand quantities. This tends to reduce the cost to meet all of the system's day-ahead reserve needs to provide a reliable next-day operating plan. As noted previously, the real-time reserve market has used a similar product substitution structure for many years for the reserve capabilities that are designated by the ISO in real-time.

► **Price Cascading.** This product substitution structure has an important implication for pricing. It implies that clearing prices for the ancillary service products with shorter response times will be equal or greater than the clearing prices for the products with longer response times. This property, and the calculation method for these ancillary service product prices, provides the economically-appropriate compensation for each of these five day-ahead ancillary service products.

For example, the clearing price of GCR 10-minute spinning reserve (highest in the hierarchy in the prior graphic) will be greater than or equal to the clearing prices of the four other generation contingency reserve and replacement energy reserve products. And the clearing price of GCR 10-minute non-spinning reserve (second highest in the hierarchy) will be greater than or equal to the clearing prices for the three products associated with longer response times. And so on.

Formally, this property is known as *price cascading*. The economic foundation for this property is the participation payment principle, as discussed earlier in Section 6.3. That principle states that an offer that participates in satisfying multiple requirements should be paid the price (here, as reflected in the marginal cost) of *each* requirement. In this way, the participating offer is compensated for the value it provides, at the margin, by avoiding the procurement of additional (more costly) offers to satisfy each requirement.

Importantly, the price cascading property, and the participation payment principle more generally, are not "double counting" or "double paying" resources for the ancillary services they provide. For example, because of the incremental capability award accounting rules, the additional energy that a resource can deliver (above its day-ahead energy schedule) within 30 minutes, but that it cannot deliver within 10 minutes, does not count toward the demand for total 10-minute reserve. And that incremental GCR 30-minute reserve award is not paid a price applicable to a GCR 10-minute reserve award (which counts toward both the demand for total 10-minute reserve and the demand for total 30-minute reserve).

► **Technical Notes on the Price Cascading.** The new Tariff provisions governing how these day-ahead ancillary service products' clearing prices reflect this price cascading property.[141] To interpret the language in those provisions precisely, here is some additional technical detail.

In the context of generation contingency reserve and replacement energy reserve, each of the five total ancillary service *demand* quantities shown in the product hierarchy graphic above can be interpreted as a requirement, or constraint, for the day-ahead co-optimization process to satisfy. Each of those ancillary service demand quantities will also have a marginal cost. And each of those marginal costs is determined, as usual, by the change in the (dollar-denominated) day-ahead

[141] *See* revised Tariff Sections III.2.6.2(a)(i) through III.2.6.2(a)(v).

market's solution objective with respect to an incremental change (in MWh) in the corresponding ancillary service demand quantity, at the margin. In technical terms, the marginal cost of each ancillary service demand quantity is commonly referred to as the "shadow price" associated with each constraint.

As usual, these marginal cost calculations (at the day-ahead market's optimal solution) are the basis for each day-ahead ancillary service seller's market compensation. However, each generation contingency reserve and replacement energy reserve product (excepting the last, RER 240) contributes to multiple requirements. Thus, to satisfy the participation payment principle, each successful seller of a specific generation contingency reserve and replacement energy reserve product must be compensated for the (avoided) marginal cost of *each* constraint to which it contributes.

Here's how this is implemented, and how it is reflected in the Tariff. In the clearing process, the day-ahead market determines a shadow price (that is, the marginal cost) associated with each ancillary service demand quantity. In Table 7-4, we list on the left each of the five generation contingency reserve and replacement energy reserve product types. In the middle and far-right columns, the abbreviation 'SP' stands for shadow price and 'CP' stands for clearing price. To ensure that each generation contingency reserve and replacement energy reserve product is compensated for the marginal value it provides by satisfying multiple constraints, the clearing price for each product is set as the *sum* of the shadow prices (that is, the sum of the marginal costs) for *each* constraint to which it contributes.

Table 7-4. Price Cascading of Ancillary Service Products Using the Participation Principle

	Day-Ahead Reserve Product	Clearing Price = Sum of Constraint SPs ($/MWh)	Equivalent to: ($/MWh)
[1]	GCR 10 spin	$SP_{TenSpin} + SP_{Tot10} + SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{TenSpin} + CP_{GCR10}$
[2]	GCR 10 nonspin	$SP_{Tot10} + SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{Tot10} + CP_{GCR30}$
[3]	GCR 30	$SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{Tot30} + CP_{RER90}$
[4]	RER 90	$SP_{Tot90} + SP_{Tot240}$	$SP_{Tot90} + CP_{RER240}$
[5]	RER 240	SP_{Tot240}	CP_{RER240}

For example: the RER 240 reserve product contributes to only one ancillary service demand quantity, the demand for total four-hour reserve. Row [5] of Table 7-4 shows that the clearing price for the RER 240 reserve product will be set by the shadow price, or marginal cost, of satisfying the market's total four-hour reserve demand quantity.

Working up the table, the RER 90 reserve product contributes to exactly two ancillary service demand quantities: the demand for total 90-minute reserve and the demand for total four-hour reserve. Row [4] of Table 7-4 shows that the clearing price for the RER 90 reserve product will be set by the *sum* of the shadow price to satisfy the market's total 90-minute reserve demand quantity and the shadow price to satisfy the market's total four-hour reserve demand quantity (to which it also contributes).

And so on. At the top, the GCR 10-minute spinning reserve spin product contributes to all five ancillary service demand quantities shown here. Row [1] of Table 7-4 shows that the clearing price for the GCR 10-minute spinning reserve product will be set by the *sum* of the shadow prices to satisfy each of the market's five reserve demand quantities listed here (to all of which it contributes).

In the Tariff, these clearing prices are written based on the formulas in the far-right column of Table 7-4. In words, each generation contingency reserve and replacement energy reserve product's clearing price is the sum of (a) the shadow price (that is, the marginal cost) of the ancillary service demand quantity with the same response time, and (b) the clearing price for the next lower (that is, longer response time) product within this product hierarchy. Mathematically, the last two columns in Table 7-4 are equivalent, but the nesting structure is written more succinctly using the format in the last column. The Tariff language is constructed similarly.[142]. While technical, this structure of the Tariff language makes explicit the price cascading property that is essential for proper price formation and compensation for these five day-ahead ancillary services.

► **Summary and Implications.** Viewed from a broader perspective, there are three key points from this pricing discussion. First, the pricing and compensation for generation contingency reserve and replacement energy reserve are based on sound economic principles. They are based on the system's marginal cost to satisfy each ancillary service demand quantity, which in turn is based on a corresponding reliability requirement. Furthermore, the compensation satisfies the participation payment principle when products contribute to satisfying multiple requirements simultaneously.

Second, this pricing method will play an important role – indeed, it is economically essential – to ensure that the day-ahead ancillary service market will properly compensate all sellers for the *inter-product opportunity costs* of providing one product, instead of any other. We will show this using several detailed numerical examples of market clearing and pricing with generation contingency reserve and replacement energy reserve, in Section 7.5-7.7 below.

Last, the price formation logic and calculation method (as summarized in Table 7-4) is also used for the reserve products designated by the ISO in its co-optimized real-time market. The economic theory that underlies it is sound, and the price cascading property that results possesses the intuitively clear property that market prices are higher for faster-ramping products that, inherently, have greater value in preserving system reliability. It is also a pricing method that market participants should find familiar, given its continuous use for reserve-energy co-optimization in the ISO's real-time markets for nearly fifteen years.

7.3 Demand Quantities and Resource Capabilities: Historical Data

In this section, we provide estimates of the demand quantities for day-ahead generation contingency reserve and replacement energy reserve, based on operating data for the New England

[142] *See* revised Tariff Sections III.2.6.2(a)(i) through III.2.6.2(a)(v).

system during 2018 and 2019. We also summarize corresponding data on the nominal capabilities of the generation fleet to meet these ancillary service demands.

► **Demand quantities.** The required demand quantities for generation contingency reserve and replacement energy reserve ancillary services vary hourly, based on the system's next-day generation patterns and external interface schedules (as determined, primarily, in the day-ahead market). To estimate the system's demand for these ancillary services on a day-ahead basis, we evaluated data from the day-ahead market outcomes and next-day operating plans in 2018 and 2019. These data include information on the system's projected real-time Operating Reserve requirements for each hour of the next day, and the system's several largest potential single-source supply-loss contingencies for each hour of the next day. The ISO presently determines these values, on a day-ahead basis, during the penultimate unit commitment phase of the day-ahead market.[143]

Table 7-5 provides summary statistics for the estimated hourly day-ahead ancillary service demand quantities for generation contingency reserve and replacement energy reserve. As noted above, these ancillary service demand quantities are cumulative demands and, other than the first (for 10-minute spinning reserve), can be satisfied by multiple generation contingency reserve and replacement energy reserve products.

Table 7-5. Hourly Day-Ahead Ancillary Service Demand Quantity Estimates

		Estimates Based on 2018 Data				
	Ancillary Service	**Minimum**	**5th Percentile**	**Median**	**95th Percentile**	**Maximum**
	Reserve Demand	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	Ten Minute Spinning	475	549	666	783	915
[2]	Total 10 Minute	1,447	1,488	1,584	1,810	2,033
[3]	Total 30 Minute	1,992	2,252	2,389	2,656	2,837
[4]	Total 90 Minute	2,330	2,857	2,995	3,419	3,513
[5]	Total 240 Minute	2,664	3,280	3,613	4,042	4,138
		Estimates Based on 2019 Data				
	Ancillary Service	**Minimum**	**5th Percentile**	**Median**	**95th Percentile**	**Maximum**
	Reserve Demand	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	Ten Minute Spinning	539	554	586	655	754
[2]	Total 10 Minute	1,456	1,496	1,584	1,769	2,038
[3]	Total 30 Minute	2,090	2,264	2,370	2,589	2,878
[4]	Total 90 Minute	2,520	2,873	2,992	3,336	3,589
[5]	Total 240 Minute	2,928	3,322	3,604	3,942	4,223

[143] *See* Day-Ahead Enhancements: Technical Session 1, ISO New England Presentation dated December 5, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/12/20181205-da-enhancements-tech-session-1.pdf, at Slide 29 et seq.

1. Rows [1] of Table 7-5 (one row [1] for 2018 and one row [1] for 2019) indicate the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, which can be satisfied with (only) the GCR 10-minute spinning reserve product. Consistent with new Tariff Section III.1.8.5(a), the data in this row are based to the system's projected hourly next-day Ten-Minute Spinning Reserve Requirement for the New England Balancing Authority Area. Historically, this value ranges from 31 percent to 50 percent of the system's projected hourly next-day Total Ten-Minute Reserve requirement.[144]

2. Rows [2] of Table 7-5 indicate the Day-Ahead Total Ten-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve and GCR 10-minute non-spinning reserve. Consistent with new Tariff Section III.1.8.5(b), the data in this row are based on the projected hourly next-day Total Ten-Minute Reserve Requirement for the New England Balancing Authority Area. That, in turn is based (primarily) on the size of the system's projected largest source-loss contingency.[145]

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 10-minute MWh value shown in row [1] of Table 7-2, which is based on the size of the largest contingency in Table 7-1, Resource A.

3. Rows [3] of Table 7-5 indicate the Day-Ahead Total Thirty-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, and GCR 30-minute reserve. Consistent with new Tariff Section III.1.8.5(c), the data in this row are based on the projected hourly next-day Minimum Total Reserve Requirement for the New England Balancing Authority Area. That, in turn, is based on the size of sum of the system's projected largest source-loss contingency and one-half of the second-largest source loss contingency.

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 30-minute MWh value shown in row [3] of Table 7-2. That is based on the size of the largest contingency in that example, Resource A, plus one-half of the size of the (pre-contingency) second largest contingency, Resource B, shown in Table 7-1.

4. Rows [4] of Table 7-5 indicate the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, and RER 90-minute reserve. Consistent with new Tariff Section III.1.8.5(d) and NERC standard BAL-002-3 as referenced therein, the data in this row are based on the projected sum of the system's largest and second-largest source-loss contingencies in the next-day operating plan for the New England Balancing Authority Area.

[144] *See* Brandien Testimony at pp. 9-10.

[145] The Total Ten-Minute Reserve Requirement data summarized here also include a non-performance adjustment, consistent with the ISO's Operating Procedures. *See* Brandien Testimony at p. 9.

In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 90-minute MWh value shown in row [4] of Table 7-2. That is based on the sum of the sizes of the two largest contingencies in that example, Resource A and Resource B.

5. Rows [5] of Table 7-5 indicates the Day-Ahead Total Four-Hour Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, RER 90-minute reserve, and RER 240-minute reserve. Consistent with new Tariff Section III.1.8.5(e) and NPCC Regional Reliability Reference Directory No. 5 as referenced therein, the data in this row are based on the projected sum of the system's largest, second-largest, and one-half of the third-largest source loss contingencies in the next-day operating plan for the New England Balancing Authority Area.

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 240-minute MWh value shown in row [5] of Table 7-2. That is based on the size of the largest contingency, Resource A, plus the size of the second largest contingency, Resource B, plus one-half of the size of the third largest contingency (written in Table 7-1 as the post-contingency second contingency loss), Resource C.

As the variation in the hourly data in Table 7-5 indicates, the actual MWh values of each of these ancillary service demand quantities are dynamic – they vary from hour to hour, and day to day. Figure 7-2 below shows the underlying hourly values summarized in Table 7-5, rows [2]-[5], for 2019. The periodic 'upward' spikes correspond to hours when either large generation assets (that constitute a single source-loss) were scheduled to operate at exceptionally high-levels of output, or an external interface transmission (that constitutes a single source loss of supply) was scheduled at unusually high net import levels during the next operating day. The 'downward' drops correspond to periods when one of the system's (three) normally largest contingencies was not scheduled to operate (*e.g.,* a scheduled outage).

The close time-based alignment of the spikes (both upward and downward) in these data reflect that these are cumulative demand quantities. Therefore, an increase in the size of the first-contingency source loss (determining the total 10-minute reserve demand quantity) will increase all others demand quantities as well, and vice versa.

Overall, while these ancillary service demand quantities are dynamic, they are not nearly as volatile as the energy gap data that determine the demand for energy imbalance reserve, as demonstrated in comparison with Figure 6-1 in Section 6.1.2.

