March 25, 2019

BY ELECTRONIC FILING

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

Re: ***ISO New England Inc.*, Docket No. ER19-_____-000; Inventoried Energy Program**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. ("ISO") hereby submits to the Federal Energy Regulatory Commission ("Commission") this transmittal letter and revisions to the ISO's Transmission, Markets and Services Tariff ("Tariff") to implement an inventoried energy program for the winters of 2023-2024 and 2024-2025 (in the Capacity Commitment Periods associated with the 14th and 15th Forward Capacity Auctions).[2] This program will provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed. This filing fulfills a commitment that the ISO made in 2018 to identify an interim solution that could complement efforts currently underway to develop a long-term, market-based solution to the region's energy security challenges. As discussed in Part VII below, **the ISO respectfully requests an effective date of May 28, 2019 for these changes**.

In support of these Tariff changes, the ISO is submitting the testimony of Dr. Christopher Geissler, an Economist working in the ISO's Market Development Department ("Geissler Testimony"), and the testimony of Dr. Todd Schatzki, a Vice President at Analysis Group, a

[1] 16 U.S.C. § 824d (2018).

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff.

consultant retained by the ISO to assist in the development of core components of the inventoried energy program ("Schatzki Testimony").

I. DESCRIPTION OF THE ISO; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO plans and operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

Kerim P. May, Esq.
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4551
E-mail: kmay@iso-ne.com

II. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[3] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[4] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[5] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[6] The changes proposed herein

[3] *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

[4] *Id.* at 10 (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[5] *Id.* at 9.

[6] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) ("*Bethany*").

"need not be the only reasonable methodology, or even the most accurate."[7] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[8]

III. BACKGROUND

On May 1, 2018, the ISO filed with the Commission seeking waiver of certain Tariff provisions so that the ISO could retain, in order to maintain fuel security, two generating units that had indicated an intent to retire.[9] In a July 2, 2018 order,[10] the Commission rejected that waiver request, and (among other things) directed the ISO to: (1) file Tariff revisions by August 31, 2018 to provide for a short-term, cost-of-service agreement to address demonstrated fuel security concerns; and (2) file Tariff revisions later in 2019 that improve the market design in New England to better address fuel security concerns.[11] With respect to the first of these requirements, the Commission noted that "there appear to be material differences between retaining resources through cost-of-service agreements for local transmission needs and retaining resources through cost-of-service agreements for regional fuel security concerns,"[12] and suggested that it may be appropriate for resources retained for fuel security reasons to be retained outside of the Forward Capacity Market construct,[13] or offered into the Forward Capacity Auction at a price above zero.[14] In any case, the Commission indicated that the ISO's solution "should include a mechanism that addresses how resources retained for fuel security (e.g., under cost-of-service agreements) would be treated in the [Forward Capacity Market]."[15]

---

[7] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[8] *Cf. Southern California Edison Co., et al,* 73 FERC ¶ 61,219 at p. 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (citing *Bethany*)).

[9] *See* Petition of ISO New England Inc. for Waiver of Tariff Provisions, FERC Docket No. ER18-1509 (filed May 1, 2018).

[10] *See* Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines, 164 ¶ 61,003 (issued July 2, 2018) ("July 2, 2018 Order Denying Waiver Request").

[11] *See* July 2, 2018 Order Denying Waiver Request at P 55.

[12] July 2, 2018 Order Denying Waiver Request at P 57.

[13] *See* July 2, 2018 Order Denying Waiver Request at P 56.

[14] *See* July 2, 2018 Order Denying Waiver Request at P 57.

[15] July 2, 2018 Order Denying Waiver Request at P 57.

On August 31, 2018, the ISO made the first of those two required filings.[16] The Tariff revisions filed on August 31 included provisions allowing the ISO to retain resources for fuel security reasons; provisions for a short-term, cost-of-service agreement for resources retained for fuel security reasons; and provisions regarding how resources retained for fuel security reasons would be treated in the Forward Capacity Market. On this latter point – the treatment of such resources in the Forward Capacity Market – the ISO explained that, of the approaches that could be implemented in time for the 13th Forward Capacity Auction (conducted in February 2019), the two approaches suggested by the Commission in the July 2, 2018 order (retention of the resource outside the Forward Capacity Market or offering the resource into the market at a price above zero) potentially created less desirable economic outcomes than simply treating resources retained for fuel security reasons as price-takers in the Forward Capacity Auction.[17] The Commission accepted this approach in an order dated December 3, 2018.[18]

The ISO acknowledged, however, that the price-taker approach does not properly compensate resources that provide both resource adequacy and fuel security, and explained that a full market-based solution to that problem would be very challenging to design, and could not be implemented in time for the 13th Forward Capacity Auction.[19] Nonetheless, the ISO made a commitment in the August 31, 2018 Filing to work with stakeholders

> to identify an alternative that can be applied for FCA 14 and 15 in conjunction with its efforts to continue to develop longer-term market solutions to the region's fuel security challenges. Among the ideas the ISO plans to assess is an incremental payment for resources that can help the region meet its fuel security objectives.[20]

The interim inventoried energy program filed here represents the fulfillment of that commitment. As explained in detail below, the program will be in place in the winters of 2023-2024 and 2024-2025 (in the Capacity Commitment Periods associated with the 14th and 15th Forward Capacity Auctions), and will provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most likely to be stressed.

---

[16] *See* ISO New England Inc. Compliance Filing to Establish a Fuel Security Reliability Standard, Short-Term Cost-of-Service Mechanism, and Related Cost Allocation for Out-of-Market Compensation, FERC Docket Nos. EL18-182-000 and ER18-2364-000 (filed August 31, 2018) ("August 31, 2018 Filing").

[17] *See* August 31, 2018 Filing at 15-18.

[18] *See* Order Accepting Compliance Filing and Requiring Informational Filings, 165 FERC ¶ 61,202 at PP 82-88 (issued December 3, 2018).

[19] *See* August 31, 2018 Filing at 17.

[20] August 31, 2018 Filing at 18.

IV. EXPLANATION OF THE INVENTORIED ENERGY PROGRAM

A. Objectives of the Inventoried Energy Program

As Dr. Geissler explains in his testimony, the ISO identified a number of design objectives that it sought to satisfy when developing the interim program. The first objective is that the program had to be simple enough that: (i) it could be designed and filed by the ISO quickly; and (ii) Market Participants can reasonably forecast potential revenue from the program when making retirement decisions. As a threshold matter, an interim program would be ineffective if it could not be in place before the full, long-term solution. And if it is to reduce the likelihood that otherwise economic resources that improve energy security retire, the program must be understood by Market Participants before any retirement decisions are finalized. Furthermore, because the program is only scheduled to be in place for two winters, it is practical to prioritize simplicity when considering design options and their corresponding implementation requirements. Simplicity in both the design and implementation of this interim program will better allow the ISO to make progress on its longer-term, market-based approach to energy security.[21]

The second objective is to compensate resources that provide winter energy security, and thereby improve the region's reliability during stressed winter conditions relative to the status quo where no such program is in place. This objective can be satisfied through two different mechanisms. First, the compensation provided by the program may incent resources to take actions that they otherwise would not take that improve the region's winter energy security. Second, this objective can be satisfied if the compensation provided by the program deters resources that provide winter energy security during stressed winter conditions from pursuing retirement, thereby reducing the likelihood that such resources and their reliability attributes exit the market or are retained through out-of-market actions that may adversely impact the wholesale markets.[22]

The third objective is adherence to sound market design principles. The ISO seeks to satisfy sound market design principles in all cases where it is establishing a new product or modifying an existing product. These sound market design principles include: specifying a clearly defined product or attribute, transparently pricing the product or attribute, incenting Market Participants to deliver the product or attribute in a cost-effective manner, and settling any forward sale of the product or attribute against its spot delivery. A particularly important design

[21] Geissler Testimony at 6.

[22] Geissler Testimony at 6-7.

principle is that the framework should strive to be technology-neutral by providing similar compensation for similar service.[23]

Unfortunately, Dr. Geissler explains, these objectives are fundamentally in tension. The first objective – that the design be simple enough to be in place in time to potentially influence near-term retirement decisions – is paramount here. The ISO and stakeholders are already hard at work on a full, market-based solution to the region's energy security issues, but that solution will require more time to design and implement. There is little reason to pursue an interim solution that cannot provide compensation for resources providing winter energy security before that long-term solution is in place.[24]

The primary casualty of the interim program's adherence to simplicity is the third objective – following each of the sound market design principles. Fully incorporating those principles would add significant complexity to the program. For example, it would require a robust specification of demand for the desired reliability attribute. And it would require the development of a mechanism, such as the introduction of a new auction or significant changes to an existing auction, to buy this product from the set of suppliers that could sell it at lowest cost. Such features would require significant additional design work that would not have allowed the ISO to complete the design in time to potentially influence retirement decisions for the upcoming Forward Capacity Auction to be conducted in February 2020. Furthermore, such features would add complexity to the implementation process, which could jeopardize the ISO's ability to implement the interim program for the winter of 2023-2024.[25]

One market design principle not being compromised here, however, is ensuring that the program provides similar compensation for similar service. This property is a bedrock of market design, and is generally consistent with the ISO's endeavors to compensate Market Participants in a technology-neutral manner. The interim program strives to ensure that all providers of inventoried energy are similarly compensated.[26] In this regard, the inventoried energy program marks a significant departure from the previous winter reliability programs. Those previous programs focused on incenting incremental fuel procurement during the winter,[27] while the instant program seeks to ensure that all participants providing the inventoried energy product are consistently compensated for this reliability attribute. While the inventoried energy program

[23] Geissler Testimony at 7.