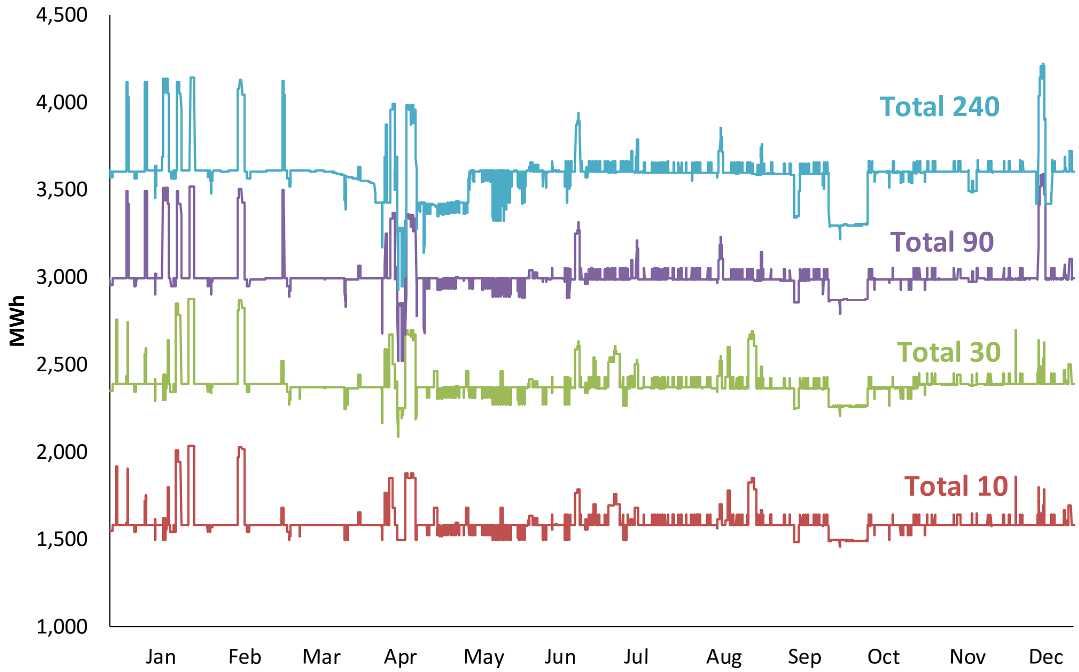

Figure 7-2. Hourly Estimated Day-Ahead Ancillary Service Demand Quantities, 2019

► **Notes and implications.** Two points on these data merit note. First, these ancillary service demand quantities are in addition to the energy imbalance reserve demand quantity needed to satisfy the forecast energy requirement. As noted, energy imbalance reserve serves to meet the system's *expected* (forecast) energy demand; the ancillary service demand quantities for generation contingency reserve and replacement energy reserve serve a wholly different purpose, which is to address *uncertainties* that require additional supplies of energy – that is, in addition to the forecast – in order to operate the system reliably during the next operating day.

Second, the data in Table 7-5 and Figure 7-2 do not include ancillary service demand quantity adjustments to account for load forecast error. In practice, load forecast error is normally comparatively small, relative to the system's overall day-ahead ancillary service demands to address potential supply loss uncertainties (*i.e.,* contingencies) shown above. For example, the mean absolute error of the day-ahead load forecast was just 275 MW and 246 MW in 2018 and 2019, which was just under two percent (as a percent of actual load).[146] Demand quantities to address load-forecast error are most cost-effectively implemented with dynamic calculations, inasmuch as

[146] ISO New England calculations from system operating data.

energy demand uncertainty is greater at certain times of the day and in certain seasons, and can depend on the weather forecasts (*e.g.,* clear skies may present more predictable solar output than intermittently partly-cloudy days, and such). For the total 90-minute and total 240-minute ancillary service demands combined, recent analyses suggest that effective quantity adjustments to account for load forecast error may likely be only a few percent of the value of the load forecast itself.[147]

► **Resource capabilities.** As noted previously, the current energy-only day-ahead market does not procure any of the ancillary services that can satisfy the reliability-based ancillary-service demand quantities shown in Table 7-5 and Figure 7-2. Fortunately, however, the New England system has ample quantities of resources with the ramping capabilities to meet these demands today – that is, if they have fuel to operate when called upon.

Table 7-6 shows the nominal capabilities of all online and offline resources that can satisfy the various ancillary service demand quantities for generation contingency reserve and replacement energy reserve. We use the term 'nominal,' or alternatively the term 'apparent reserve,' because these calculations assume the resources have energy supply arrangements in place to operate (even if they did not expect to be needed that day). More specifically, these data represent the calculated ramping capability, based on resources' physical operating parameters in the ISO's databases, given their actual energy schedules during 2019. We performed these calculations hourly for each resource in the system (during 2019), and summarize the hourly averages in Table 7-6.

The first row is the average energy ramping capability of all units that were offline, evaluated hour-by-hour during 2019, and accounting for their notification and (cold) startup time requirements. The second row is the average energy ramping capability of all units above their day-ahead market energy schedules, evaluated hour-by-hour for 2019, within the timeframes shown.

Table 7-6 Hourly Average Day-Ahead Ramping (Apparent Reserve) Capability, 2019

	State	10-minute	30-minute	90-minute	240-minute
[1]	Offline	3,886	4,897	5,557	6,434
[2]	Online	783	1,079	1,181	1,207
[3]	**Total**	**4,669**	**5,976**	**6,738**	**7,641**

[147] *See* Energy Security Improvements: Market-Based Approaches, Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion, Presentation to NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_ii_esi_rer_goal2_accounting_for_load_forecast_error.pptx, at Slides 18-22.

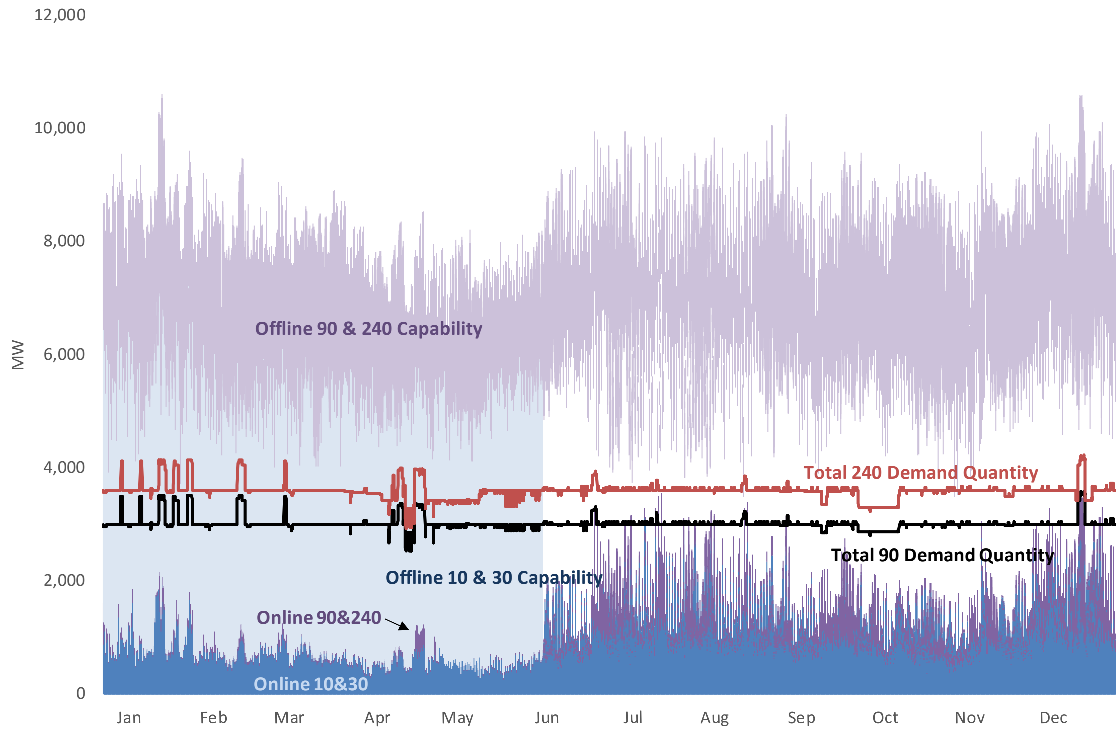

Figure 7-3. Hourly Estimated Day-Ahead Ancillary Service Capabilities, 2019

Overall, these data indicate that the New England fleet's nominal ramping capabilities and capacity amply exceeds the amounts needed to simultaneously satisfy energy demand (as scheduled day-ahead) and to satisfy the new day-ahead ancillary service demand quantities. That observation is more directly evident in Figure 7-3. It shows these same nominal (apparent reserve) capabilities at the hourly level during 2019, superimposed with the total 240-minute and total 90-minute ancillary service demand quantities shown previously in Figure 7-2.

In this figure, the lowest series (in dark blue and purple) show the system's online and unloaded total ramping capability. These values are relatively modest, from 700 MW (for online 10-minute reserve capability) to 1200 MW (for online 240-minute reserve capability), as shown in row [2] of Table 7-6. This reflects, in part, the limited requirement for spinning reserve (as a share of total reserve) in New England (*see* Table 7-5, row [1]). In contrast, the existing generation fleet's ability to provide offline reserve capability is substantial, averaging approximately 5 GW for reserves within thirty minutes and 6.5 GW within four hours (240 minutes), as summarized in row [1] of Table 7-6. These values substantially exceed, normally by a factor of two and often more, the corresponding ancillary service demand quantities.

► **Implications.** The main point of these data is straightforward. In New England, the generation fleet has ample nominal – that is, *apparent* – capability to fully satisfy the system's ancillary service needs and provide for a reliable next day operating plan. However, that capability is of little use if the resources in Table 7-6 have not made the necessary arrangements for fuel in advance of the operating day.

As highlighted in Section 2.7 earlier, the resources that are nominally capable of enabling the system to close an unexpected energy gap frequently have no reason to *expect* to operate the next day, as they are needed precisely when unanticipated events occur. And, also as explained in Section 2, under the current market construct these resources have inefficiently low incentives to make energy supply (*i.e.,* fuel) arrangements in advance of the operating day.

Stated simply, the New England region does not need more generating resources to address its fuel security challenges today. It needs a market appropriately designed to ensure that the resources already here will have strong financial incentives to undertake energy supply arrangements when it would be cost-effective from society's standpoint for the resource to do so. For the reasons explained in Sections 4 and 5, the Energy Security Improvements provide such a market design.

7.4 Tariff Provisions

In this section, we describe various rules governing day-ahead co-optimization of energy and ancillary services, pricing and demand quantities for generation contingency reserve and replacement energy reserve, and their associated new Tariff provisions in this filing.

► **Co-optimization-related new tariff provisions.** The primary day-ahead market co-optimization provisions are contained in new Tariff Section III.1.10.8(a)(ii), revising existing SectionIII.1.10.8(a). These revisions extend the existing energy-only day-ahead market reflected in Section III.1.10.8(a) to a day-ahead market that clears both energy and ancillary services, including generation contingency reserve and replacement energy reserve.

These and related provisions that apply generally to the co-optimization of all new day-ahead ancillary services, with one exception discussed next, are summarized in Sections 6.4.2 and 6.4.3. That discussion applies similarly to the co-optimization for generation contingency reserve and replacement energy reserve.

Limitations. The final portion of new Section III.1.10.8(ii) contains two limitations on the clearing process. The first, in enumerated item (1) in the last paragraph of new Section III.1.10.8(ii), is only applicable to generation contingency reserve and replacement energy reserve (that is, it does not apply to energy imbalance reserve). This limitation requires, by way of reference to existing Tariff Section III.1.7.19.1, that to receive a day-ahead award for generation contingency reserve or replacement energy reserve, a resource must satisfy various technical criteria necessary to provide real-time Operating Reserves. The purpose of this limitation is to ensure that the resources scheduled in the day-ahead market for generation contingency reserve and replacement energy reserve (and that the ISO expects to rely upon in its next-day operating plan to respond as directed in the event of an unanticipated supply loss, as discussed in Section 7.2) meet various pre-existing criteria for real-time reserves related to communications, dispatchability, sustainability, and so forth.

The second limitation in the final portion of new Section III.1.10.8(ii), in enumerated item (2), applies only to energy imbalance reserve as discussed in Section 6.4.2 and, in greater detail, Section 6.4.3.

► **Demand quantities.** For clarity, several new Tariff provisions use the more economically-precise term "Demand Quantity" to reference numerical values that, in more common parlance, are referred to as "requirements." Specifically, new Section III.1.8.5 defines the Day-Ahead Ancillary Service Demand Quantities, consistent with the foregoing explanations in Section 7.2.2. Of note:

- Sections III.1.8.5(a)-(c) define the Day-Ahead Ancillary Service Demand Quantities that can be satisfied by (only) the three generation contingency reserve products. These definitions expressly set the day-ahead market's demand for these three capabilities based on the corresponding projected real-time requirements for Operating Reserves for the same operating hour of the next day. Those, in turn, are determined by the reliability standards applicable to ten- and thirty-minute reserves and described in detail in the Brandien Testimony.[148]

- Section III.1.8.5(d) defines the Day-Ahead Total Ninety-Minute Reserve Demand Quantity. This has two components, one related to unanticipated changes in supply and the other to unanticipated changes in demand. The first component expressly sets the set the day-ahead market's demand for this capability based on the projected requirements to satisfy the NERC BAL-002-3 standard for contingency reserve restoration during the applicable hour of the operating day. That, in turn, is based on the system's (two) largest supply loss contingencies during the corresponding hour, as illustrated above in Section 7.2.3 and described in greater detail in the Brandien Testimony.[149] The second component provides an allowance for load forecast error, for the reasons discussed in Sections 7.1 and 7.2.1 above ("Reserves for load forecast error").

- Section III.1.8.5(e) defines the Day-Ahead Total Four-Hour Minute Reserve Demand Quantity. This has the same two component-structure as the preceding definition, and mirrors that provision with the exception that the associated reliability standard is contained within NPCC Regional Reliability Reference Directory No. 5.[150]

► **Prices and price cascading.** The pricing provisions applicable to GCR and RER are contained in new Tariff Sections III.2.6.2(a)(ii)-(v). These closely match the supporting design details, and reflect the economic logic and rationales, discussed in Section 7.2.3 above.

[148] *See* Brandien Testimony at pp. 6-17.

[149] *See* Brandien Testimony at pp. 6-17.

[150] *See* Section 7.2.3 and Brandien Testimony at pp. 6-17.

In particular, each price in Sections III.2.6.2(a)(ii)-(v) is determined by the marginal (that is, the incremental) cost of the corresponding Day-Ahead Ancillary Service Demand Quantity, plus the clearing price of the specific Day-Ahead Ancillary Service Demand Quantity that is one step “lower” in the product substitution hierarchy. In this way, the pricing rules expressly and transparently incorporate the price cascading logic described in Section 7.2.3.