[24] Geissler Testimony at 7-8.

[25] Geissler Testimony at 8.

[26] Geissler Testimony at 8.

[27] *See, e.g.*, Order on Proposed Tariff Revisions, 152 FERC ¶ 61,190 at P 47 (issued September 11, 2015).

includes administrative features, it is much more consistent than the previous programs with the Commission's (and the ISO's) preference for market-based solutions.[28]

Finally, as to the objective of improving winter energy security during stressed conditions, the interim program being filed here is directionally correct. The program will create incentives for resources to take actions that increase their inventoried energy during periods of system stress, and these actions may improve the region's winter energy security. Additionally, the revenue that the program is likely to provide to resources that improve winter energy security through the maintenance of inventoried energy should decrease the likelihood that such resources pursue retirement, which may help to ameliorate the region's winter energy security concerns. The ISO cannot guarantee, however, that the program will incent specific resources to take precise actions that improve winter energy security or deter any particular resource that would otherwise be economic from retiring. To achieve such outcomes, the design would need to fully specify the value of the winter energy security attributes that are currently not being compensated. And again, to do so would require a program that fully specifies the region's demand for these attributes, which would add significant complexity and likely undermine meeting the paramount objective of simplicity and timeliness. The ISO believes that the interim program being filed here appropriately balances these competing objectives and serves as a bridge to the full, market-based solution.[29]

Dr. Geissler emphasizes the importance of having the interim program in place as soon as possible. If the interim program is to discourage potential retirements from otherwise economic resources that provide winter energy security – thereby helping to meet the second objective mentioned above – it must be in place before those retirement decisions are made. The Forward Capacity Market rules generally require that a resource notify the ISO of its intent to retire approximately four years before actually discontinuing operations. In fact, retirement de-list bids for the next Forward Capacity Auction, which will be conducted in February 2020, were due to the ISO on March 15, 2019, and any resulting retirements would likely occur on June 1, 2023 (the start of the Capacity Commitment Period that is associated with the February 2020 Forward Capacity Auction). Having this program vetted by stakeholders, with the understanding that the ISO will file it with the Commission in time for the February 2020 Forward Capacity Auction, has allowed resources to consider the program's potential incremental revenue during the 2023-2024 winter in making their decision as to whether, or at what price, to submit retirement de-list bids in the February 2020 Forward Capacity Auction.[30]

---

[28] *See, e.g.*, July 2, 2018 Order Denying Waiver Request at P 53.

[29] Geissler Testimony at 9.

[30] Geissler Testimony at 10.

B. The Inventoried Energy Product

In his testimony, Dr. Geissler explains why the program focuses on inventoried energy. A key contributor to the region's winter energy security concerns is its reliance on electric energy from gas-fired resources that rely on the gas delivery from the interstate pipeline network, which can become constrained during winter cold spells. The potential lack of inventoried energy available to be converted to electric energy during such winter cold spells where system conditions are stressed could potentially lead to loss of load events. This program seeks to reduce this concern by directly compensating resources for maintaining inventoried energy that can then be converted into electric energy during such cold spells. Consistent with the second objective described above, this financial incentive may help to address the region's winter energy security concerns in the short term by incenting resources in the region to maintain greater inventoried energy levels than would otherwise occur absent the program, and by reducing the likelihood that resources with inventoried energy pursue retirement before the implementation of the full, market-based solution.[31]

The program defines inventoried energy as fuel or potential energy that a resource can convert to electric energy at the ISO's direction. This definition generally allows resources that use a broad set of fuels to participate in the program. For example, if an oil resource has an on-site tank containing enough oil to operate the resource for two days, that resource has two days of inventoried energy.[32]

Dr. Geissler explains that the program may incent the region to maintain greater inventoried energy levels than would otherwise occur by compensating resources that maintain inventoried energy that can be converted to electric energy at the ISO's direction during cold winter conditions. There are several reasons that this may lead the region to maintain greater inventoried energy levels. First, the program may incent Market Participants to acquire more inventoried energy than they otherwise would absent the program. Direct compensation for inventoried energy may lead a resource to arrange for more inventoried energy at the start of the winter, as this incremental inventory may increase its expected inventoried energy revenues. Furthermore, as a resource depletes its inventory, the resource may consider replenishing its stock of inventoried energy to earn greater program revenues during cold winter conditions that occur later in the winter.[33]

---

[31] Geissler Testimony at 11.

[32] Geissler Testimony at 11.

[33] Geissler Testimony at 12.

Second, this interim program may change if and when this inventoried energy is converted to electric energy, allowing it to be available for stressed winter conditions that occur later in the season. Specifically, the program creates a potential opportunity cost associated with converting inventoried energy into electric energy, as this conversion reduces a resource's remaining inventoried energy, and this may therefore decrease its program revenues going forward. As a result, resources that generate electricity by converting inventoried energy to electric energy are likely to include an opportunity cost that increases their energy market offer price. This in turn will tend to reduce the likelihood that such resources are dispatched, and increase the likelihood that resources that do not use inventoried energy (or that have a significant stock of inventoried energy, and thus have little or no opportunity cost associated with using it now) are dispatched in their place. This effect on dispatch will help maintain the region's inventoried energy so that it is available later in the winter if system conditions are stressed.[34]

Third, because the program will provide incremental revenue to resources that maintain inventoried energy during stressed winter conditions (and hence reduce the amount of revenue those resources must recover through the capacity market), it may therefore decrease the likelihood that such resources seek to retire. The continued operation of such resources will contribute to the region's winter energy security.[35]

C. Main Components of the Inventoried Energy Program

The program consists of five core components that work together to provide compensation for resources that maintain inventoried energy during stressed winter conditions. These five components are: (1) the two-settlement structure; (2) the forward rate; (3) the spot rate; (4) the trigger conditions; and (5) the maximum duration.

1. The Two-Settlement Structure

The interim program employs a two-settlement structure to determine program settlements. Participation in the inventoried energy program is voluntary, and a Market Participant may elect to participate in both the forward and spot components of the program, or only in the spot component of the program. A Market Participant electing to participate in both the forward and spot components is paid the forward rate for each MWh of inventoried energy that is sold forward. The spot rate is then applied to deviations between the MWh of inventoried

[34] Geissler Testimony at 12-13.

[35] Geissler Testimony at 13.

energy maintained for each trigger condition (called an "Inventoried Energy Day") and the MWh of inventoried energy sold forward.[36]

As is standard in two-settlement structures, a participant electing to sell inventoried energy forward will get paid the forward rate for each MWh sold forward – this corresponds with the 'first settlement' in the two-settlement structure. In exchange for this payment, the participant takes on a financial obligation associated with this forward sale to maintain the MWh amount the participant elected forward for each Inventoried Energy Day during the December through February period of the program. This financial obligation is enforced through a 'second settlement' that settles any deviation from the quantity of inventoried energy sold forward at the spot price. Specifically, this second settlement is equal to the product of the Market Participant's deviation between its actual spot delivery of the product (which is also capped at 72 hours of its maximum potential output) and its forward obligation, and the spot price.[37]

Positive deviations, where the Market Participant's delivery of inventoried energy for an Inventoried Energy Day exceeds its forward position, correspond with a positive payment in the second settlement, reflecting that the participant provided more inventoried energy than was obligated in its forward sale. Negative deviations, where the Market Participant's delivery of inventoried energy for an Inventoried Energy Day falls short of its forward sale, correspond with a negative payment (or charge) in the second settlement. If the participant's delivery of inventoried energy for an Inventoried Energy Day is exactly equal to its forward sale, the second settlement is $0 because there is no deviation.[38] In his testimony, Dr. Geissler provides some examples illustrating how the two-settlement design works.[39]

2. The Forward Rate

The forward rate represents the payment that a Market Participant receives for each MWh of inventoried energy sold forward. In exchange for this compensation, the Market Participant takes on a financial obligation to maintain its elected amount of inventoried energy for each Inventoried Energy Day during the program delivery period (December through February).[40]

---

[36] Geissler Testimony at 13-14.

[37] Geissler Testimony at 19-20.

[38] Geissler Testimony at 20.

[39] *See* Geissler Testimony at 20-22.

[40] Geissler Testimony at 22.

The program specifies a fixed forward rate of $82.49 for the entire delivery period for each MWh sold forward.[41] This is an estimate of the minimum rate that would incent a gas-only resource to sign a winter peaking supply contract for vaporized liquefied natural gas ("LNG"). In his testimony, Dr. Geissler explains why it is appropriate to set this rate at the minimum rate that would incent a gas-only resource to sign a winter-peaking supply contract,[42] and that this rate is expected to also incent oil resources to maintain inventoried energy.[43]

To estimate this rate, the ISO contracted with Dr. Todd Schatzki of the Analysis Group. Dr. Schatzki has expertise in power system economics, the region's natural gas infrastructure, and economic modeling. To establish this forward rate, he developed a simulation model that used historical gas price data to estimate a fair market value gas contract between a gas-only generator and a storage terminal that holds liquefied natural gas. Dr. Schatzki then estimated a generator's expected incremental revenues and costs associated with signing such a gas contract, and determined the outstanding contract costs that must be recovered through the interim program so that the generator 'breaks even' from signing this contract. This 'break even' payment was then converted into the forward rate for the interim program. The methodology and assumptions used to establish this forward rate are described in significant detail in the memorandum that is included as an attachment to the Schatzki Testimony.[44]

3. The Spot Rate

The spot rate represents the payment rate that is applied to deviations between the inventoried energy maintained by a participant for each trigger condition, and that sold forward. For example, a resource that does not sell any inventoried energy forward will get paid the spot rate for each MWh of inventoried energy maintained each time the trigger conditions are met. This spot rate is set at $8.25 per MWh for each trigger condition in the delivery period, and it is derived from the forward rate.[45]

Dr. Geissler explains that the spot rate is calculated such that a resource would expect to earn similar total program revenues for selling the same quantity of inventoried energy via the forward or spot settlement. By ensuring that selling inventoried energy forward is not expected

---

[41] Geissler Testimony at 15.

[42] *See* Geissler Testimony at 22-24.

[43] *See* Geissler Testimony at 24-25.

[44] Geissler Testimony at 25; Schatzki Testimony at 2-6. *See also* Attachment B to Schatzki Testimony (memorandum titled "Calculation of Rate for Interim Compensation Program").

[45] Geissler Testimony at 15.

to produce greater revenues than selling it spot, the program will prevent 'money for nothing' schemes, where a participant can earn expected profits by selling inventoried energy forward, when it has no intention of actually maintaining inventoried energy for Inventoried Energy Days. By ensuring that selling forward is not expected to produce *lower* revenues than selling spot, it helps allow the forward settlement to be a viable mechanism by which participants can sell inventoried energy to potentially reduce their revenue uncertainty.[46]

To produce a spot rate that would provide approximately the same total program revenues that a participant would receive for selling the same amount of inventoried energy forward, the forward rate of $82.49 is divided by the expected number of Inventoried Energy Days per winter. Historical data indicates that approximately 10 Inventoried Energy Days per winter should be expected, and so the spot rate is calculated as $8.25 (after rounding to the nearest cent).[47] Dr. Geissler provides additional information and examples in his testimony, and explains the different advantages and risks associated with a participant's decision to sell forward versus spot, especially in cases where the number of Inventoried Energy Days differs from expectations.[48]

Importantly, Market Participants are free to choose how to manage such risks. As a threshold matter, participation in both the forward and spot components of the program is entirely voluntary. Furthermore, Market Participants can choose how much of their inventoried energy to sell forward, where deviations between the quantity maintained and that sold forward are settled at the spot rate. As a result, a Market Participant could choose not to sell any inventoried energy forward to avoid the risk of incurring spot charges for failing to meet its forward financial obligation, and it will then be compensated at the spot rate for every MWh of inventoried energy that it maintains for each Inventoried Energy Day. Alternatively, participants can choose to sell a portion of their potential inventoried energy forward, with the remainder being sold spot. This may reduce their risk if they do not expect to maintain their full inventoried energy quantity for each measurement, but also do not want to rely solely on the spot settlement (and the associated revenue uncertainty that comes with only being compensated if and when Inventoried Energy Days occur).[49]

---

[46] Geissler Testimony at 29.

[47] *See* Geissler Testimony at 29-31.

[48] *See* Geissler Testimony at 31-33.

[49] Geissler Testimony at 33-34.

4. Trigger Conditions

In the spot component of the program, a participant's inventoried energy will be measured (to determine its spot settlement) when the trigger conditions have been met. As explained previously, one of the program's objectives is to improve winter energy security by increasing the quantity of inventoried energy that is available to be converted into electric energy during stressed winter conditions. The program seeks to satisfy this objective, in part, by incenting resources to take actions to manage their inventories so that they can be converted to electric energy, if necessary, during times of system stress. The trigger conditions are intended to identify periods where the system is more likely to be stressed, so that the program will provide strong incentives for Market Participants to take actions to maintain inventoried energy when it is needed most.[50] As Dr. Geissler explains, it is also important that the trigger conditions be based on simple, objective, and transparent conditions that can be forecast using historical data, and that they be independent of ISO procedures, participant actions, and general market conditions.[51]

The interim program is triggered for any calendar day in the months of December, January, or February for which the average of the high temperature and the low temperature on that day, as measured at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit. Any such day is defined as an "Inventoried Energy Day" under the program.[52]

The trigger conditions rely on observed, rather than forecast, temperatures. As a result, whether a day was an Inventoried Energy Day will only be known definitively after the day's high and low temperatures have been determined. Consistent with this, program participants are required to report their inventoried energy to the ISO the morning after the conclusion of each Inventoried Energy Day. That reported inventory forms the basis for the participant's spot settlement.[53] Dr. Geissler provides additional details regarding the determination and application of these trigger conditions in his testimony.[54]

[50] Geissler Testimony at 34.

[51] Geissler Testimony at 34-36.

[52] Geissler Testimony at 36.

[53] Geissler Testimony at 36.

[54] *See* Geissler Testimony at 36-44.

5. Maximum Duration

Dr. Geissler indicates that it is not desirable for the program to compensate an unlimited amount of inventoried energy. If a resource has enough inventoried energy to operate for 12 hours and it adds another MWh of inventoried energy, this increment may improve the region's winter energy security by being converted to electric energy during stressed winter conditions. If, however, a resource has enough inventoried energy to operate for six months and it adds another MWh of inventoried energy, this act is unlikely to have a material effect on the region's winter energy security.[55]

To reflect that the incremental reliability benefit of another MWh of inventoried energy decreases as a resource maintains a greater quantity of inventoried energy, the program includes a maximum duration parameter of 72 hours. This maximum duration caps the quantity of inventoried energy that each resource can provide so that the program is not compensating participants for inventoried energy that is unlikely to be usable in the operational timeframe where it is more likely to improve winter energy security.[56]

The maximum duration caps the amount of inventoried energy that a resource can sell in the forward and spot settlements. For example, a resource with a maximum potential output of 100 MW would be permitted to sell up to 7,200 MWh in the program. Importantly, 72 hours does not represent a minimum quantity that is required to participate in the program. Rather, it serves as a cap on the inventoried energy quantity for which a resource is compensated. Resources with less inventoried energy than the quantity implied by this maximum duration will be compensated for the quantity they can maintain.[57] In his testimony, Dr. Geissler provides additional information about how the ISO chose the 72-hour maximum duration.[58]

D. Program Eligibility

1. General Eligibility

In determining what types of technologies and fuels will be eligible to sell inventoried energy under the interim program, Dr. Geissler explains that the ISO identified a set of three conditions that should be satisfied. First, this inventory can be converted to electric energy at the

[55] Geissler Testimony at 16.

[56] Geissler Testimony at 16-17.

[57] Geissler Testimony at 44-46.

[58] *See* Geissler Testimony at 46-47.

ISO's direction. The program seeks to buy inventoried energy that can be converted to electric energy at the ISO's direction during periods of system stress, if necessary, to provide winter energy security. It is therefore essential that this inventoried energy can be converted to electric energy as directed by the ISO during these periods of system stress.[59]

Second, the conversion of this inventoried energy to electric energy reduces the amount of electric energy the resource can produce in the future (before replenishment). By definition, inventoried energy is stored at present and can be converted into electric energy at a later period. As discussed earlier, a key contributor to the region's winter energy security concerns is the potential lack of inventoried energy available to be converted to electric energy during extended cold spells. This program seeks to ameliorate this concern by directly compensating resources that maintain inventoried energy, rather than convert it to electricity and reduce the inventory, thereby ensuring its availability during cold weather periods.[60]

Third, this inventoried energy can be measured by the participant, in MWh, and reported daily. As with any product for which Market Participants are compensated, they must be able to provide the ISO with settlement quality data that accurately reflects the quantity of the product delivered. Absent this requirement, Market Participants could be compensated at a level that was inconsistent with the quantity of inventoried energy that they maintained, which could lead consumers to pay for inventoried energy that was not actually available.[61]

Based on these three conditions, Dr. Geissler explains that oil, coal, nuclear, biomass, and refuse generators are generally eligible to participate in the inventoried energy program.[62] Some hydro and pumped-storage generators meet the three conditions identified earlier, and others do not. Generally, if the hydro generator has a pond or reservoir on site or upstream, and this resource can be dispatched by the ISO to convert this water into electric energy, and the amount of water available to be converted to electric energy can be measured by the participant and reported to the ISO, then the resource can be compensated for water that is stored in the pond or reservoir (subject to certain limitations related to upstream ponds or reservoirs).[63] An Electric Storage Facility can generally be credited with inventoried energy for the electric charge that it holds that can be converted into electric energy at the ISO's direction. Similarly, a storage system coupled with a wind or solar resource may also be credited with inventoried energy for

---

[59] Geissler Testimony at 48.