Note that each price in Sections III.2.6.2(a)(ii)-(v) is associated with a specific demand quantity, not with a specific generation contingency reserve or replacement energy reserve product. The assignment of prices to product awards is provided for separately in the settlements provisions in new Section III.3.2.1(q)(1), discussed below.

► **Cleared quantities (Obligations).** New Tariff Sections III.3.2.1(a)(2)(i)-(v) govern market participants’ cleared quantities of generation contingency reserve and replacement energy reserve, here defined as Obligations (“Obligations” as used in this portion of the Tariff refers to quantities for settlement, and are units of MWh, not dollars).

As a general matter, the language used in new Section III.3.2.1(a)(2) reflects the market design property that market participants’ energy call option offers are the *inputs* into the co-optimized day-ahead market clearing process, and the different ancillary service products (*i.e.,* obligations) are the *outputs* of the market clearing process (*see* Section 4.1).

There is a careful accounting of obligations and the product substitution hierarchy in this section to ensure that each Obligation receives the correct payment (the payments being provided in Sections III.3.2.1(q)(1)(i)-(v) and Section III.3.2.1(q)(2)(ii)). This reflects the incremental capability accounting logic and the product substitution hierarchy discussed in Section 7.2.3. Explained directly:

- Section III.3.2.1(a)(2)(i) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation. This is the highest product in the generation contingency reserve and replacement energy reserve product hierarchy.

- Section III.3.2.1(a)(2)(ii) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, *except* it then expressly excludes any MWh that already have a Day-Ahead Ten-Minute Spinning Reserve Obligation. This exclusion is necessary because: (*a*) Day-Ahead Ten-Minute Spinning Reserve, being higher on the product substitution hierarchy, also contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity (*see* Section 7.2.3); and because (*b*) the MWh that receive a Day-Ahead Ten-Minute Spinning Reserve Obligation will be paid the appropriate price, given the price cascading design, for that Day-Ahead Ten-Minute Spinning Reserve Obligation in the settlement provision in Section III.3.2.1(q)(1).

- In a similar manner, Section III.3.2.1(a)(2)(iii) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Total Thirty-Minute Reserve Demand Quantity shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation, *except* it then expressly excludes any MWh that already have a Day-Ahead Ten-Minute Spinning Reserve Obligation *or* a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation. This exclusion is necessary because: (*a*) both Day-Ahead Ten-Minute Spinning Reserve and Day-Ahead Ten-Minute Non-Spinning Reserve, being higher on the product substitution hierarchy, also contribute to satisfying the Day-Ahead Total Thirty-Minute Reserve Demand Quantity (*see* Section 7.2.3); and because (*b*) the MWh that receive a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation will be paid the appropriate price, given the price cascading design, for those awards in the settlement provision in Section III.3.2.1(q)(1).

- The provisions in Sections III.3.2.1(a)(2)(iv) and III.3.2.1(a)(2)(v) are structured similarly for Day-Ahead Ninety-Minute Reserve Obligations and Day-Ahead Four-Hour Reserve Obligations, for the same reasons.

► **Reserve Constraint Penalty Factors.** The economic logic, interpretation, and purpose of Reserve Constraint Penalty Factors are discussed in detail in prior Section 6.4.3. As noted there, each reserve-related constraint in a co-optimized market requires a Reserve Constraint Penalty Factor.

New Sections III.2.6.2(b)(i)-(v) define the Reserve Constraint Penalty Factors applicable to the day-ahead co-optimized market's reserve-related constraints that can be satisfied with generation contingency reserve, replacement energy reserve, or both. In these provisions, the Reserve Constraint Penalty Factors are expressly associated to the corresponding (exogenous) Day-Ahead Ancillary Service Demand Quantity that defines how much should be procured to satisfy the applicable constraint.

Since the concept and purposes of Reserve Constraint Penalty Factors is discussed in detail above (*see* Section 6.4.3), here we limit our discussion to the rationale and reasoning for the specific numerical values specified in new Sections III.2.6.2(b)(i)-(v).

- Section III.2.6.2(b)(v) sets the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity at $100/MWh.

  To determine an appropriate Reserve Constraint Penalty Factor for this purpose, we used the model developed for the Impact Assessment to evaluate the maximum "re-dispatch" costs that would be incurred to enable that model of the co-optimized day ahead market to satisfy the full Day-Ahead Total Four-Hour Reserve Demand Quantity, for various scenarios evaluated in the Impact Assessment. The concept is that it would be undesirable to set a Reserve Constraint Penalty Factor too low, as that would cause frequent "artificial" shortages of replacement energy reserve. Such an outcome would undermine the reliability objectives and goals of procuring replacement energy reserve to meet the next-day operating plan's requirements.

Table 14 in the Impact Assessment summarizes the results of this analysis, for the three central cases evaluated. It shows that with a Reserve Constraint Penalty Factor set at $100/MWh (as was used to produce the results in that table), the system as modeled is able to satisfy the full Day-Ahead Total Four-Hour Reserve Demand Quantity between 98% and 100% of the time, depending upon the scenario. That is, shortages of this ancillary service capability would be highly infrequent. Other analyses (not reported in the Impact Assessment) using higher Reserve Constraint Penalty Factor test values (up to $500/MWh) did not show appreciable further reductions to the low frequencies of reserve shortages evident in Table 14.

Ultimately, as the ISO gains operating experience with this co-optimized day-ahead energy and ancillary service design, if we observe shortages of replacement energy reserve then the ISO can evaluate the causes and consider changes to this Reserve Constraint Penalty Factor value at a future date if circumstances warrant. In that way, with the benefit of experience and additional data, the value of the Reserve Constraint Penalty Factor can be more finely tuned, if necessary, to ensure the system does not experience "artificial" shortages of replacement energy reserve as a result of an Reserve Constraint Penalty Factor that is set too low.

- Section III.2.6.2(b)(iv) sets the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity at $250/MWh. This is based on the Commission-approved Reserve Constraint Penalty Factor currently applicable to the Total Reserve Requirement (including Replacement Reserve), which is enforced in the ISO's real-time dispatch.

  The Replacement Reserve was added to the real-time market in 2013.[151] It results in an additional quantity of Thirty Minute Operating Reserve being procured in the real-time market. This level of reserves was added, in part, to address similar concerns to those that will be addressed by the 90-minute replacement energy reserve product in the day-ahead market. Specifically, in its filing on the real-time Replacement Reserve, the ISO indicated that it "can maintain a quantity of replacement reserves . . . for the purposes of meeting the NERC requirement to *restore its total system TMR* [Ten-Minute Reserve] Requirement."[152] Importantly, the ISO performed simulations at the time that showed that $250/MWh is a reasonable indicator of the maximum redispatch cost for incremental reserve capability above the Total Thirty-Minute Requirement. In practice, violations of this Replacement Reserve component of the Total Thirty-Minute Requirement in the real-time market (indicating a redispatch cost to satisfy it in excess of $250/MWh) have been infrequent events.[153]

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[151] *See* Revisions to Market Rule 1 to Establish a Reserve Constraint Penalty Factor for Replacement Reserve Requirement, FERC Docket No. ER13-1736 (filed June 20, 2013), accepted by Letter Order dated August 15, 2013.

[152] *See id*., Joint Testimony of Robert G. Ethier and Christopher A. Parent, at p. 7 (emphasis added).

[153] Calculations based on the ISO's dispatch system data show that in 2018 and 2019, such violations occurred approximately 0.025 percent – that is, 2.5 hundredths of one percent – of the time.

On that basis, we have selected a $250/MWh Reserve Constraint Penalty Factor for the day-ahead Total Ninety-Minute Reserve Demand Quantity. As noted above, as the ISO gains operating experience with this co-optimized day-ahead energy and ancillary service market, the ISO can evaluate and consider changes to this Reserve Constraint Penalty Factor value at a future date if circumstances warrant. The infrequent violations of the Replacement Reserve component of the Total 30-Minute Requirement in the real-time market suggest that a $250/MWh for the 90-minute reserve capability (a product that should be in greater supply than 30-minute reserves in real-time) will not be systematically too low and will not result in frequent "artificial" shortages of replacement energy reserves.[154]

- Sections III.2.6.2(b)(i)-(iii) define the Reserve Constraint Penalty Factors applicable to the Day-Ahead Ancillary Service Demand Quantities that can be satisfied by only the three generation contingency reserve products. These are set, by reference to Section III.2.7A, to the corresponding Reserve Constraint Penalty Factors applicable to the analogous real-time Operating Reserve requirements for Ten-Minute Spinning Reserve, Ten-Minute Reserve, and the Minimum Total Reserve.

  The rationale for using the same Reserve Penalty Constraint Factors in the day-ahead and the real-time market for the analogous Demand Quantities (née requirements) is so that the day-ahead markets will send the same reserve shortage price signal if that shortage is anticipated by (that is, occurs in clearing) the day-ahead market. By doing so, the day-ahead market will signal the full value of actions that market participants may be able to take to help avoid, or reduce the magnitude of, a potential real-time reserve shortage that signals heightened reliability risks.

► **Settlements of generation contingency reserve and replacement energy reserve obligations.** Recall from Section 4 that market participants with cleared energy call option offers have two settlements associated with their energy call options. The first is a credit, at the market clearing price of the ancillary service product for which the energy option was cleared. The second is a charge, or the option close-out, which is equal to the real-time LMP less the strike price (but not less than zero). *See* examples (a) through (j) in Section 4.3.

The new Tariff provisions provide that each MWh of a seller's obligation for a generation contingency reserve or replacement energy reserve product will receive a payment at the corresponding products' day-ahead clearing price, and the corresponding option close-out charge.

- New Sections III.3.2.1(q)(1)(i)-(v) provide for the seller's credit, stipulating that each MWh of a generation contingency reserve or replacement energy reserve obligation will be paid the applicable day-ahead clearing price for the corresponding generation contingency reserve and replacement energy reserve product.

[154] For context, the Impact Assessment analysis of the co-optimized day-ahead market modeled a single replacement energy reserve product, more closely modeling the four-hour product than the ninety-minute product. As a result, this analysis was not able to directly inform the maximum redispatch cost for the 90-minute requirement.

- New Section III.3.2.1(q)(2)(ii) provides for the seller's option close-out charge. It stipulates that each MWh of a generation contingency reserve or replacement energy reserve obligation will be charged the energy option close-out amount. The option close-out amount is based on the Real-Time Hub Price and the energy option strike price, as explained in Section 4.3.2 (on option settlement location) and Section 4.5.2 (on strike prices).

► **Cost allocation for generation contingency reserve and replacement energy reserve.** The allocation of net costs and credits for generation contingency reserve and replacement energy reserve is contained in new Section III.3.2.1(q)(3). Like the energy imbalance reserve credits and charges to sellers, the generation contingency reserve and replacement energy reserve cost allocation has two components. One is the cost allocation (a charge) associated with the day-ahead generation contingency reserve and replacement energy reserve prices paid to sellers. This is provided in Section III.3.2.1(q)(3)(i). The second is the close-out offset (a credit) associated with the close-out of these sellers' day-ahead energy options. This is provided in Section III.3.2.1(q)(3)(ii).

These charges and credits are allocated to the system's real-time load, on the beneficiaries-pay principle. The reasoning is that the reserve requirements that enable the system to cover an unanticipated energy supply loss ensure the power system is prepared to reliably deliver energy to load *in real-time*. Real-time load is, therefore, ultimately the beneficiary of the costs incurred to satisfy the system's generation contingency reserve and replacement energy reserve requirements.

Section III.3.2.1(q)(3) contains an exclusion from these credit and charge allocations for the real-time load of storage resources (*i.e.,* Storage DARDs), for the reasons discussed in Section 6.6.2 above.

7.5 Example 4: Energy and One Ancillary Service Co-Optimization

To illustrate the pricing and clearing concepts of the prior sections, in this section and the next we provide a series of numerical examples. The purpose of these examples is to illustrate the pricing and clearing concepts with a co-optimized day-ahead energy and ancillary services market.

We start with a pair of examples in which we assume the market clears energy and a single generation contingency reserve product. For simplicity, we will assume in these first examples that energy demand clears at the forecast energy requirement, and there is no energy imbalance reserve (nor a need for it). We use these simplified settings in order to make transparent several important pricing properties.

In later examples in Section 7.6, we will build on these first two simple examples and examine situations with energy and multiple ancillary service products, and how their prices cascade. In Section 7.7, we then provide more involved examples involving energy imbalance reserve, the forecast energy requirement, and generation contingency reserve clearing simultaneously.

7.5.1 Example 4-A: Incorporating Opportunity Costs in the Day-Ahead LMP

This example considers the co-optimization of energy and generation contingency reserve when suppliers provide offers for each service. The main point of this first pair of examples is to show how the market clearing prices account for resources' inter-product opportunity costs in an economically appropriate way.

In particular, in the first example, we will see that energy option offers and the clearing price for generation contingency reserve can impact the day-ahead LMP. It does so in a way that differs from the outcomes that are possible in the existing real-time co-optimized energy and reserve market. The reason for this difference is that there are offers from suppliers in the day-ahead co-optimized market, whereas there are no offers to sell reserves in the real-time market.

Some useful notes on terminology: because there is a single generation contingency reserve product in this example and the next, we can interpret that term generically; that is, in this example, we do not specify whether it is for 10-minute spinning reserve, 10-minute non-spinning reserve, or 30-minute reserve. In addition, we will use the term 'reserve clearing price' (or RCP) to denote the market-clearing price for this day-ahead ancillary service.

Last, in both this example and the next, we will assume energy demand is inelastic, or non-price sensitive, and equal to the forecast energy demand. Treating energy demand as "fixed" will enable us to focus on the pricing impacts of resources' supply offers and their opportunity costs. In later examples, we will re-introduce priced demand bids that will further impact how the market clears.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, examined previously in Examples 3-A and 3-B in Section 6.3. For convenience, their energy supply offer prices and quantities (*i.e.,* resource capacities), and their energy option offer price and quantities, are reproduced in Table 7-7 below. Note that, as before, the generators are listed in ascending order of their energy offer price.

In this example, we have changed two things from the prior Example 3-B. First, energy demand is assumed be fixed at 720 MWh, as shown in row [10] of Table 7-7. Second, we assume there is an ancillary service demand quantity for generation contingency reserves of 190 MWh. *See* row [10] of Table 7-7. This is the only reserve product; that is, we do not model energy imbalance reserve or the forecast energy requirement here.

► **Market outcomes.** The market-clearing outcomes are summarized in the last two columns of Table 7-7. Generators A through D clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators D through F clear generation contingency reserve for a total of 190 MWh, equal to the ancillary service demand. The marginal offers for energy and for generation contingency reserve are those of Generator D and Generator F, respectively; for reference, these marginal offers, and the associated awards, are shaded in light orange in Table 7-7.

Table 7-7. Assumptions and Market Outcomes for Example 4-A								
		Supply Offer Assumptions					**Day-Ahead Outcomes**	
		Energy Supply Offers		**Energy Option Offers**			**Market Awards**	
		Price	Quantity	Price	Quantity		Energy	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)		(MWh)	(MWh)
[1]	A	$0	300				300	-
[2]	B	$10	150				150	-
[3]	C	$36	150	$2.59	100		150	-
[4]	D	$42	200	$2.59	100		120	80
[5]	E	$60	200	$5.05	90		-	90
[6]	F	$72	50	$5.54	50		-	20
[7]	G	$78	50	$5.82	50		-	-
[8]	H	$210	150				-	-
[9]	**Totals**		**1250**		**390**		**720**	**190**
							Day-Ahead Outcomes	
		Demand Assumptions (MWh)					**Clearing Prices ($/MWh)**	
		Energy Demand		GCR Demand			LMP	GCR
[10]	**Totals**		**720**		**190**		**$44.95**	**$5.54**

In this example, the cleared awards illustrate a property we'll call *stack separation.* That is, the resources with the lowest energy offer prices all clear for energy. These are Generators A through D. The resources that clear for reserve all have (equal or) higher energy offer prices. These are generators D through F. This mirrors the outcomes that are commonly observed in the real-time energy and reserve market, where the lowest-cost resources clear for energy, and higher cost resources remain in reserve.

As usual, it is helpful to interpret the market outcomes and clearing prices graphically. Figure 7-4 shows the supply and demand diagram for the assumptions and results in Table 7-7. The supply offers of Generators B, C, and D, which span the range where the market clears, are shown in the ascending stair-step supply 'curve' in blue. The energy call option offer prices for Generator D's remaining capacity (that is, its capability not cleared as energy), for Generator E, and for Generator F are shown in the green stair-step generation contingency reserve supply curve.

Note that, like the figures in Section 6 earlier, the supply curve of energy option offers is drawn starting from the quantity of energy cleared in the market, here 720 MWh. That is, in this figure, energy demand is represented by the vertical line at 720 MWh. The demand for generation contingency reserve, which is an additional 190 MWh, is drawn along the horizontal axis starting from the point where energy supply and demand clear and extending to (720 MWh + 190MWh) = 910 MWh.

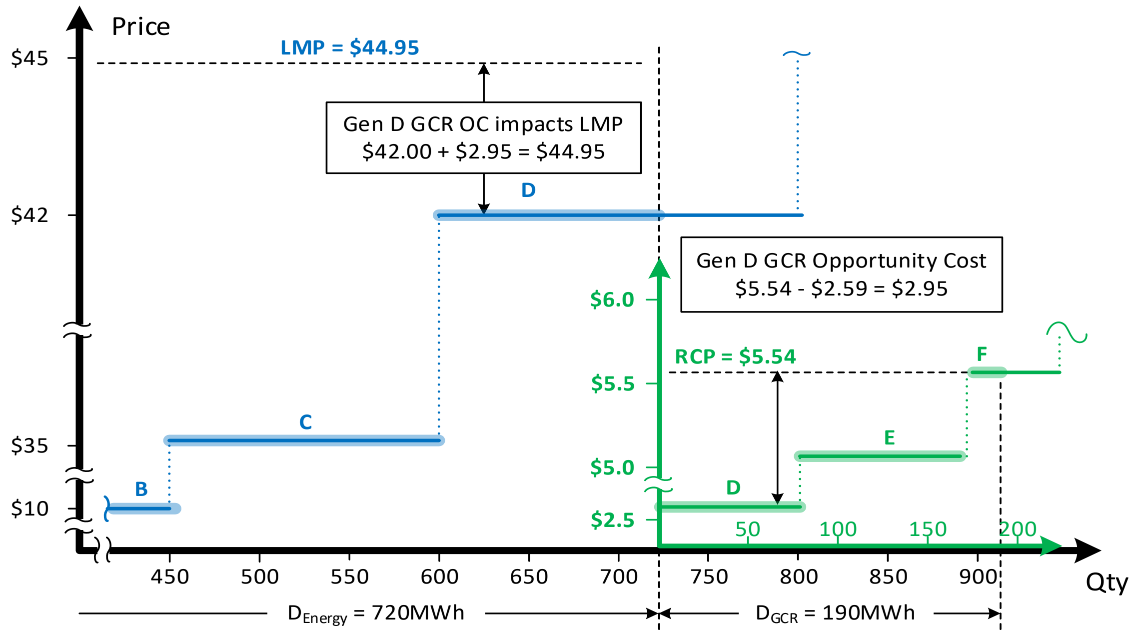

Figure 7-4. Market Clearing Outcomes for Example 4-A

► **Clearing prices.** The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available. Note that at this price, all resources with cleared energy call option offers are willing to accept that price or less; and all generators without cleared energy call option offers, and that did not earn greater profit clearing for energy, are not willing to accept that price.

What is the day-ahead LMP? Consider the marginal cost of serving another unit of energy. In Figure 7-7, Generator D is the marginal supplier of energy. However, it is also providing reserves with the full balance of its capability. Thus, to provide one more MWh of energy from Generator D, the amount of reserves from Generator D would have to be reduced by one MWh. Consequently, one additional MWh of reserves is required and would come from Generator F – the marginal resource for reserve. That additional cost of reserve must be accounted for in determining the marginal cost of serving energy demand.

Table 7-8 summarizes these calculations. Row [1] shows that the additional MWh of energy from marginal Generator D costs $42/MWh, its energy offer price. That reduces the system's purchase of generation contingency reserve from Generator D, a savings of $2.59/MWh, its energy option offer price. *See* row [4]. To continue to satisfy the generation contingency reserve demand of 190 MWh, we now must procure another MWh of generation contingency reserve from Generator F, the marginal resource for reserve. As shown in row [5], that cost is $5.54/MWh, its energy option offer price. Putting all the pieces together, the marginal cost to serve another unit of energy demand is $44.95/MWh, as shown in row [6]. Therefore, the day-ahead LMP is $44.95/MWh.

Table 7-8. Day-Ahead LMP Calculation for Example 4-A

	Change in Total (Production) Costs for One More MWh of Energy Demand		
[1]	+ 1 MWh of energy from Generator D	$42.00	*Energy offer price of marginal Gen D*
[2]			*(results in one less MWh of GCR from Gen D)*
[3]	"Re-dispatch" GCR		
[4]	- 1 MWh of GCR from Generator D	($2.59)	*"Savings" from one less MWh of GCR from Gen D*
[5]	+ 1 MWh of GCR from Generator F	$5.54	*Option offer price to replace the GCR MWh from Gen F*
[6]		**$44.95**	*Marginal cost of energy (LMP)*

Note that, in Figure 7-4, this LMP is *higher* than the marginal energy supply offer price (that is, higher than Generator D's offer of $42/MWh). Thus, with co-optimization of energy and reserve, the LMP may not be set 'at' any resource's energy supply offer price. Rather, it may be set based on the offer prices of *two* marginal offers, one for energy supply and the other for energy options.

Does this energy price clear the market? Yes. At the day-ahead LMP of $44.95/MWh, all suppliers that cleared for energy are willing to accept that price or less; and no supplier that did not clear for energy would be willing to accept that price.

► **Prices and opportunity costs.** These prices have an important economic interpretation: they reflect marginal generator D's *opportunity costs* of supplying energy, rather than reserve.

To see this, notice that Generator D is more profitable providing reserve instead of energy. Its profit (per MWh cleared) providing reserve is the difference between the reserve clearing price (of $5.54/MWh) and Generator D's energy option offer price (of $2.59/MWh; see row [4] of Table 7-7). This difference, of $5.54/MWh – $2.59/MWh = $2.95/MWh, is Generator D's opportunity cost of being economically cleared for energy, instead of selling (additional) generation contingency reserve.

In order to make Generator D indifferent as to whether it supplies energy or reserve, this energy opportunity cost is incorporated *into* the LMP. That is, the day-ahead LMP is the sum of marginal energy supplier Generator D's energy offer price of $42/MWh and its energy opportunity cost of $2.95/MWh: $42/MWh + $2.95/MWh = $44.95/MWh.

Importantly, this opportunity cost perspective aligns perfectly with the method of calculating clearing prices based on the system's marginal costs to procure incremental demand. We will see this property frequently in later examples; it is a fundamental property of economically-appropriate price signals in an efficient, multi-product market.

► **Main points.** There are three points to note from this Example 4-A. First, the day-ahead LMP reflects the marginal cost of serving energy demand, consistent with economic principles. This marginal cost includes the *inter-product opportunity cost* of not supplying additional reserve that is incurred here by the marginal unit for energy.

That is a fundamental and critical element of sound market design in a multi-product market. To see why, consider what happens if the market clearing prices did not make a marginal supplier (of either product) indifferent between its cleared awards and an alternative set (any alternative set) of quantities. In that perverse situation, the marginal supplier would be incented to distort its offer prices to clear more of the product that provides it with a higher profit, and less of the product that does not. That distorted behavior would force the market to make up for the reduced supply of the latter by clearing more offers for it from other suppliers that have truly higher costs. And that distortion begets another in the same way, and so on. In summary, if prices do not properly compensate for sellers' opportunity costs in a multi-product market, it can undermine the efficiency and cost-effectiveness of the entire competitive market.

Second, in this example, the marginal energy supplier's opportunity cost is incorporated "inside" the day-ahead LMP. In later examples, when we add the forecast energy requirement and energy imbalance reserve, we will see that again the market must compensate the marginal energy supplier for its opportunity cost of not selling (additional) reserve. However, instead of incorporating that opportunity cost into the LMP, it will (often) be incorporated into the Forecast Energy Requirement Price instead. That is, in more general cases, the inter-product opportunity cost will be "outside" the LMP, and in the Forecast Energy Requirement Price instead. This will occur because the opportunity cost can arise for the physical supply resource that is marginal for satisfying the next-day's forecast energy requirement, not only the day-ahead market's bid-in energy demand. (Look for this in Examples 6-A and 6-B in Section 7.7 ahead).

Third, this property of the co-optimized day-ahead market specifically motivated the Tariff revisions in new Section III.2.6.1(a), which (as revised) provide that the detailed calculations of the LMP can account for the fact that the (marginal) cost of serving incremental energy demand can depend on ancillary services' offer prices as well.

7.5.2 Example 4-B: Incorporating Opportunity Costs in the Day-Ahead Reserve Price

In Example 4-A, we showed that the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to energy suppliers. However, that need not be the case. In this next Example 4-B, we show the reverse may also occur: the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to ancillary service suppliers.

For convenience, the revised energy supply offer prices and quantities (*i.e.,* resource capacities), and the energy option offer price and quantities, for all eight Generators A through H are reproduced in Table 7-9 below, with the change to Generator D as an 'energy-only' resource.

Note that, as before, the generators are listed in ascending order of their energy offer price.

Table 7-9. Assumptions and Market Outcomes for Example 4-B

		Supply Offer Assumptions				Day-Ahead Outcomes	
		Energy Supply Offers		Energy Option Offers		Market Awards	
		Price	Quantity	Price	Quantity	Energy	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300			300	-
[2]	B	$10	150			150	-
[3]	C	$36	150	$2.59	100	110	40
[4]	D	$42	200			160	-
[5]	E	$60	200	$5.05	100	-	100
[6]	F	$72	50	$5.57	50	-	50
[7]	G	$78	50	$9.07	50	-	-
[8]	H	$210	150			-	-
[9]	**Totals**		**1250**		**300**	**720**	**190**
						Day-Ahead Outcomes	
		Demand Assumptions (MWh)				**Clearing Prices ($/MWh)**	
		Energy Demand		GCR Demand		LMP	GCR
[10]	**Totals**		**720**		**190**	**$42.00**	**$8.59**

As before, demand is assumed be a fixed 720 MWh and there is an ancillary service demand quantity for generation contingency reserves of 190 MWh, both of which are shown in row [10] of Table 7-9. This is the only reserve product; that is, we do not model energy imbalance reserve or the forecast energy requirement here.

► **Market outcomes.** The market-clearing outcomes are summarized in the last two columns of Table 7-9. Generators A through D again clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators C, E, and F (but not D) clear generation contingency reserve for a total of 190 MWh, equal to the ancillary service demand. The marginal offers for energy and for generation contingency reserve are those of Generator D and Generator C, respectively; for reference, these marginal offers and associated awards are shaded in light orange in Table 7-9.

In this example, the cleared awards do not fully illustrate *stack separation.* Generator C has a lower energy supply offer price than the marginal energy Generator D, yet Generator C clears (some) generation contingency reserve as well. This occurs because the next higher energy call option price that is uncleared, from Generator G, is very expensive. Thus, the market clearing output pushes some energy award onto higher energy-cost Generator D, in order to procure generation contingency reserve from Generator C instead of expensive Generator G.

Figure 7-5 shows the supply and demand diagram for the assumptions and results in Table 7-9. The energy supply offers of Generators B, C, and D are the same here as in prior Figure 7-4. The energy call option offer curve is different than in the prior Figure 7-4, however, because Generator D is assumed to not offer one.