[60] Geissler Testimony at 49.

[61] Geissler Testimony at 49.

[62] *See* Geissler Testimony at 49-51.

[63] Geissler Testimony at 51-52.

the electric charge that it holds.[64] If a Demand Response Resource meets the three conditions discussed above and the fuel it uses meets the eligibility and reporting requirements for that fuel type, then it can be compensated under the program. For example, if the Demand Response Resource is a behind-the-meter fossil fuel generator that can follow ISO dispatch instructions and has on-site fuel that can be measured, it can be compensated under the program.[65] External resources, solar, wind, and settlement-only resources are generally not permitted to participate in the program.[66]

2. Participation of Natural Gas Resources

A natural gas resource can be compensated for inventoried energy under this program if it signs a contract for the firm delivery of gas that can be called on to produce electric energy at the ISO's direction. Such contracts generally satisfy the three conditions outlined above. This contract may be with one of the LNG facilities that serves the region, or it could instead be with a counterparty that does not source the gas at an LNG facility. To ensure that these contracts are likely to provide inventoried energy that improves the region's winter energy security, the program includes specific provisions that they must satisfy.[67]

Dr. Geissler explains that contracts for natural gas differ from other types of inventoried energy, as they are financial in nature, rather than physical. As a result, the measurement of the gas is based on the terms of the contract, rather than the actual quantity of fuel that is stored in the tank, pile, or pond and directly available to the generator. To increase the likelihood that gas contracts eligible for inventoried energy compensation represent gas that can be converted to electric energy in a manner similar to other forms of inventoried energy, and that will help to improve region's winter energy security, the program requires that they meet two additional conditions. First, this contract must allow for firm delivery of the gas and must include no limitations on when natural gas can be called during a day. Second, the contract must not require that the Market Participant incur incremental costs to exercise the contract that could be greater than 250 percent of the delivery period's average forward price.[68]

As to the first condition, which requires that the contract provide for firm delivery of the gas and must include no limitations on when natural gas can be called during a day, Dr. Geissler

[64] Geissler Testimony at 52.

[65] Geissler Testimony at 53.

[66] Geissler Testimony at 53-54.

[67] Geissler Testimony at 54.

[68] Geissler Testimony at 55.

explains that these provisions ensure that a contract for natural gas functions effectively like other types of inventoried energy.[69]

As to the second condition, which states that the contract must not require the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the delivery period's average forward price, Dr. Geissler notes that the program aims to increase the deliverable gas for electric generation on cold winter days where system conditions are more likely to be stressed. This condition seeks to address potential instances where a gas-fired generator signs a contract with very significant incremental costs of buying the gas. Under such contract terms, the contract counterparty may not have a strong financial incentive to take the necessary steps to ensure that the gas is actually available and deliverable if called because the likelihood that the gas is called is low. In such cases, the contracted gas may not actually improve the region's winter energy security, as the gas may not be available during the precise times when it is most likely to be called, where system conditions are stressed and the availability of additional gas for electric generation would potentially improve winter energy security. This condition therefore seeks to limit inventoried energy compensation for gas contracts to the set of contracts where the contract counterparty has a strong incentive to ensure that the gas is available and deliverable to the generator because the contract's incremental costs suggest it may be called.[70] In his testimony, Dr. Geissler provides additional details about how the 250 percent threshold was determined and its implementation.[71]

Dr. Geissler further explains that there is a cap on the total amount of inventoried energy that can be compensated under the program from gas contracts associated with LNG facilities that serve New England. Specifically, the quantity of inventoried energy associated with such contracts that can be compensated under the program is capped at 560,000 MWh. The program includes this cap because the amount of gas from LNG facilities that serve New England that can be delivered to electric generators in the region may be limited for several reasons, including the modest number of these gas facilities. The program's cap on the total inventoried energy associated with such gas injections reflects this physical limitation, and therefore reduces the possibility that more inventoried energy associated with these contracts is sold than can reasonably be expected to be deliverable during stressed winter conditions.[72] Dr. Geissler

[69] *See* Geissler Testimony at 56-57.

[70] Geissler Testimony at 57.

[71] *See* Geissler Testimony at 58-59.

[72] Geissler Testimony at 60.

provides additional details about how this cap was determined and how it will be implemented in his testimony.[73]

3. Other Issues Related to Program Eligibility

Dr. Geissler indicates that resources that were retained for reliability by the ISO and are being compensated via a cost-of-service agreement are not eligible to participate in this program. The program seeks to reduce the likelihood that a resource that provides winter energy security seeks to retire, and also aims to incent resources to take actions before and during the delivery period to improve the region's winter energy security. Resources that have a cost-of-service agreement have already indicated an intent to retire. And this program is unlikely to impact their decisions regarding inventoried energy as they do not participate in the region's competitive markets in a manner similar to other resources. Finally, it appears unlikely that such resources would have an incentive to participate in the inventoried energy program, as any program revenues are likely to offset their cost-of-service payments. Based on these observations, the ISO is excluding such resources from participating in the program.[74]

Dr. Geissler also notes that there is no requirement that a resource have a Capacity Supply Obligation to participate in the inventoried energy program. The program seeks to provide similar compensation for similar service. The service provided here is inventoried energy that can be converted into electric energy at the ISO's direction. This service, as defined by the three conditions described above, can be provided by resources that have a Capacity Supply Obligation as well as those that do not. The inventoried energy program therefore does not require such an obligation to be eligible to participate.[75]

E. Program Costs, Cost Allocation, and Program Impacts

1. Indicative Program Costs

Dr. Geissler states that the ISO contracted with Dr. Schatzki of the Analysis Group to provide a representative estimate of the program's total annual costs. This representative estimate assumes that: (i) all eligible non-gas resources sell their maximum quantity of inventoried energy forward and maintain this amount for each Inventoried Energy Day, and (ii)

[73] *See* Geissler Testimony at 60-64.

[74] Geissler Testimony at 65.

[75] Geissler Testimony at 65.

the total quantity of inventoried energy provided by gas resources is equal to 560,000 MWh, the cap quantity governing LNG-based contracts.[76]

Under these assumptions, Dr. Schatzki estimates representative program costs of $148 million per year. This corresponds to roughly 1.8 million MWh of inventoried energy sold forward and maintained for each Inventoried Energy Day. Because this estimate assumes that the quantity of inventoried energy associated with gas contracts is equal to the LNG-based inventoried energy cap quantity, it can be considered the representative 'upper bound' estimate.[77] This estimate is also discussed in more detail in the testimony provided by Dr. Schatzki with this filing.[78]

If the program does not incent resources to sign gas contracts, Dr. Geissler explains, the total quantity of inventoried energy would decrease by 560,000 MWh (the cap amount assumed in the 'upper bound' scenario), and this would produce program costs of approximately $102 million per year, where 1.2 million MWh of inventoried energy are sold. Because this estimate assumes no gas participation, it can be considered the representative 'lower bound' estimate.[79]

Dr. Geissler indicates, however, that actual program costs could fall above or below the upper and lower bound estimates. These cost estimates make several assumptions about program participation, resource performance, and winter severity that may not hold, which could lead to higher or lower annual program costs. First, these estimates assume that all non-gas resources choose to participate in the program. If some of these resources choose not to participate, program costs may be lower. On the other hand, if additional gas resources sign contracts that are not LNG-based, new resources enter the region, or existing resources make investments that allow them to hold more inventoried energy, program costs may be higher than estimated.[80]

Second, these estimates assume that the total quantity of inventoried energy maintained during each Inventoried Energy Day is equal to that sold forward. If this assumption is incorrect and resources participate in the program and sell their inventoried energy forward, but do not maintain this forward amount for each Inventoried Energy Day, this will result in spot charges to

---

[76] Geissler Testimony at 66.

[77] Geissler Testimony at 66-67.

[78] *See* Schatzki Testimony at 7-8.

[79] Geissler Testimony at 67.

[80] Geissler Testimony at 67.

these under-performing resources which will reduce the program's total cost (because these charges will result in a credit to consumers in the form of reduced program charges).[81]

Third, these estimates assume that all Market Participants choose to sell their inventoried energy forward. However, to the extent that participants instead choose to sell inventoried energy spot, program costs will tend to increase with the number of Inventoried Energy Days because payments for inventoried energy will be made to participants selling spot for each Inventoried Energy Day. Specifically, program costs will tend to be higher than those estimated if participants opt to sell inventoried energy spot rather than forward, and the number of Inventoried Energy Days during the delivery period is greater than ten (recall that a resource that sells spot earns higher program revenue than a resource that sells forward if the number of Inventoried Energy Days exceeds its historical average of ten). Similarly, if the number of Inventoried Energy Days during the delivery period is less than ten, this will produce lower total program costs.[82]

2. Cost Allocation

As Dr. Geissler explains, inventoried energy program costs will be allocated on a regional basis to Real-Time Load Obligation. This is consistent with how costs were allocated under the earlier winter reliability programs and with the retention of resources for fuel security.[83] The total costs associated with the forward sale of inventoried energy will be evenly distributed across each day in the December through February delivery period. The spot settlement could result in a net charge to load if the total inventoried energy maintained for the Inventoried Energy Day exceeds the quantity sold forward, or a net credit to load if the total inventoried energy maintained for the Inventoried Energy Day falls below the quantity sold forward. In either case, this charge or credit is assigned to Real-Time Load Obligation on the Inventoried Energy Day.[84]

3. Effects of the Program on other ISO Wholesale Markets

Dr. Geissler states that, consistent with the program's second design objective, it may reduce the likelihood that a resource that maintains inventoried energy that contributes to the

---

[81] Geissler Testimony at 68.

[82] Geissler Testimony at 68.

[83] *See* Order Accepting Compliance Filing and Requiring Informational Filings, 165 FERC ¶ 61,202 at PP 53-558 (issued December 3, 2018) (citing ISO New England Inc., 113 FERC ¶ 61,220 at P 7).

[84] Geissler Testimony at 69.

region's winter energy security seeks to retire. Mechanically, this objective is achieved by providing program revenues that allow such resources to reduce their de-list bid prices in the Forward Capacity Auction, thereby increasing the likelihood that they are awarded a Capacity Supply Obligation. Furthermore, the program introduces a new opportunity cost component to energy market offer prices during the program's delivery periods.[85]

To further achieve its second objective, Dr. Geissler continues, the program seeks to affect how resources with inventoried energy manage that inventory to improve the region's winter energy security. More specifically, the ISO would expect resources to take actions to maintain or replenish their inventory in anticipation of upcoming Inventoried Energy Days. In order to maintain their existing inventory, resources may include an opportunity cost in their energy market offers to reflect that converting inventoried energy into electric energy at present may reduce the quantity of inventoried energy that is credited under this program for upcoming Inventoried Energy Days, and that this reduction may result in lower program revenues.[86] This opportunity cost should therefore be calculated to ensure that the energy market payment that they would receive for converting this inventoried energy into electric energy at present is sufficiently high that it offsets any expected reduction in inventoried energy revenues that would occur.[87]

In his testimony, Dr. Geissler provides additional information and illustrations regarding how these opportunity costs may be calculated and the impacts on a resource's overall revenues under various scenarios.[88] He demonstrates that a resource that includes opportunity costs associated with the inventoried energy program in its energy market offer is not made worse off if its energy market offer is accepted and its inventoried energy is reduced as it is converted to electric energy.[89] Dr. Geissler also describes the actions that a Market Participant can take to reduce its opportunity costs and thereby increase its chances of earning both energy market revenues and compensation for inventoried energy.[90]

---

[85] Geissler Testimony at 69.

[86] The existing market rules allow for the inclusion of opportunity costs, such as those potentially introduced by the inventoried energy program, in energy market offers, and so no additional Tariff changes are needed in this filing regarding such opportunity costs. *See* Tariff Section III.A.7.5.1.

[87] Geissler Testimony at 70.

[88] *See* Geissler Testimony at 70-80.

[89] Geissler Testimony at 71-74.

[90] Geissler Testimony at 78-79.

Finally, Dr. Geissler explains how the inclusion of opportunity costs in energy market offers introduced by the inventoried energy program may change the order in which generators are called to meet demand. Resources with larger opportunity costs will increase their energy market offer prices, and these higher offer prices will make them less likely to clear. In their place, resources with limited or no opportunity costs are likely to be dispatched. Additionally, resources that can use either inventoried energy or non-inventoried energy to produce electric energy are more likely to use non-inventoried energy, as doing so does not potentially reduce their inventoried energy revenues. Relative to the status quo, this change in the supply stack will tend to decrease the likelihood that resources that have limited inventoried energy are dispatched using this fuel, thereby increasing the amount of inventoried energy available to the region and improving its winter energy security.[91]

Furthermore, the magnitude of this impact is not fixed, and instead responds to the expected likelihood of future Inventory Energy Days. Specifically, the size of the opportunity costs introduced by the inventoried energy program generally increases during periods when cold winter conditions are expected, and decreases when milder weather conditions are forecast. As a result, the changes to dispatch to maintain the region's inventoried energy are expected to be most significant precisely when stressed system conditions appear more probable and this inventoried energy is likely to provide the most reliability benefit.[92]

F. Program Participation and Reporting

Dr. Geissler also walks through a number of administrative details regarding participation in the inventoried energy program. These include what information must be submitted by Market Participants to the ISO before participating in the program and when,[93] what participation information will be posted by the ISO to its website,[94] and what information must be reported to the ISO and when after each Inventoried Energy Day.[95] Notably, to participate in the forward component of the program, participants must submit election information no later than October 1 before the winter period begins, while participants may elect to participate spot at any time before the end of the winter period.[96] Dr. Geissler also walks through provisions addressing

---

[91] Geissler Testimony at 79-80.

[92] Geissler Testimony at 80.

[93] Geissler Testimony at 81-85.

[94] Geissler Testimony at 86.

[95] Geissler Testimony at 86-92.

[96] Geissler Testimony at 84-85.

situations where resources share a fuel source,[97] where resources are partially or fully unavailable,[98] and where inventoried energy is not accessible.[99] Many of these details are also covered in the more detailed description of the Tariff revisions below.

V. DESCRIPTION OF SPECIFIC TARIFF REVISIONS

The Tariff provisions implementing the inventoried energy program will be contained in Appendix K to Market Rule 1. Appendix K currently describes the defunct "Winter Reliability Solutions." Those provisions are being deleted in their entirety and replaced with the rules for the inventoried energy program.

New Section III.K indicates that the ISO will administer the inventoried energy program for the two winters of 2023-2024 and 2024-2025, which are contained in the 14th and 15th Capacity Commitment Periods, respectively. The balance of new Appendix K is made up of four main sections:

- III.K.1 describes the information that a Market Participant must provide to the ISO before participating in the inventoried energy program;
- III.K.2 describes the forward payments that will be made to Market Participants electing and approved to participate in the forward component of the program;
- III.K.3 describes the spot payments that will be made to Market Participants electing and approved to participate in the spot component of the program; and
- III.K.4 describes how the inventoried energy program's cost will be allocated.

Each of these sections is discussed in turn below.

A. III.K.1 – Submission of Election Information

New Section III.K.1 states that participation in the inventoried energy program is voluntary, but that in order to participate, certain information must first be submitted to and approved by the ISO. For Market Participants electing to participate in the forward component of the program (and hence also in the spot component), this information must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each of the two winter periods during which the program

[97] Geissler Testimony at 88-89.

[98] Geissler Testimony at 90.

[99] Geissler Testimony at 90-92.

will be in place). For Market Participants electing to participate only in the spot component of the program, this information may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

New Section III.K.1(a) requires a Market Participant to list the assets that will participate in the program and to provide information about each, including the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site or otherwise credited under the program; and a list of other assets that share the fuel inventory. The subsection further indicates that Settlement Only Resources, assets not located in the New England Control Area, assets being compensated pursuant to a cost-of-service agreement, and assets that cannot operate on stored fuel (or pursuant to a qualifying contract) at the ISO's direction may not participate in the program, but that Demand Response Resources with Distributed Generation may.

New Section III.K.1(a) also requires that, for any asset that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must detail a number of specific terms, including all terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas. As required of all assets participating in the program, the contract must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period.

New Section III.K.1(b) requires each Market Participant to submit a detailed description of how its energy inventory will be measured after each Inventoried Energy Day and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than based on the efficiency with which the assets convert fuel to energy, this description should explain and support that alternate allocation.

New Section III.K.1(c) simply requires the Market Participant to indicate whether it is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

New Section III.K.1(d) requires each Market Participant that elects to participate in the forward component of the program (and hence also in the spot component) to indicate the number of MWh it wishes to sell forward. This "Forward Energy Inventory Election" may be any amount up to the total of the combined MW output of the Market Participant's listed assets for the maximum program duration of 72 hours (and as further limited by the amount of fuel that can actually be stored on site or otherwise credited under the program). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must also indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of the Market Participant's Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election").