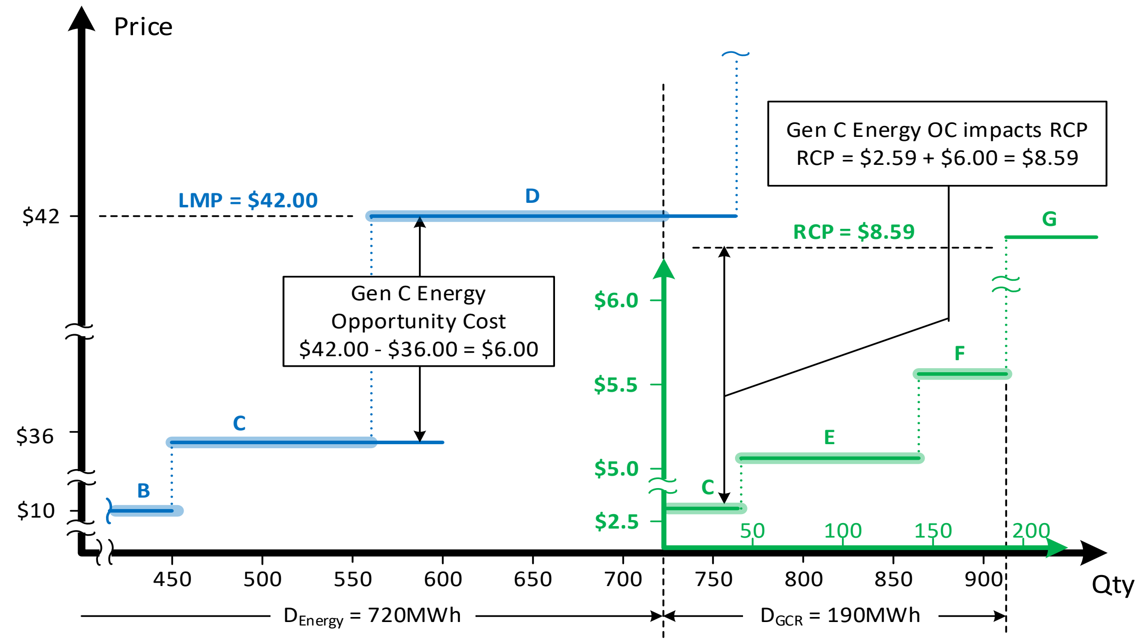

Figure 7-5. Market Clearing Outcomes for Example 4-B

► **Clearing prices.** Here, the day-ahead LMP is straightforward from Figure 7-5. Generator D is the highest-priced cleared energy supply offer, and does not sell all of its capability. It could therefore be used to serve the next increment of energy demand, at an incremental cost to the system set by Generator D's energy offer price of $42/MWh. The day-ahead LMP is therefore $42/MWh.

Does this price clear the market? At this price, all generators that clear for energy are willing to accept the price of $42/MWh or less; no generators that do not sell energy would be willing to do so at this price. *But,* there is one more thing to check: Generator C. Would it be willing to sell more energy at $42/MWh, given the profit it earns on its generation contingency reserve? To answer this question, we need to establish the clearing price for reserve. Two different methods arrive at exactly the same conclusion.

The marginal cost ('redispatch') method. Consider the marginal cost of procuring another unit of generation contingency reserve. Table 7-10 summarizes these calculations. Row [1] shows the additional MWh of generation contingency reserve from the marginal-for-reserve Generator C costs $2.59/MWh, its energy option offer price. That reduces the system's purchase of energy from Generator C, a savings of $36/MWh, its energy supply offer price. *See* row [4]. To continue to satisfy the energy demand of 720 MWh, however, the system must now procure another MWh of energy from marginal-for-energy Generator D. As shown in row [5], that cost is $42/MWh, its energy supply offer price. Putting all the pieces together, the marginal cost to procure another unit of generation contingency reserve $8.59/MWh, as shown in row [6]. Therefore, the reserve clearing price (RCP) is $8.59/MWh.

Now, back to the question earlier: does the $42/MWh LMP, *and* the $8.59/MWh RCP, clear this market? Now we can say yes. At this price, as before, all generators that clear for energy are willing to accept the price of $42/MWh or less; no generators that do not sell energy would be willing to do so at this price. And Generator C earns $6/MWh on the generation contingency reserve it sells: an $8.59/MWh RCP less Generator C's $2.59 energy call option offer price yields $6/MWh. That is no better than the $6/MWh it earns selling energy: A $42/MWh LMP less Generator C's $36/MWh energy supply offer price yields $6/MWh. The market clears.

Table 7-10. GCR Clearing Price Calculation for Example 4-B

	Change in Total (Production) Costs for One More MWh of GCR Demand		
[1]	+ 1 MWh of GCR from Generator C	$2.59	*Option offer price of GCR-marginal Gen C*
[2]			*(results in one less MWh of energy from Gen C)*
[3]	"Re-dispatch" Energy		
[4]	- 1 MWh of energy from Generator C	($36.00)	*"Savings" from one less MWh of energy from Gen C*
[5]	+ 1 MWh of energy from Generator D	$42.00	*Replacment cost of 1 MWh energy from marginal Gen D*
[6]		**$8.59**	*Marginal cost of GCR (GCR Clearing Price)*

The opportunity cost method. The economic perspective on the reserve clearing price is again in terms of opportunity cost. To see this, note again that Generator C's profit selling energy is the $42/MWh LMP less its energy supply offer price of $36/MWh, or $6/MWh. This is its opportunity cost of being cleared for reserve (per MWh of reserve), instead of being cleared for (additional) energy.

In order to make Generator C indifferent as to whether it supplies energy or reserve, this energy opportunity cost is incorporated *into* the reserve clearing price. Thus, the RCP is the sum of marginal generation contingency reserve seller Generator C's energy call option offer price of $2.59/MWh and its energy opportunity cost of $6/MWh: $2.59/MWh + $6/MWh = $8.59/MWh.

As before, this opportunity cost perspective aligns perfectly with the method of calculating clearing prices based on the system's marginal costs to procure incremental reserve.

► **Main points.** There are five points to note from this Example 4-B. First, the day-ahead LMP reflects the marginal cost of serving energy demand, and the RCP reflects the marginal cost of generation contingency reserve, consistent with sound economic principles. The marginal cost of generation contingency reserve includes the *inter-product opportunity cost* of not supplying additional energy that is incurred here by the marginal unit for reserve.

Second, this situation is analogous to the real-time co-optimized energy and reserve market. In that market, the real-time reserve clearing price is set by the marginal reserve resource's opportunity cost of not selling additional energy.

Third, consider why the opportunity cost is incorporated in the reserve clearing price in this Example 4-A, whereas it was incorporated in the energy clearing price (that is, the LMP) in prior example 4-A. First, a bit of terminology: we say that a resource is *capacity limited* if the sum of all of its awards (that is, energy MWh cleared and total energy option offer MWh cleared) is equal to the resource's total capacity. In Example 4-A, the marginal unit for *energy* is capacity limited; in that case, its opportunity cost is incorporated into the *energy* price. In this Example 4-B, the marginal unit for *reserves* is capacity limited; in this case, its opportunity cost is incorporated into the *reserve* price. This is true generally. And both situations are possible in practice, depending upon the precise combination of energy and option offers hour to hour.

Fourth, observe that in both Examples 4-A and 4-B, the clearing prices reflect the offers of the marginal units, but are not necessarily *equal to* the offers of the marginal units. That is because a co-optimized market will endogenously determine the correct intertemporal opportunity costs, and incorporate those into the market clearing prices.

Fifth, this example also illustrates that energy option offer prices *may* impact energy prices (as in Example 4-A), but do not necessarily impact energy prices (as in this Example 4-B). Put differently, reserve clearing prices do not 'cascade' into the energy price. This is in contrast to pricing for the various generation contingency reserve and replacement energy reserve products, the prices of which do cascade. We show this in our next two examples.

7.6 Example 5: Energy and Multiple Ancillary Service Co-Optimization

In this section, we now consider a pair of examples with co-optimization of energy and multiple generation contingency reserve and replacement energy reserve products. These examples will illustrate the price cascading logic of generation contingency reserve and replacement energy reserve, and how it sends the economically-correct price signals to the market.

In the next example 5-A in Section 7.6.1, we extend the assumptions in prior Example 4 to consider two generation contingency reserve products: 10-minute reserve, and 30-minute reserve. We will explain the price cascading logic using this two-reserve product example. Then, in Example 5-B in Section 7.6.2, we consider a situation with four products that includes both generation contingency reserve and replacement energy reserve, and examine the co-optimized market's price cascading logic in greater detail.

7.6.1 Example 5-A: Price Cascading with Two Generation Contingency Reserve Products and Co-optimized Energy

In Example 4-B, we showed that the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to reserve suppliers. In this example, that will continue to be the case. Our central point in this example is to show that the price cascading logic (and all the mathematics that goes with it) is, in effect, a method to ensure that the market properly incorporates seller's opportunity costs into the (correct) reserve prices.

This fact often lies just past intuition when contemplating a market with multiple ancillary services, as under the co-optimized day-ahead market upon implementation of these Energy Security Improvements. Thus, in this Example 5-A and the next Example 5-B, we show this that incorporating opportunity costs into reserve clearing prices is equivalent to the price cascading structure calculation discussed above, in Section 7.2.3.

► **Assumptions.** In this example, we make only one change from prior Example 4-B. We now assume that higher-cost Generator G submits a lower energy option offer price than in Example 4-B. That will enable it to receive a (partial) award, and better illustrate price cascading outcomes.

With multiple generation contingency reserve products, we now need to consider resources' ramp rates explicitly. Consistent with the co-optimized day-ahead market design and new market rules, we assume that:

- Each generator voluntarily chooses its energy call option offer price, and its energy call option offer MWh.
- The market-clearing software will calculate each generators' ramping capability (within 10-minutes, and within 30-minutes), based on the generators' submitted operating characteristics (*e.g.*, their submitted ramp rates, in MW per minute).
- Market awards for any generation contingency reserve or replacement energy reserve product will be limited by the lesser of: (a) the generator's offered energy call option offer MWh, and (b) the generator's total ramping capability corresponding to each product.

For example, if a generator offers 20 MWh of energy call option offers but can only ramp up at a rate of 1 MW per minute, its maximum possible award for GCR 10-minute reserve would be 10 MWh (10 minutes × 1 MW/minute × 1 hour award duration = 10 MWh).

Alternatively, if that generator only offered 5 MWh of energy call option offers, and had the same ramp rate, its maximum possible award for GCR 10-minute reserves would be only its 5 MWh offer. That is, no resource will receive a reserve award for a quantity that is did not offer to sell.

The same logic applies for all generation contingency reserve and replacement energy reserve product awards.

For convenience, the revised energy supply offer prices and quantities (*i.e.,* resource capacities), and the energy option offer price and quantities, for all eight Generators A through H are reproduced in Table 7-11 below, with the change to Generator G's energy call option offer price (now a lower value than assumed value in Example 4-B previously).

Last, in addition to the energy demand of 720 MWh as in the prior examples, we will assume a total-10 minute reserve demand quantity of 250 MWh, and a total 30-minute reserve demand quantity of 320 MWh. *See* row [10] in Figure 7-11. Note that, as discussed in Sections 7.2.2 and 7.2.3, these reserve demand quantities are *cumulative,* so awards of both GCR 10-minute reserve and GCR 30-minute reserve contribute to the total 30-minute reserve demand quantity.

Table 7-11. Assumptions and Market Outcomes for Example 5-A

		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		10-min	30-min	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	GCR10	GCR30
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	100	150	100	50	-
[4]	D	$42	200					170	-	-
[5]	E	$60	200	$5.05	200	100	200	-	100	70
[6]	F	$72	50	$5.57	50	50	50	-	50	-
[7]	G	$78	50	$5.81	50	50	50	-	50	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**450**	**300**	**450**	**720**	**250**	**70**
								Day-Ahead Outcomes		
		Demand Assumptions (MWh)						**Clearing Prices ($/MWh)**		
		Energy Demand		Total 10-min Demand		Total 30-min Demand		LMP	GCR10	GCR30
[10]	**Totals**	**720**		**250**		**320**		**$42.00**	**$8.59**	**$5.05**

In Table 7-11, the columns labeled Reserve Capability reflect the ramp rates for each generator that submitted an energy call option offer.[155] These are limiting only for Generators C and E: both can ramp up to their full energy option offer MWh in 30 minutes, but not in 10 minutes.

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-11. Generators A through D again clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators C, E, F, and G (but not D) clear GCR 10-minute reserve in a total amount of 250 MWh, equal to the total 10-minute reserve demand. Generator E clears GCR 30-minute reserve of 70 MWh. The sum of all GCR 10-minute reserve and GCR 30-minute reserve cleared therefore satisfies the total 30-minute demand quantity (250 MWh clearing as GCR 10-minute reserve and 70 MWh clearing as GCR 30-minte reserve adding to just satisfy the 320 MWh total 30-minute reserve demand quantity).

As is our convention, the marginal offers for energy and for each reserve product are shaded in light orange in Table 7-11. Generator D is again the marginal offer for energy; higher-priced Generator E is the marginal offer for GCR 30-minute reserve; but *lower*-priced Generator C is the marginal offer cleared for GCR 10-minute reserve.

[155] In practice, the ISO's market clearing system uses both on-line ramping rates and off-line startup times in determining these reserve capabilities, and accounts for both in making both commitment and reserve capability evaluations. We will not consider that level of detail here, in order to focus on the economic aspects of market prices.

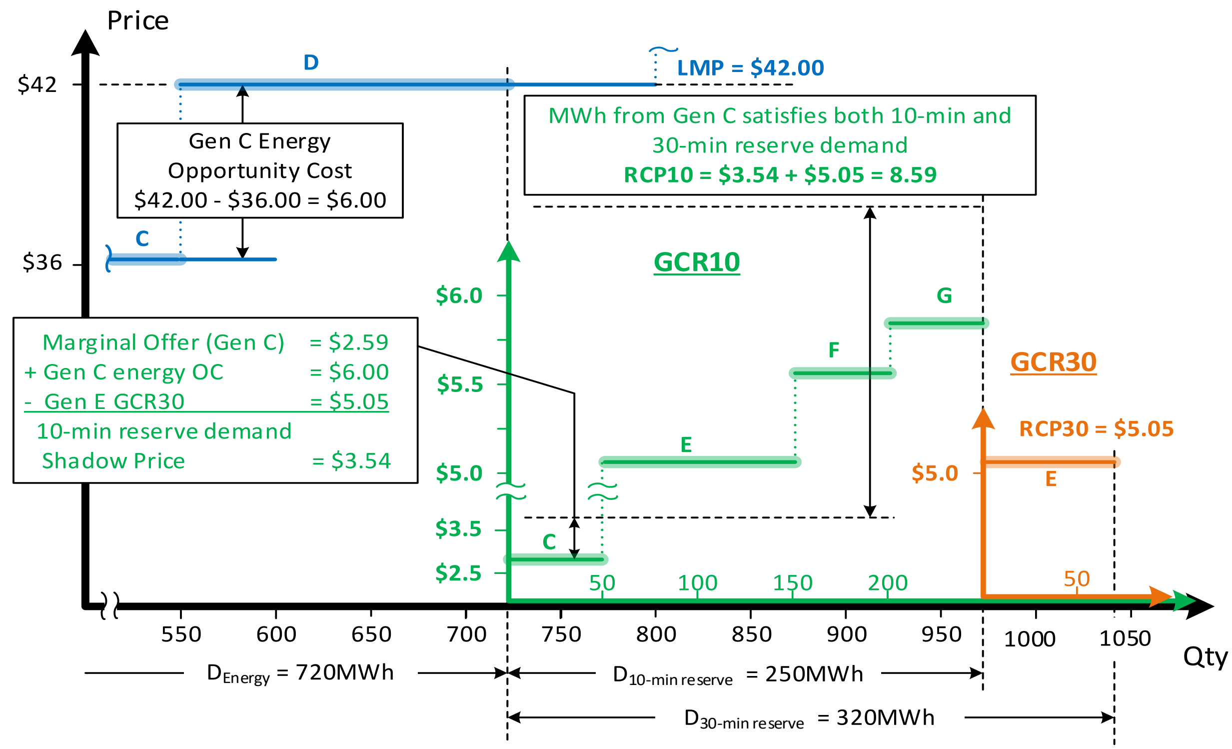

Figure 7-6. Market Clearing Outcomes for Example 5-A

That last observation suggests that Generator C may have an opportunity cost associated with its award. And indeed that is the case. To see how that plays out, Figure 7-6 shows the supply and demand diagram for the assumptions and results in Table 7-11.