New Section III.K.1.1 provides for the ISO's review and approval of each Market Participant's submitted information. The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program.[100] Section III.K.1.1(a) imposes the limitation that a contract for natural gas must not require the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the delivery period's average forward price, and Section III.K.1.1(b) imposes the 560,000 MWh program cap on the quantity of LNG-based inventory that can be compensated under the program, both as described in detail above and in the Geissler Testimony.

New Section III.K.1.2 states that as soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

B. III.K.2 – Forward Payments

New Section III.K.2 provides for the forward (or "base") payments under the program. It states that a Market Participant participating in the forward component of the program (and hence also in the spot component) shall receive a payment for each day of the months of December, January, and February. Each such payment shall be equal to the Market Participant's Forward Energy Inventory Election (as adjusted pursuant to the ISO review and approval

---

[100] Section III.K.1.1 further provides that for election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

process) multiplied by the forward rate of $82.49 per MWh and divided by the total number of days in those three months.

C. III.K.3 – Spot Payments

New Section III.K.3 provides for the spot payments under the program; that is, the payment associated with each Inventoried Energy Day. Each Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive this payment (which may be positive or negative).

New Section III.K.3.1 defines an Inventoried Energy Day as any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

New Section III.K.3.2 describes how the spot payment for each Inventoried Energy Day will be calculated. Specifically, a Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the amount of inventory maintained by the Market Participant for the Inventoried Energy Day (its "Real-Time Energy Inventory") minus its Forward Energy Inventory Election, with the difference multiplied by the spot rate of $8.25 per MWh. (The forward elected amount is subtracted here because, in this two-settlement construct, the spot payment is based on the positive or negative deviation from the forward position. Market Participants that did not sell forward will have a forward position of zero, and so for those participants, nothing will be subtracted from the Real-Time Energy Inventory, and the spot payment cannot be negative.)

New Section III.K.3.2.1 states that a Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day will be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted to account for the Market Participant's ownership share of each asset).

New Section III.K.3.2.1.1 describes how each asset's Real-Time Energy Inventory for an Inventoried Energy Day will be determined. Subsection (a) requires the Market Participant to measure and report to the ISO the Real-Time Energy Inventory for each of its assets between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the asset's fuel type. Subsection (a) then provides additional details regarding the units and other measurement requirements specific to each of the various types of fuel inventory that are eligible for compensation under the program. Pursuant to new Section III.K.3.2.1.1(b), if a Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

New Section III.K.3.2.1.1(c) requires Market Participants to limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations), to prevent payment for measurable fuel inventory that cannot actually be converted to electric energy.

New Section III.K.3.2.1.1(d) indicates that a Market Participant's submitted Real-Time Energy Inventory information is subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program. Pursuant to new Section III.K.3.2.1.1(e), the ISO will incorporate the results of any such verification in determining an asset's final Real-Time Energy Inventory. In determining this final amount, subsection (e) also requires the ISO to allocate shared fuel inventory appropriately among assets, to account for any asset outages on the Inventoried Energy Day, and to impose the program's 72 hour durational limit.

Finally, new Section III.K.3.2.1.2 sets forth how the 560,000 MWh cap on the quantity of LNG-based inventory that can be compensated under the program is implemented in the spot component of the program, as described in detail above and in the Geissler Testimony.

D. III.K.4 – Cost Allocation

New Section III.K.4 states that costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day. As discussed above, this allocation is consistent with Commission precedent.

VI. STAKEHOLDER PROCESS

The Tariff revisions filed here were discussed extensively with stakeholders at meetings from November 2018 through March 2019. At its March 5, 2019 meeting, the NEPOOL Markets Committee voted against recommending that the NEPOOL Participants Committee support these Tariff revisions, with a vote of 42.29 percent in favor. At its March 13, 2019 meeting, the NEPOOL Participants Committee did not support these revisions, with a vote of 32.67 percent in favor.

The final version of the inventoried energy program filed here reflects important changes that were made in response to concerns expressed by stakeholders. Ultimately, however, stakeholders did not support the program. While there were varied reasons for the lack of support, there were some broad themes. Representatives of those who will pay the costs of the program felt that it was too expensive relative to the potential benefits, especially with respect to the number and types of resources compensated. For their part, generators felt that the program does not go far enough, and were especially concerned that the revenue provided by the program would be offset by lower capacity market payments. The ISO expects that these concerns will be fully aired in responsive pleadings.

VII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept these Tariff changes as filed, without suspension or hearing, to be effective on May 28, 2019. The inventoried energy program will provide compensation in the winters of 2023-2024 and 2024-2025, which fall within the Capacity Commitment Periods beginning on June 1, 2023 and June 1, 2024, respectively. The Forward Capacity Auctions for those commitment periods will be conducted in February 2020 and February 2021. Having the program in place during the resource qualifications periods for those Forward Capacity Auctions will appropriately allow Market Participants to consider and incorporate potential revenue from the program into the de-list bids that they might submit in those auctions.[101]

---

[101] The deadline for submitting retirement de-list bids and permanent de-list bids for the Forward Capacity Auction to be conducted in February 2020 was March 15, 2019. Because the potential revenue from the inventoried energy program would be relevant in formulating those bids, and in light of the fact that the rules were not yet filed or approved by the Commission, the Internal Market Monitor encouraged Market Participants to submit two versions of any such bids due on March 15 – one version assuming the inventoried energy program is in place and one version assuming it is not.

VIII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Tariff revisions filed here do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations.[102] Notwithstanding its request for waiver, the ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

35.13(b)(1) – Materials included herewith are as follows:

- This transmittal letter;
- Testimony of Christopher Geissler;
- Testimony of Todd Schatzki;
    - Attachment A: Todd Schatzki Curriculum Vitae;
    - Attachment B: Analysis Group memorandum "Calculation of Rate for Interim Compensation Program;"
- Blacklined Tariff sections effective May 28, 2019;
- Clean Tariff sections effective May 28, 2019; and
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Part VII above, the ISO requests that the Tariff revisions filed here become effective on May 28, 2019.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/participate/participant-asset-listings. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In

[102] 18 C.F.R. § 35.13 (2016).

accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in Part VIII of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Part IV of this transmittal letter.

35.13(b)(6) – The ISO's approval of these changes is evidenced by this filing.

35.13(b)(7) – The ISO has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

35.13(c)(1) – The Tariff changes herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the wholesale, resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions filed herein.

IX. CONCLUSION

For the reasons set forth above, the ISO requests that the Commission accept the Tariff changes filed here with an effective date of May 28, 2019.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: */s/ Maria Gulluni*

Maria Gulluni, Esq.
Kerim P. May, Esq.
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4551
E-mail: kmay@iso-ne.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket No. ER19-_____-000
	)	
	)	

TESTIMONY OF CHRISTOPHER GEISSLER
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Christopher Geissler. I am an Economist working in the Market Development Department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: Please describe your responsibilities, work experience, and educational background.

A: My primary responsibilities at the ISO include wholesale electricity market design and development. Among my notable, relevant experience, I served as the project lead in designing the demand curves used in the Forward Capacity Market, which help align the region's procurement of capacity with its marginal reliability impact; I served as the project lead in designing a substitution auction that helps to accommodate state-supported policy resources in the region's wholesale markets while maintaining competitively-based capacity prices (the competitive auctions with sponsored policy resource, or

"CASPR," project); and I served as the ISO's lead economist in evaluating the price treatment of resources retained for fuel security in the Forward Capacity Market. I am also an instructor for numerous market-related sections of the ISO's Wholesale Energy Markets courses for ISO staff and Market Participants.

Prior to joining the ISO in 2013, I received an M.A. and Ph.D. in Economics from Duke University, where I conducted research on competition in regulated industries.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain the rationale for and design of the inventoried energy program that the ISO will administer for the winters of 2023-2024 and 2024-2025. This interim program will compensate resources for maintaining inventoried energy during cold winter conditions, when such inventoried energy is most likely to improve the region's energy security.

Q: How is your testimony organized?

A: The remainder of my testimony is organized as follows:

- In Part III, I will discuss the background leading to the development of the inventoried energy program and will describe the program's objectives.
- In Part IV, I will provide an overview of the inventoried energy program.

- In Part V, I will discuss the two-settlement structure of the program, and explain how the forward and spot rates were determined.
- In Part VI, I will explain the criteria determining when the spot component of the program is triggered.
- In Part VII, I will discuss the durational limit on the amount of inventoried energy that can be compensated under the program.
- In Part VIII, I will provide details about eligibility for the inventoried energy program.
- In Part IX, I will provide information about the cost of the program and its potential impacts on the energy market.
- In Part X, I will detail the participation and reporting mechanics of the program.

III. BACKGROUND AND OBJECTIVES OF THE INVENTORIED ENERGY PROGRAM

Q: Why is the ISO implementing an inventoried energy program for the winters of 2023-2024 and 2024-2025?

A: As the Commission is aware, the ISO and stakeholders are working diligently to design and implement a long-term, market-based solution to address concerns about New England's winter energy security. (The Commission directed the ISO to undertake such an effort in an order issued on July 2, 2018 in Docket No. EL18-182-000.) That long-term solution will be filed with the Commission in 2019, and has a targeted implementation coincident with the Capacity Commitment Period that begins on June 1,

2024. The Forward Capacity Auction for that commitment period will be conducted in February 2021.

In conjunction with this effort, the ISO also committed (in its August 31, 2018 filing in Docket No. EL18-182-000) to working with stakeholders to identify an interim approach that could be in effect before the Forward Capacity Auctions to be conducted in February 2020 and February 2021 (for the Capacity Commitment Periods beginning on June 1, 2023 and June 1, 2024, respectively). Although the full, market-based approach will take time to develop and implement, the simpler, interim approach filed here can be in place before the Forward Capacity Auction to be held in February 2020. Hence, the interim program filed here will serve as a bridge to the long-term solution by providing incremental compensation to resources providing winter energy security starting in December 2023.

This will benefit resources that provide winter energy security, but takes on increased importance in the case of any resources that might be considering retirement before the benefits of the full, market-based approach can be realized. Retirement de-list bids for the Forward Capacity Auction to be conducted in February 2020 (for the commitment period beginning in 2023) were due to the ISO on March 15, 2019. The interim program filed here was vetted extensively with Market Participants over recent months, and the ISO has communicated clearly its intent to file this program with the Commission and, if it is approved, to have this program in place for the winters of 2023-2024 and 2024-2025. This notice has allowed participants to consider the potential incremental revenue that the program could provide during the 2023-2024 winter in making their decision as to whether, or at what price, to seek to retire in the February 2020 Forward Capacity Auction. In this way, providing compensation through an interim program might forestall the retirement (or out-of-market retention) of a resource that would be economic but for the absence of such compensation, a desirable outcome for the ISO and the region.

Q: How did you approach the design of this interim program?

A: At a high level, the ISO identified a number of design objectives that it sought to satisfy when developing the interim program. First, in order to have the interim program in place in time to potentially be reflected in retirement de-list bids for the February 2020 Forward Capacity Auction, the interim program must be simple enough to be designed and filed quickly, and not overly complex to implement. Second, to be effective, the program should compensate resources that provide winter energy security, and thereby improve the region's reliability during stressed winter conditions relative to the status quo where no such program is in place. And third, like all such initiatives, it should be designed consistent with sound market design principles, most notably providing similar compensation for similar service.

Q: Would it be possible to design a program that fully satisfies all of these design objectives?

A: Unfortunately, it does not appear possible to fully harmonize these particular design objectives. The most significant tension among these objectives is between developing a program that is simple enough to be designed and filed quickly and developing a program that is fully consistent with sound market design principles. Given the interim nature of the program, and because it must be in place soon to have its intended effect, priority has been given to simplicity and to ensuring that the program provides similar compensation for similar service.

Q: Please describe each of these design objectives, and the interplay between them, in more detail.

A: The first objective is that the program had to be simple enough that: (i) it could be designed and filed by the ISO quickly; and (ii) Market Participants can reasonably forecast potential revenue from the program when making retirement decisions. As a threshold matter, an interim program would be ineffective if it could not be in place before the full, long-term solution. And if it is to reduce the likelihood that otherwise economic resources that improve energy security retire (which I discuss next), the program must be understood by Market Participants before any retirement decisions are finalized. Furthermore, because the program is only scheduled to be in place for two winters, it is practical to prioritize simplicity when considering design options and their corresponding implementation requirements. Simplicity in both the design and implementation of this interim program will better allow the ISO to make progress on its longer-term, market-based approach to energy security.

The second objective is to compensate resources that provide winter energy security, and thereby improve the region's reliability during stressed winter conditions relative to the status quo where no such program is in place. This objective can be satisfied through two different mechanisms. First, the compensation provided by the program may incent resources to take actions that they otherwise would not take that improve the region's winter energy security. Second, this objective can be satisfied if the compensation provided by the program deters resources that provide winter energy security during stressed winter conditions from pursuing retirement, thereby reducing the likelihood that such resources and their reliability attributes exit the market or are retained through out-of-market actions that may adversely impact the wholesale markets.

The third objective is adherence to sound market design principles. The ISO seeks to satisfy sound market design principles in all cases where it is establishing a new product or modifying an existing product. These sound market design principles include: specifying a clearly defined product or attribute, transparently pricing the product or attribute, incenting Market Participants to deliver the product or attribute in a cost-effective manner, and settling any forward sale of the product or attribute against its spot delivery. A particularly important design principle is that the framework should strive to be technology-neutral by providing similar compensation for similar service.

As I indicated above, these objectives are fundamentally in tension. The first objective – that the design be simple enough to be in place in time to potentially influence near-term retirement decisions – is paramount here. The ISO and stakeholders are already hard at work on a full, market-based solution to the region's energy security issues, but that solution will require more time to design and implement. There is little reason to pursue an interim solution that cannot provide compensation for resources providing winter energy security before that long-term solution is in place.

The primary casualty of the interim program's adherence to simplicity is the third objective – following each of the sound market design principles. Fully incorporating those principles would add significant complexity to the program. For example, it would require a robust specification of demand for the desired reliability attribute. And it would require the development of a mechanism, such as the introduction of a new auction or significant changes to an existing auction, to buy this product from the set of suppliers that could sell it at lowest cost. Such features would require significant additional design work that would not have allowed the ISO to complete the design in time to potentially influence retirement decisions for the upcoming Forward Capacity Auction to be conducted in February 2020. Furthermore, such features would add complexity to the implementation process, which could jeopardize the ISO's ability to implement the interim program for the winter of 2023-2024.

One market design principle not being compromised here, however, is ensuring that the program provides similar compensation for similar service. This property is a bedrock of market design, and is generally consistent with the ISO's endeavors to compensate Market Participants in a technology-neutral manner. The interim program strives to ensure that all providers of inventoried energy are similarly compensated.

Finally, as to the objective of improving winter energy security during stressed conditions, the interim program being filed here is directionally correct. The program will create incentives for resources to take actions that increase their inventoried energy during periods of system stress, and these actions may improve the region's winter energy security. Additionally, the revenue that the program is likely to provide to resources that improve winter energy security through the maintenance of inventoried energy should decrease the likelihood that such resources pursue retirement, which may help to ameliorate the region's winter energy security concerns. The ISO cannot guarantee, however, that the program will incent specific resources to take precise actions that improve winter energy security or deter any particular resource that would otherwise be economic from retiring. To achieve such outcomes, the design would need to fully specify the value of the winter energy security attributes that are currently not being compensated. And again, to do so would require a program that fully specifies the region's demand for these attributes, which would add significant complexity and likely undermine meeting the paramount objective of simplicity and timeliness.

The ISO believes that the interim program being filed here appropriately balances these competing objectives and serves as a bridge to the full, market-based solution. Throughout the balance of my testimony, I will highlight design features and decisions that were informed by these objectives.

Q: You have emphasized the importance of having the interim program in place as soon as possible. Please explain the timing considerations in more detail.

A: If the interim program is to discourage potential retirements from otherwise economic resources that provide winter energy security – thereby helping to meet the second objective I mentioned above – it must be in place before those retirement decisions are made. The Forward Capacity Market rules generally require that a resource notify the ISO of its intent to retire approximately four years before actually discontinuing operations. In fact, retirement de-list bids for the next Forward Capacity Auction, which will be conducted in February 2020, were due to the ISO on March 15, 2019, and any resulting retirements would likely occur on June 1, 2023 (the start of the Capacity Commitment Period that is associated with the February 2020 Forward Capacity Auction).

Having this program vetted by stakeholders, with the understanding that the ISO will file it with the Commission in time for the February 2020 Forward Capacity Auction, has allowed resources to consider the program's potential incremental revenue during the 2023-2024 winter in making their decision as to whether, or at what price, to submit retirement de-list bids in the February 2020 Forward Capacity Auction (and thus potentially seeking to retire beginning in the 2023-2024 Capacity Commitment Period).

IV. OVERVIEW OF THE INVENTORIED ENERGY PROGRAM

Q: Why is inventoried energy the focus of the program, and how is it defined?

A: A key contributor to the region's winter energy security concerns is its reliance on electric energy from gas-fired resources that rely on the gas delivery from the interstate pipeline network, which can become constrained during winter cold spells. The potential lack of inventoried energy available to be converted to electric energy during such winter cold spells where system conditions are stressed could potentially lead to loss of load events. This program seeks to reduce this concern by directly compensating resources for maintaining inventoried energy that can then be converted into electric energy during such cold spells. Consistent with the second objective described above, this financial incentive may help to address the region's winter energy security concerns in the short term by incenting resources in the region to maintain greater inventoried energy levels than would otherwise occur absent the program, and by reducing the likelihood that resources with inventoried energy pursue retirement before the implementation of the full, market-based solution.