Using the results in the last three columns of Table 7-11, Figure 7-6 shows the supply stack of energy supply offers and energy option offers that are cleared for each product. The energy supply stack, here showing the energy supply offers only for Generators C and D, is the same here as in prior Figure 7-4. The green stair-step supply curve in the middle represents the cleared GCR 10-minute reserve awards, in merit (*i.e.*, ascending offer price) order. The orange axes at the far right show the lone GCR 30-minute reserve award cleared, for Generator E.

► **Clearing prices and opportunity costs.** First, consider energy. The highest-priced cleared energy supply offer is from Generator D, and it has excess capacity to spare at its cleared energy quantity. So it would be used to satisfy an increment of energy demand, at a marginal cost to the system equal to its energy supply offer price of $42/MWh. Therefore, the day-ahead LMP is $42/MWh.

Now, at the opposite end of Figure 7-6, consider GCR 30-minute reserve. Generator E did not receive an award for all of its GCR 30-minute reserve; it has additional capability to spare. So it would be used to satisfy an increment of total 30-minute reserve demand, at a marginal cost to the system equal to is energy call option offer price of $5.05/MWh. Therefore, the market clearing price for GCR 30-minute reserve is $5.05/MWh.

Now, let's consider the price for GCR 10-minute reserve, in green in Figure 7-6. As noted in Table 7-11, lower-priced Generator C clears 100 MWh of energy, and 50 MWh of GCR 10-minute reserve. As a result, Generator C is capacity limited for energy and reserve. For energy, it is earning an LMP of $42/MWh and has an energy supply offer price of only $36/MWh, so it earns $42/MWh – $36/MWh = $6/MWh in profit on its energy. For each MWh of GCR 10-minute reserve it clears, then, it faces on opportunity cost of $6/MWh for not selling (additional) energy. Its marginal cost of supplying GCR 10-minute reserve is, as always in a multi-product market, the sum of its offer price and its opportunity cost of not selling something else. In this case, that comes to ($2.59/MWh energy option offer price + $6/MWh energy opportunity cost) = $8.59/MWh. Therefore, the market clearing price for GCR 10-minute reserve must be (at least) $8.59/MWh.

At these prices – the $42/MWh LMP, $8.59/MWh clearing price for GCR 10-minute reserve, and $5.05/MWh clearing price for GCR 30-minute reserve – each seller with an award of any product type is willing to accept that price or less, and no seller that is not awarded that product type would be willing to accept it a lower price. Therefore, the market clears.

► **Clearing prices: the price cascading method.** Now, this last step – checking that at all those prices, all of those sellers, with all of those offers, would find those prices to be their 'best deal' – is a doozy. It is work to check here, with eight generators and three products. It would be impractical to do so directly in a real co-optimized day-ahead market with a thousand resource offers and six ancillary service products.

Fortunately, there is a different way. The clearing prices can be calculated directly from the marginal cost logic, or the *shadow prices*, discussed previously in Section 7.2.3, and then 'cascaded' to set the clearing prices.

Table 7-12 steps through the calculations for the GCR 10-minute reserve clearing price. First, consider a 1 MWh increase in the 10-minute reserve demand quantity. That has a cost of $2.59/MWh, its energy call option offer price, as shown in row [2]. Procuring that from the marginal seller Generator C reduces its supply of energy by 1 MWh, because Generator C is capacity limited (the sum of its energy and GCR 10-minute reserve awards equals its total capacity). That would require another MWh of energy from the marginal energy supplier, Generator D, at a cost of $42/MWh; *see* row [6].

But, there is a another cost savings term to account for, because of the *product substitution* effect. Procuring another MWh of GCR 10-minute reserve contributes not only to the 10-minute reserve demand quantity, but also to the GCR 30-minute reserve demand quantity. That means the system can procure one less MWh of GCR 30-minute reserve, from Generator E. And that has a cost savings of $5.05/MWh, equal to Generator E's energy option offer price. *See* Row [9].

Table 7-12. GCR 10-Minute Reserve Clearing Price Calculation for Example 5-A			
[1]	**Change in Total (Production) Costs for One More MWh of 10-min Reserve Demand**		
[2]	+ 1 MWh of GCR10 from Generator C	$2.59	*Option offer price of GCR10-marginal Gen C*
[3]			*(results in one less MWh of energy from Gen C)*
[4]	"Re-dispatch" Energy		
[5]	- 1 MWh of energy from Generator C	($36.00)	*"Savings" from one less MWh of energy from Gen C*
[6]	+ 1 MWh of energy from Generator D	$42.00	*Replacment cost of 1 MWh energy from marginal Gen D*
[7]			
[8]	Substitution Effect of GCR10 for GCR30		
[9]	- 1 MWh of GCR30 from Generator E	($5.05)	*"Savings" from one less MWh of GCR30 from Gen E*
[10]		$3.54	*Shadow price of 10-min Reserve Demand*
[11]	Participation Payment Principle		
[12]	GCR10 contributes to 30-min Reserve Demand	$5.05	*Shadow price of 30-min Reserve Demand*
[13]		$8.59	*GCR 10-minute reserve clearing price*

Adding these all together yields the sum in row [10] of $3.54/MWh. That is the direct marginal cost of the *requirement*, that is, to satisfy another MWh increase in the 10-minute reserve demand quantity.

But that is not the market clearing price for the *product.* To get the correct product price, we have to apply the participation payment principle; *see* Section 7.2.3. Specifically, each MWh of GCR 10-minute reserve also contributes to the total 30-minute reserve demand quantity, which has a marginal cost of $5.05/MWh (set by Generator E's energy option offer price). Since each MWh of GCR 10-minute reserve contributes to both demand quantities, it must be paid the (shadow) price of each. The clearing price paid for the GCR 10-minute reserve *product* is therefore the sum of the two marginal costs: $3.54/MWh + $5.05/MWh = $8.59/MWh. *See* row [13].

► **Main points.** With multiple products that are one-way substitutes, as are generation contingency reserve and replacement energy reserve, there are two economically equivalent ways to interpret the market clearing prices. One is in terms of offer prices and opportunity costs. The other is the price cascading logic, which is how the clearing prices are calculated from incremental costs (or, more precisely, constraint shadow prices) in the actual market pricing software with thousands of offers.

The price cascading logic illustrated in Table 7-12 also reflects how the new Tariff provisions are written for the clearing prices for generation contingency reserve and replacement energy reserve in new Tariff Sections III.2.6.2(a)(ii)-(v). In particular, each price in Sections III.2.6.2(a)(ii)-(v) is determined by the marginal (that is, the incremental) cost of an incremental increase in the corresponding Day-Ahead Ancillary Service Demand Quantity, plus the clearing price of the specific Day-Ahead Ancillary Service Demand Quantity that is one step "lower" in the product substitution hierarchy. In this way, the pricing rules expressly and transparently incorporate the price cascading logic described above.

7.6.2 Example 5-B: Generation Contingency Reserve and Replacement Energy Reserve

The previous examples illustrated two key properties of the co-optimized day-ahead energy and ancillary services market. First, for generation contingency reserve and replacement energy reserve, calculating prices using the price cascading logic sets prices that properly compensate sellers for their inter-product opportunity costs. Second, incorporating those opportunity costs into the (correct) product prices clears the market: all awarded sellers are willing to accept that price or less, and all non-awarded sellers (of that product) would not be willing to accept that price.

The same price cascading and opportunity cost logic that applied to generation contingency reserve in the prior example also applies to replacement energy reserve, which shares the same product substitution and price cascading design. For completeness, we include here an example involving both generation contingency reserve and replacement energy reserve clearing and pricing.

In particular, this example will illustrate that generation contingency reserve and replacement energy reserve clearing prices cascade from slowest-ramping products to fastest-ramping products. The clearing prices resulting from this price cascading provides appropriate compensation, reflecting cleared option offer prices as well as opportunity costs.

► **Assumptions.** In this example, we have changed the offer prices for energy and energy options from the prior examples, to better illustrate multi-product price cascading. Table 7-13 summarizes the revised example assumptions. The last four columns reflect each generator's assumed ramping capability, from an on-line state and from an off-line state, within the time limits shown. As noted previously, these capabilities are based on generators' physical offer parameter data (*e.g.,* ramp rates, startup times, and such). The energy demand and total ancillary service demands are shown in row [9] of Table 7-13.

In this example, all generators that offer energy options offer their full capability as both energy and as energy call option offers. This is, in general, efficient; it lets the co-optimization logic find the most cost-effective (and profitable) assignment of awards to their resource's capabilities.

Nonetheless, we will assume that two generators choose not to offer energy call options (A and E). Two resources offer offline capability for clearing energy call options, higher-cost Generators F and G. In particular, Generator F can be online at its maximum output within 10 min; Generator G is slower, and can start up and reach 5 MW in 90 min and its maximum output within 4 hours.

► **Market outcomes.** The co-optimized market awards are shown in Table 7-14. Energy and reserve awards clear in the most efficient fashion, while respecting individual resource startup and ramping constraints. The reserve awards cascade to satisfy less restrictive requirements. For instance, the sum of all reserve awards shown in row [8] of Table 7-14 are equal to their respective total reserve demand quantities in row [8] of Table 7-13; or, stated more simply, the market clears sufficient reserve supply to (just) satisfy each reserve demand quantity in row [8] of Table 7-13.

Table 7-13. Assumptions for Example 5-B									
		Supply Offer Assumptions				**Reserve Capability (Online / *Offline*)**			
		Energy Supply Offers		**Energy Option Offers**		**10-min**	**30-min**	**90-min**	**240-min**
		Price	Quantity	Price	Quantity	Quantity	Quantity	Quantity	Quantity
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$10	450						
[2]	B	$36	150	$2.59	150	30 / -	90 / -	150 / -	150 / -
[3]	C	$42	200	$2.59	200	20 / -	60 / -	180 / -	200 / -
[4]	D	$60	160	$5.04	160	10 / -	30 / -	90 / -	160 / -
[5]	E	$72	40						
[6]	F	$78	100	$5.82	100	100 / *100*	100 / *100*	100 / *100*	100 / *100*
[7]	G	$210	20	$8.00	20	10 / -	20 / -	20 / *5*	20 / *20*
[8]	**Totals**		**1120**		**630**	**170 / *100***	**300 / *100***	**540 / *105***	**630 / *120***
						Reserve Demand (MWh)			
		Energy Demand (MWh)				**10-min**	**30-min**	**90-min**	**240-min**
[9]		**820**				**150**	**240**	**260**	**270**

Table 7-14 - Award Quantities for Example 5-B						
		Award Quantities				
		Energy	GCR10	GCR30	RER90	RER240
	Generator	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	450				
[2]	B	100	30	20		
[3]	C	140	20	40		
[4]	D	115	0	30	15	
[5]	E	15				
[6]	F		100			
[7]	G				5	10
[8]	**Totals**	**820**	**150**	**240**	**260**	**270**

Table 7-15. Pricing Outcomes for Example 5-B				
	Demand	**Shadow Price**	**Reserve**	**Clearing Price**
	Quantity	($/MWh)	**Product**	($/MWh)
[1]	**Energy**	$72	Energy	$72
[2]	Total 10	$0	GCR10	$38.59
[3]	Total 30	$21.55	GCR30	$38.59
[4]	Total 90	$9.04	RER90	$17.04
[5]	Total 240	$8	RER240	$8

► **Price cascading and clearing prices.** Table 7-15 shows the pricing outcomes. The shadow prices reflect the cost, at the margin, that would be incurred to meet an additional MWh of each demand quantity. The reserve product clearing prices, in the far-right column of Table 7-15, reflect the cascading of shadow prices. This satisfies the participation payment principle, and closely aligns with the structure of the clearing price definitions for generation contingency reserve and replacement energy reserve in new Tariff Sections III.2.6.2(a)(ii)-(v).

In Table 7-15, note that the reserve product clearing prices exceed (most) option offer prices, because the clearing prices incorporate the marginal resources' opportunity costs. As an example, consider the compensation of offline Generator G, which clears 5 MWh of RER 90-minute reserve and 10 MWh of RER 240-minute reserve. Its RER 90-minute reserve award helps to satisfy both the total 90- and total 240-minute demand quantities. From the participation payment principle, this award must be paid the shadow prices of *both* demands (constraints). Hence, the RER 90-minute reserve clearing price is $17.04/MWh (the sum of the shadow prices in row [4] and row [5] of Table 7-15 is $8/MWh + $9.04/MWh = $17.04/MWh). Generator G's total RER 90 award compensation is therefore 5 MWh x $17.04/MWh = $85.20.

Generator G's RER 240-minute reserve award helps to satisfy only the total 240-minute demand quantity. This award must be paid only the total 240-minute demand quantity shadow price. Hence, the RER 240-minute reserve clearing price is $8/MWh. Its RER 240-minute reserve award compensation is 10 MWh x $8/MWh = $80.

Finally, observe that the clearing price for GCR 10-minute reserve in row [2] of Table 7-15 and the clearing price for GCR 30-minute reserve in row [3] are the same, at $38.59/MWh. If the total 10-minute reserve demand quantity increased by one MWh, then marginal Resource D would clear 1 MWh of GCR 10-minute reserve (at a cost equal to its offer price, of $5.04/MWh), and one less MWh of GCR 30-minute reserve (at a savings equal to its offer price, of $5.04/MWh). That is, the "redispatch" occurs within the same resource. No incremental cost is incurred, so the shadow price is $0/MWh. This is why GCR 10-minute reserve and GCR 30-minute reserve have the same clearing price.

► **Prices reflect opportunity costs.** Consider the GCR 30-minute reserve clearing price of $38.59/MWh shown in row [3] of Table 7-15. Resource B is marginal for satisfying the total 30-minute demand quantity. This clearing price reflects both its energy call option offer of $2.59/MWh, and its energy opportunity cost of $36/MWh ($72/MWh LMP – $36/MWh energy offer = $36/MWh opportunity cost of not selling additional energy). The GCR 30-minute reserve clearing price is therefore $36/MWh + $2.59/MWh = $38.59/MWh.

Now consider the RER 90-minute reserve clearing price of $17.04/MWh shown in row [4] of Table 7-15. Resource D is marginal for satisfying the total 90-minute demand quantity. The clearing price reflects both its energy call option offer of $5.04/MWh, and its energy opportunity cost of $12/MWh ($72 LMP/MWh – $60/MWh energy offer = $12/MWh). The RER 90-minute reserve clearing price is therefore $12/MWh + $5.04/MWh = $17.04/MWh.

► **Summary.** This extended example further illustrates that how generation contingency reserve and replacement energy reserve clearing prices cascade up, so that sellers of faster-ramping products (higher in the product substitution hierarchy) always receive a price equal to or greater than sellers of slower-ramping products (lower in the product substitution hierarchy). The clearing prices reflect cleared option offer prices as well as opportunity costs, the participation payment principle, and basic foundation of marginal cost-based pricing.

7.7 Example 6: Energy Imbalance Reserve and Generation Contingency Reserve

We now return to the energy imbalance reserve and forecast energy requirement previously discussed in Section 6, and consider a pair of examples with both energy imbalance reserve and generation contingency reserve.

As motivation, consider again the results from Example 4-A. There, we found that with the single generation contingency reserve product, the day-ahead LMP was $44.95/MWh – higher than the marginal energy generator's offer price of $42/MWh. That $2.95/MWh difference appropriately reflected the generator's opportunity cost.

But consider that from a broader economic perspective. There is no generation contingency reserve in the real-time market – at least, not as an energy call option. If fact, there are no real-time reserve offer prices at all. Thus, the intertemporal opportunity cost for this marginal generator that was incorporated into the day-ahead LMP would, in all likelihood, not exist in the real-time market

In particular, suppose there is a zero real-time reserve price. Then, in the context of the results in earlier Example 4-A, market participants on the buy side of the market would see a higher price day-ahead – at the day-ahead LMP of $44.95/MWh – and a lower price in real-time, where there is no opportunity cost due to energy call options. Let's say that no system conditions change from day-ahead to real-time, so the real-time LMP is set by that same generator's offer price – which was $42/MWh.

That price spread would seem to have an undesirable effect: it would create an incentive for the demand side of the market to *not* buy energy day-ahead at $44.95/MWh, but instead to 'wait' and buy energy in real-time when it is cheaper, at $42/MWh. And it would be incented to continue to do so, until it bought sufficiently little day-ahead to 'back down' the day-ahead supply curve to where it equals the expected real-time price of $42/MWh. And that, in turn, would tend to create a problematic incentive for a *larger* energy gap between the day-ahead market outcome and the forecast energy requirement.

Of course, that seeming implication of Example 4-A isn't the full story. It isn't the full story because generation contingency reserve and replacement energy reserve are not being implemented in isolation. They and the forecast energy requirement within the co-optimized day-ahead market are a tightly coupled package, and have important interactions. In particular, the forecast energy requirement, its pricing, and the energy imbalance reserve effectively counter the potential incentive for demand to shift out of the day-ahead market, when suppliers' inter-product opportunity costs are now directly priced into the day-ahead energy price.

This plays out, in contrast to earlier Example 4-A, because the opportunity cost that went "into" the day-ahead energy price in that example will, in market equilibrium, instead tend to be incorporated into the Forecast Energy Requirement Price. And by so doing, the best that demand can do is *not* to avoid procuring energy day-ahead, but to procure as close to the forecast energy requirement as possible. In sum, arbitrage (by the demand side of the market) that seeks to avoid paying suppliers' energy opportunity costs (due to the generation contingency reserve and replacement energy reserve services) by withholding demand from the day-ahead market does not, in the end avoid paying suppliers' energy opportunity costs under these Energy Security Improvements.

We explore this important mechanism with the next pair of examples. To facilitate the analysis, we will use the same supply-side assumptions as in Example 4-A, with a single generation contingency reserve product. However, we will now enrich the demand side of the model, introducing demand side bidding, energy imbalance reserve, and the forecast energy requirement.

7.7.1 Example 6-A: The Forecast Energy Requirement Covers Energy Opportunity Costs

In this example, we revisit the same eight generators, Generator A through H, examined previously in Example 4-A in Section 7.5.1. Now, let's see what happens under the same supply conditions, with the forecast energy requirement and energy imbalance reserve added to the example.

Before proceeding, recall the key results from earlier example 4-A (*see* Section 7.5.1):

- Generator D's energy supply offer at $42/MWh was the marginal offer for energy.
- Generator D also sold generation contingency reserve, at a profit of $2.95/MWh.
- It therefore incurred an energy opportunity cost of $2.95/MWh.
- Proper marginal cost pricing, in that example, incorporated that $2.95/MWh opportunity cost for the marginal energy seller into the day-ahead energy price.

We also used the same supply assumptions about the generators in earlier Example 3-B in Section 6.3.2 as well, but came to different results (due to different demand assumptions, primarily). Let's also recall the key results from earlier example 3-B, which used the same supply assumptions but in which demand cleared less than the forecast energy requirement. In that example:

- Generator D's energy supply offer at $42/MWh was the marginal offer for energy.
- Energy demand cleared at 700 MWh, which was 20 MWh less than the forecast energy requirement.
- This led to a day-ahead LMP of $39.41/MWh, as the energy market cleared less demand.

- The difference between marginal Generator D's energy supply offer of $42/MWh and the day-ahead LMP of $39.41/MWh, which equals $2.59/MWh, was the Forecst Energy Requirement Price.

- With the Forecast Energy Requirement Price, Generator D's total day-ahead energy payment was $39.41/MWh + $2.59/MWh = $42/MWh.

Now, consider what happens if we combine these two prior examples. Does Generator D still earn only $42/MWh, its energy supply offer price? Or does the market still properly recompense the opportunity cost associated with introducing generation contingency reserve into the market design? We answer these questions next.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, examined previously in Example 4-A in Section 7.5.1. We assume there is one generation contingency reserve product, and a demand quantity for generation contingency reserves of 190 MWh. This is the only generation contingency reserve or replacement energy reserve product in the example; we could add more, but that would complicate the insights without altering the conclusions. As in Example 4-A (and Example 3-B), the forecast energy demand is assumed be a 720 MWh.

In this new example, we have changed two things from the prior Example 4-A. First, energy demand is no longer fixed. Instead, we assume there are three priced demand bids for energy. And second, we will introduce the forecast energy requirement and energy imbalance reserve.

For convenience, the energy supply offer prices and quantities (*i.e.,* resource capacities), and their energy option offer prices and quantities, are reproduced in Table 7-16 below. The columns that show Reserve Capability are different from one another; for energy imbalance reserve, this is equal to a generator's energy call option offer quantity. For generation contingency reserve, this may be limited to a lower value (as is the case for Generators C and D), based on the resource's ramp capability (as would be calculated by the ISO).

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-16. Generators A through D again clear energy supply offers, but only for a total of 700 MW – less than the forecast energy requirement of 720 MWh. Generators D and E clear generation contingency reserve for a total of 190 MWh, equal to that ancillary service's demand. Generator F clears 20 MWh of energy imbalance reserve, closing the gap to the forecast energy requirement.

On the demand side, bids 1 and 2 clear in full, totaling 700 MWh of day-ahead energy purchases. *See* row [13] of Table 7-16.

Table 7-16. Assumptions and Market Outcomes for Example 6-A

		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		EIR	GCR	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	EIR	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	150	100	150	-	-
[4]	D	$42	200	$2.59	200	200	100	100	-	100
[5]	E	$60	200	$5.05	90	90	90	-	-	90
[6]	F	$72	50	$5.54	50	50	50	-	20	-
[7]	G	$78	50	$5.82	50	50	50	-	-	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**540**	**540**	**390**	**700**	**20**	**190**
		Demand Assumptions								
		Energy Demand		Forecast Energy		GCR Demand				
		Price	Quantity	Quantity		Quantity				
		($/MWh)	(MWh)	(MWh)		(MWh)				
[10]	Bid 1	$55	500					500		
[11]	Bid 2	$45	200					200		
[12]	Bid 3	$35	100					-		
[13]	**Totals**		**800**	**720**		**190**		**700**		
				Day-Ahead Outcomes						
				Clearing Prices ($/MWh)						
				FERP				LMP	EIR	GCR
[14]				**$5.54**				**$39.41**	**$5.54**	**$5.54**

The marginal offers are shaded in light orange in Table 7-16. The marginal offer for energy is Generator D, as in prior examples 3-B and 4-A. Generator F's energy option offer is marginal for both energy imbalance reserve and generation contingency reserve.

Figure 7-7 shows the supply and demand diagram for the assumptions and results in Table 7-16. The energy supply offers in blue are the same here as in prior Figure 7-4 in Section 7.5.1. The green stair step supply curve shows the energy option offers cleared for generation contingency reserve; as in prior graphic, this starts from the forecast energy requirement. In this figure, the supply of cleared energy option offers for energy imbalance reserve is "squeezed" between the blue supply curve for energy and the green supply curve for generation contingency reserve; to help visual acuity, we have "bubbled" this out to the right in Figure 7-7, in orange.

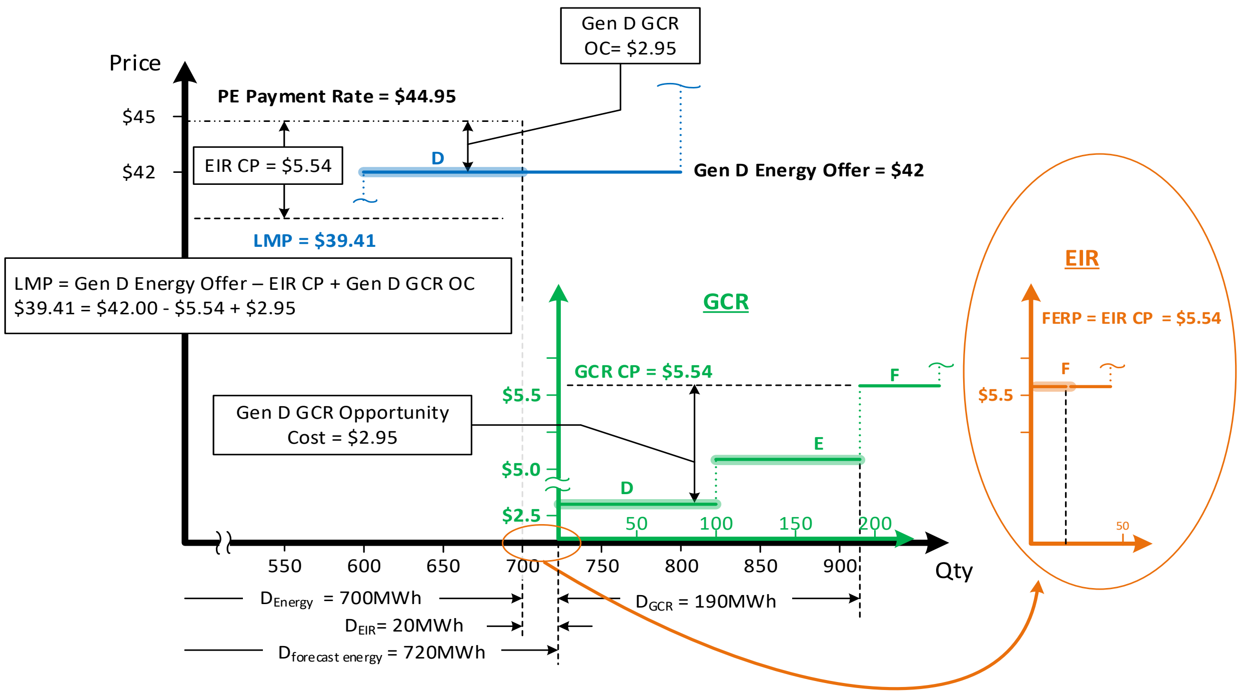

Figure 7-7. Market Clearing Outcomes for Example 6-A

► **Clearing prices.** Here, the clearing price for energy imbalance reserve and generation contingency reserve are straightforward from Figure 7-7. The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available.

What is the day-ahead LMP? Consider the marginal cost of another MWh of bid-in energy demand, which would increase cleared energy from 700 MWh to 701 MWh. Here there would be a re-dispatch that reduces the marginal cost of an additional increment of bid-in energy demand: each additional MWh of energy that clears from Generator D reduces the amount of energy imbalance reserve procured by a MWh as well. As explained in Section 6.2, the marginal cost of serving another MWh of bid-in energy demand is equal to marginal Generator D's energy supply offer of $42/MWh, minus its energy option offer of $2.59, or $42/MWh – $2.59/MWh = $39.41/MWh. Therefore, the day-ahead LMP is $39.41/MWh.[156]

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[156] The re-dispatch here has another step as well: when another MWh of energy demand clears and reduces the quantity of energy imbalance reserve needed by 1 MWh, it is cost-effective to 'switch' 1 MWh of Generator F's award from energy imbalance reserve to generation contingency reserve. That, by itself, costs nothing. Yet, it enables the system to reduce

► **The Main Point.** In this example, Generator D still sells generation contingency reserve profitably, and incurs a $2.59/MWh energy opportunity cost. Efficiency requires it to be paid a price that covers its supply offer price *and* that opportunity cost, which is $42/MWh + $2.59/MWh = $44.95/MWh. But if demand can procure less energy day-ahead than forecast and reduce the day-ahead LMP, how will Generator D get paid the sum of its energy supply offer price and energy opportunity cost?

The answer is: *the Forecast Energy Requirement Price.* Generator D, being a physical supply resource, is paid the sum of the day-ahead LMP and the Forecast Energy Requirement Price. This is $39.41 + $5.54/MWh = $44.95. In other words, the Forecast Energy Requirement Price covers the marginal energy supplier's opportunity cost when it profitably provides other ancillary services – generation contingency reserve and replacement energy reserve.

Let's compare again to the outcome in the earlier example 4-A. There, as here, Generator D was marginal for energy with a supply offer price of $42/MWh. It also incurred an energy opportunity cost of $2.95/MWh because it was inframarginal for generation contingency reserve. To cover its opportunity cost, the day-ahead LMP in Example 4-A was $44.95.

Now, consider the present example. Generator D again is a cost-effective (inframarginal) seller of generation contingency reserve, and incurs an energy opportunity cost of $2.95/MWh by doing so. It needs to be compensated for that opportunity cost, in addition to its energy supply offer price of $42/MWh.

But if the day-ahead LMP were $44.95/MWh, and the real-time LMP were (say) only $42/MWh, demand would have an incentive to not fully procure all 720MWh day ahead. Would that prevent generation from being properly compensated for their marginal cost, including opportunity cost?

With the forecast energy requirement, the answer is no. In this example, the generator's total energy payment – that is, the day-ahead LMP plus the Forecast Energy Requirement Price – is still $44.95/MWh – its marginal energy supply offer and its energy opportunity costs. With energy imbalance reserve, demand arbitrage does not eliminate suppliers' compensation for their intertemporal opportunity costs (that arises due to generation contingency reserve and replacement energy reserve). Rather, it shifts that opportunity cost compensation into the Forecast Energy Requirement Price.

This is illustrated in Figure 7-7. The Forecast Energy Requirement Price not only brings Generator D's total payment up from the day-ahead LMP to its energy supply offer price. It also brings the day-ahead LMP up to the *sum* of its energy supply offer price and its energy opportunity cost. And because it produces that outcome, it is sending the economically-correct price signal to supply, and compensating supply resources appropriately for their opportunity costs.

► **Summary and implications.** The point here is important. Generation contingency reserve and replacement energy reserve create new energy opportunity costs for physical energy resources in

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Generator D's award of generation contingency reserve by 1 MWh, which has a cost savings to the system of $2.59/MWh. The net marginal cost of serving another MWh of demand is therefore $42/MWh – $2.59/MWh = $39.41/MWh.

the day-ahead market. As discussed in previous examples, an efficient market must pay those opportunity costs, in addition to suppliers' offer prices. That, without any market demand reaction, would tend to raise day-ahead LMPs above real-time LMPs, inviting demand to shy away from participating in the day ahead market.

With the forecast energy requirement and energy imbalance reserve, that situation isn't just countered, it is reversed. In particular, the Forecast Energy Requirement Price will now internalize supplier's energy opportunity costs. As in Section 6.3, payments to physical supply resources at the sum of the day-ahead LMP and the Forecast Energy Requirement Price is the economically-appropriate compensation rate for their energy. That sum will cover both suppliers' marginal energy offer prices, as well as their opportunity costs, when they provide generation contingency reserve and replacement energy reserve.

Viewed more broadly, the forecast energy requirement and energy imbalance reserve, on the one hand, and generation contingency reserve and replacement energy reserve, on the other, are a tightly-coupled, highly interdependent design. Working together, they enable the markets to arbitrage the day-ahead to real-time LMPs – as should occur in a well-functioning market – without depriving supply resources of the economically appropriate compensation that must cover both their energy offer prices and their energy opportunity costs – which, together, will be higher than the LMP.

7.7.2 Example 6-B: Price Convergence.

In Example 6-A, the day-ahead LMP was $39.41/MWh. The real-time LMP, assuming the forecast energy demand is accurate (as we will presently), would be set where the generation energy supply curve intersects it. That price would be $42/MWh.

That price gap creates an incentive for demand (whether virtual or otherwise) to close the price gap, buying more day-ahead. That should not be unexpected with the forecast energy requirement, and it will tend to drive the cleared energy imbalance reserve MWh toward zero.

Two questions typically arise at this point: if the energy imbalance reserve is zero, will the Forecast Energy Requirement Price also be zero? What happens in equilibrium? In this section, we show how this plays out by extending the previous Example 6-A. Our main point is that in equilibrium, the day-ahead and real-time LMP will be equal (in expectation, that is); but the Forecast Energy Requirement Price will not (necessarily) be zero. Rather, it will be economically interpretable as paying physical suppliers their day-ahead energy opportunity costs when, at the day-ahead LMP, it is more profitable to sell energy call options and provide generation contingency reserve or replacement energy reserve.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, and the same assumptions as used in Example 6-A. We assume there is one generation contingency reserve product, and a demand quantity for generation contingency reserves of 190 MWh. The forecast energy demand is 720 MWh.

Table 7-17. Assumptions and Market Outcomes for Example 6-B

		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		EIR	GCR	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	EIR	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	150	100	150	-	-
[4]	D	$42	200	$2.59	200	200	100	120	-	80
[5]	E	$60	200	$5.05	90	90	90	-		90
[6]	F	$72	50	$5.54	50	50	50	-	-	20
[7]	G	$78	50	$5.82	50	50	50	-	-	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**540**	**540**	**390**	**720**	**0**	**190**
		Demand Assumptions								
		Energy Demand		**Forecast Energy**		**GCR Demand**				
		Price	Quantity	Quantity		Quantity				
		($/MWh)	(MWh)	(MWh)		(MWh)				
[10]	Bid 1	$55	500					500		
[11]	Bid 2	$45	200					200		
[12]	DEC	$42	50					20		
[13]	Bid 3	$35	100					-		
[14]	**Totals**		**850**	**720**		**190**		**720**		
				Day-Ahead Outcomes						
				Clearing Prices ($/MWh)						
				FERP				LMP	EIR	GCR
[15]				**$2.95**				**$42.00**	**$2.95**	**$5.54**

We change one assumption in this revised example. To profit from the day-ahead LMP at $39.41/MWh and (expected) real-time LMP at $42/MWh, we introduce a Decrement Bid (virtual demand bid) that buys day-ahead and sells-out in real time.

For convenience, the full assumptions for this Example 6-B are summarized in Table 7-17.

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-17. Demand now clears a 720 MWh, equal to the forecast energy demand (*see* row [14]). Generators A through D again clear energy supply offers, now for a total of 720 MWh. Generators D, E, and F clear generation contingency reserve for a total of 190 MWh, equal to that ancillary service's demand. Zero MWh of energy imbalance reserve is cleared.

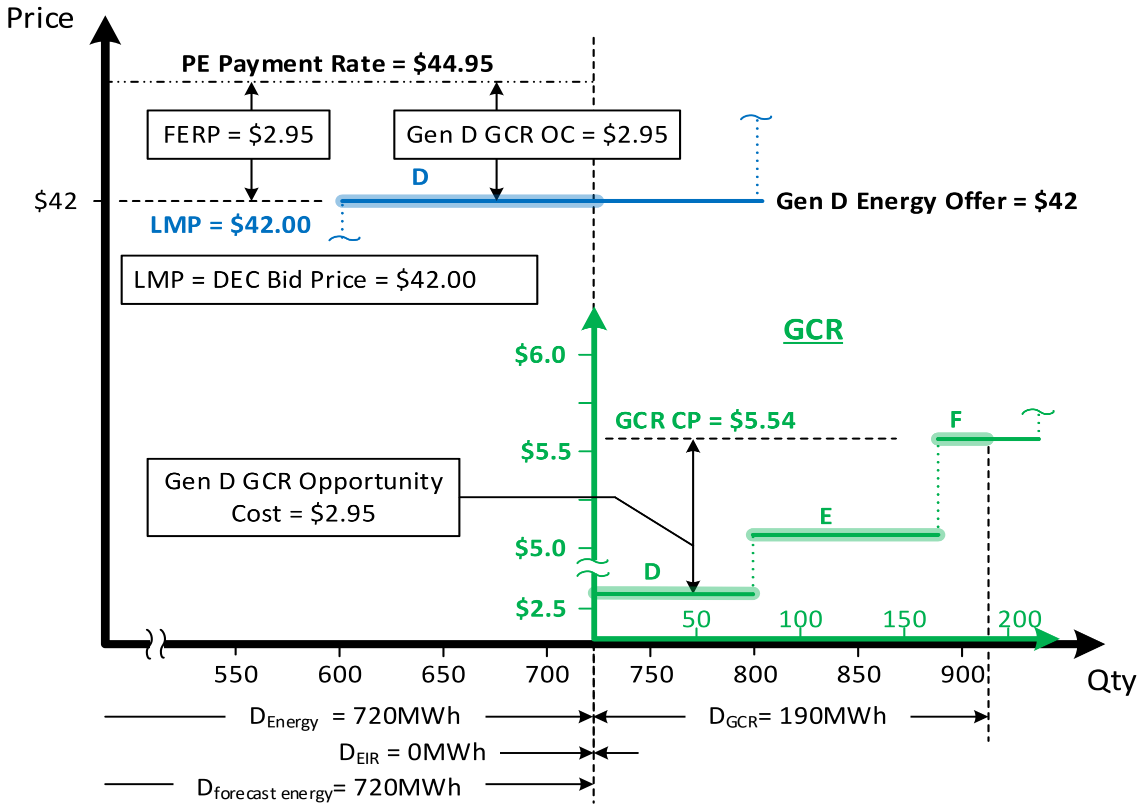

Figure 7-8. Market Clearing Outcomes for Example 6-B

On the demand side, bids 1 and 2 clear in full, totaling 700 MWh of day-ahead energy purchases. The Decrement Bid, priced at $42/MWh, partially clears 20 MWh. *See* row [12] of Table 7-17.

The marginal bids and offers are shaded in light orange in Table 7-17. The marginal offer for energy is Generator D, as in prior examples 3-B and 4-A. Generator F's energy option offer is marginal for generation contingency reserve.

Figure 7-8 shows the supply and demand diagram for the assumptions and results in Table 7-17. The energy supply offers in blue are the same here as in prior Figure 7-4 in Section 7.5.1. The green stair step supply curve shows the energy option offers cleared for generation contingency reserve; as in prior graphic, this starts from the forecast energy requirement.

► **Clearing prices.** Here, the clearing price for generation contingency reserve is straightforward from Figure 7-8 The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. As in Example 6-A, Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available.

Here the day-ahead LMP is set by demand – specifically, the Decrement Bid at $42/MWh. That is where the energy supply curve and energy demand curves intersect.

What is the Forecast Energy Requirement Price? Since cleared energy imbalance reserve is zero, we have to calculate the incremental cost of a change in the forecast energy requirement. Table 7-18 summarizes the steps. An additional MWh increase in the forecast energy requirement would be satisfied by another unit of energy supply from marginal Generator D. But Generator D must have a demand bid to clear against more energy – and does, in the form of the Decrement Bid at the same price. They match and clear with an increase in the forecast energy requirement.

However, when Generator D sells another MWh of energy, it has one less MWh of generation contingency reserve (as Generator D is capacity limited; *see* Table 7-17). That causes a re-dispatch of generation contingency reserve from Generator D to Generator F, which is the marginal energy option offer. The net cost, as shown in Table 7-18, is $2.95/MWh. Therefore, the Forecast Energy Requirement Price is $2.95/MWh.

Table 7-18. Forecast Energy Requirement Price Calculation for Example 6-B

[1]	**Change in Total (Production) Costs for One More MWh of Forecast Energy Demand**		
[2]	+ 1 MWh of energy from Generator D	$42.00	*Energy offer price of FER-marginal Gen D*
			(results in one less MWh of GCR from Gen D)
[3]	+1 MWh of energy from DEC	($42.00)	*Bid price of DEC*
[4]	"Re-dispatch" GCR		
[5]	- 1 MWh of GCR from Generator D	($2.59)	*"Savings" from one less MWh of GCR from Gen D*
[6]	+ 1 MWh of GCR from Generator F	$5.54	*Option offer price to replace the GCR MWh from Gen F*
[7]		$2.95	*Forecast Energy Requirement Price*

► **Implications**. There are three main points to note here. First, demand has a strong incentive, with a forecast energy requirement, to clear energy close to that amount. This will tend to drive cleared energy imbalance reserve toward zero.

Second, even when cleared energy imbalance reserve is zero, the Forecast Energy Requirement Price may not (and commonly may not) be zero. This is because it is covering the energy opportunity cost of the marginal physical supply resource. That energy opportunity cost arises because of the opportunity to provide generation contingency reserve and replacement energy reserve.

Third, this tightly-coupled design – an architectural balance between two economically self-reinforcing mechanisms – requires both energy imbalance reserve and the forecast energy requirement, as well as generation contingency reserve and replacement energy reserve. The former ensures that, in equilibrium, all physical energy supply resources have new compensation with which to undertake costly investments in advance of the operating day. The latter ensures that the resources that the system must rely upon to manage uncertainty during the operating day now have new compensation, and new incentives, to arrange energy supplies even on days when they may not expect to run. And, with the two put together, they jointly ensure that the market properly compensates resources not only for their direct costs of supplying energy, but also for their opportunity costs when they are scheduled to provide any of the new ancillary services instead.

8. Conclusion

The detailed explanations and numerous examples set forth across more than 200 pages in this paper underlie an ultimately simple point. The markets as constructed today contain a significant omission: when it would be to society's benefit (considering both cost and reliability) for a resource to procure fuel in advance, providing important energy security for the region, the resource is not incented to do so.

To date, this problem has not created irreversible risks. And there has been sufficient capability in the system, such that the ISO has consistently been able to rely on the capabilities of resources operating above and beyond their day-ahead schedules to provide the essential reliability services that cover the various energy gaps described herein. And without additional compensation, no less.

But circumstances are changing quickly. Retirements of legacy resources, the burgeoning of renewable resources, and continued gas pipeline constraints will leave the region reliant on 'just-in-time' resources in an unprecedented manner. And this evolving resource mix, with no emphasis on advance fuel arrangements, cannot be relied on in the same way to provide these essential reliability services. The markets must be expanded now to compensate for these services, to ensure they are available as needed.

The Energy Security Improvements detailed in this paper will accomplish this. In a fully market-based and transparent manner, these essential reliability services will be procured and compensated in the day-ahead market. Importantly, this should not be considered a new set of market products. Rather, the Energy Security Improvements create a proper market mechanism for essential services that are needed and procured today, but that are currently procured inefficiently and outside of the markets. With the Energy Security Improvements in place, resource owners will face clear market incentives to arrange fuel in advance of the operating day when it would be beneficial for society for the resource owner to do so.