The program defines inventoried energy as fuel or potential energy that a resource can convert to electric energy at the ISO's direction. This definition generally allows resources that use a broad set of fuels to participate in the program. For example, if an oil resource has an on-site tank containing enough oil to operate the resource for two days, that resource has two days of inventoried energy.

Q: How may the program incent the region to maintain greater inventoried energy levels than would otherwise occur?

A: The program will compensate resources that maintain inventoried energy that can be converted to electric energy at the ISO's direction during cold winter conditions. There are several reasons that this may lead the region to maintain greater inventoried energy levels. First, the program may incent Market Participants to acquire more inventoried energy than they otherwise would absent the program. Direct compensation for inventoried energy may lead a resource to arrange for more inventoried energy at the start of the winter, as this incremental inventory may increase its expected inventoried energy revenues. Furthermore, as a resource depletes its inventory, the resource may consider replenishing its stock of inventoried energy to earn greater program revenues during cold winter conditions that occur later in the winter.

Second, this interim program may change if and when this inventoried energy is converted to electric energy, allowing it to be available for stressed winter conditions that occur later in the season. Specifically, the program creates a potential opportunity cost associated with converting inventoried energy into electric energy, as this conversion reduces a resource's remaining inventoried energy, and this may therefore decrease its program revenues going forward. As a result, resources that generate electricity by converting inventoried energy to electric energy are likely to include an opportunity cost that increases their energy market offer price. This in turn will tend to reduce the likelihood that such resources are dispatched, and increase the likelihood that resources that do *not* use inventoried energy (or that have a significant stock of inventoried energy, and thus have little or no opportunity cost associated with using it now) are dispatched in their place. This effect on dispatch will help maintain the region's inventoried energy so that it is available later in the winter if system conditions are stressed. The program's impact on the energy market dispatch, and a more detailed discussion of opportunity costs are included in Part IX.C below.

Third, because the program will provide incremental revenue to resources that maintain inventoried energy during stressed winter conditions (and hence reduce the amount of revenue those resources must recover through the capacity market), it may therefore decrease the likelihood that such resources seek to retire. The continued operation of such resources will contribute to the region's winter energy security.

Q: What are the main elements of the inventoried energy program?

A: The program consists of five core components that work together to provide compensation for resources that maintain inventoried energy during stressed winter conditions. These five components are: (1) the two-settlement structure; (2) the forward rate; (3) the spot rate; (4) the trigger conditions; and (5) the maximum duration.

Q: Please describe the first component – the two-settlement structure.

A: The interim program employs a two-settlement structure to determine program settlements. Participation in the inventoried energy program is voluntary, and a Market Participant may elect to participate in both the forward and spot components of the program, or only in the spot component of the program. A Market Participant electing to participate in both the forward and spot components is paid the forward rate for each MWh of inventoried energy that is sold forward. The spot rate is then applied to deviations between the MWh of inventoried energy maintained for each trigger condition and the MWh of inventoried energy sold forward.

For Market Participants electing to participate in both the forward and spot components of the program, these deviations can be positive or negative. A positive deviation for a trigger condition indicates that the participant maintained more inventoried energy for this event than it sold forward and will result in a positive spot settlement. A negative deviation occurs if the Market Participant sold more inventoried energy forward than it maintained for a trigger condition and requires that the participant 'buy out' of the unmet forward position at the spot rate, resulting in a negative spot settlement.

For Market Participants electing to participate in only the spot component of the program, any inventoried energy maintained for a trigger condition is compensated at the spot rate. Such resources are treated as having a zero forward position, such that any inventoried energy maintained for a trigger condition represents a positive deviation, and such a participant's settlement can only be positive (or zero). Part V.A of this testimony discusses the two-settlement structure in more detail.

Q: Please describe the second component – the forward rate.

A: For a Market Participant that elects to participate in both the forward and spot components of the program, the forward rate represents the payment rate that the Market

Participant receives in exchange for selling its inventoried energy forward for the entire winter season. By selling its inventoried energy forward, the resource must either maintain this quantity of inventoried energy for each trigger condition in the winter period, or buy out of this forward position at the spot rate. The program specifies a fixed forward rate of $82.49 for the entire delivery period for each MWh sold forward. The rationale behind this rate is discussed in more detail in Part V.B of this testimony.

Q: Please describe the third component – the spot rate.

A: For all Market Participants electing to participate in the inventoried energy program, the spot rate represents the payment rate that is applied to deviations between their inventoried energy maintained for each trigger condition, and that sold forward. For example, a resource that does not sell any inventoried energy forward will get paid the spot rate for each MWh of inventoried energy maintained each time the trigger conditions are met. This spot rate is set at $8.25 per MWh for each trigger condition in the delivery period, and it is derived from the forward rate. Further discussion of this rate and how it is derived is included in Part V.C of this testimony.

Q: Please describe the fourth component – the trigger conditions.

A: In the spot component of the program, a participant's inventoried energy will be measured (to determine its spot settlement) when the trigger conditions have been met. Consistent with the program's aim of compensating resources for maintaining inventoried energy that may improve the region's winter energy security, the trigger conditions correspond with periods where the system is more likely to be stressed due to severe cold weather conditions, and inventoried energy could therefore contribute to the region's winter energy security. In the spot settlement of this program, each resource's inventoried energy will be measured shortly after these trigger conditions occur, and its spot revenue will be based on the quantity of inventoried energy maintained for the triggering event and how it compares to its forward position. Specifically, the program will treat a day as a trigger condition (an "Inventoried Energy Day") if it occurs in December, January, or February, and the average of the high and low temperatures on the day is less than or equal to 17 degrees Fahrenheit. I will discuss the specifics of the trigger condition criteria and the rationale behind them in more detail in Part VI of this testimony.

Q: Please describe the fifth component – the maximum duration.

A: It is not desirable for the program to compensate an unlimited amount of inventoried energy. If a resource has enough inventoried energy to operate for 12 hours and it adds another MWh of inventoried energy, this increment may improve the region's winter energy security by being converted to electric energy during stressed winter conditions. If, however, a resource has enough inventoried energy to operate for six months and it adds another MWh of inventoried energy, this act is unlikely to have a material effect on the region's winter energy security.

To reflect that the incremental reliability benefit of another MWh of inventoried energy decreases as a resource maintains a greater quantity of inventoried energy, the program includes a maximum duration parameter. This maximum duration caps the quantity of inventoried energy that each resource can provide so that the program is not compensating participants for inventoried energy that is unlikely to be usable in the operational timeframe where it is more likely to improve winter energy security. The program uses a 72 hour maximum duration, and I will discuss the rationale behind this maximum duration in more detail in Part VII of this testimony.

Q: Can you please provide a simple numerical example illustrating how the program works?

A: Yes. Imagine that Resource A is an oil-fired generator that has a maximum potential output of 100 MW and has an on-site oil tank that can hold enough oil for the generator to run at its maximum potential output for 240 hours (10 days).

Q: What is the maximum quantity of inventoried energy for which Resource A can be compensated?

A: If Resource A's tank was full, it could convert this oil into 24,000 MWh of electric energy (100 MW × 240 hours). However, recall that the program's maximum duration caps a resource's inventoried energy for which it can be compensated at 72 hours. As a result, Resource A can sell no more than 7,200 MWh of inventoried energy (100 MW × 72 hours) in total between the forward and spot components of the program.

Resource A's compensation under the program will depend on a number of factors, including: (i) how much inventoried energy it sells forward; (ii) how much inventoried energy it maintains during each Inventoried Energy Day; and (iii) how many Inventoried

Energy Days occur. The impact of each of these factors on its total program compensation is discussed below.

V. TWO-SETTLEMENT STRUCTURE; FORWARD AND SPOT RATES

A. Two-Settlement Structure

Q: Please describe the program's two-settlement structure at a high level.

A: As previously mentioned, participation in the inventoried energy program is voluntary, and a Market Participant may elect to participate in both the forward and spot components of the program, or in only the spot component of the program. A Market Participant electing to participate in both the forward and spot components is paid the forward rate for each MWh of inventoried energy that is sold forward. The spot rate is then applied to deviations between the MWh of inventoried energy maintained for each Inventoried Energy Day and the MWh of inventoried energy sold forward.

For Market Participants electing to participate in both the forward and spot components of the program, these deviations can be positive or negative. A positive deviation for an Inventoried Energy Day indicates that the participant maintains more inventoried energy for that day than it sold forward. In such instances, the spot settlement will be positive and equal to the spot rate times the difference between the MWh maintained for the Inventoried Energy Day and the MWh sold forward. This payment reflects that the participant is providing incremental inventoried energy beyond what it sold forward for the Inventoried Energy Day, and this additional inventoried energy is likely to improve the region's winter energy security. A negative deviation occurs if the Market Participant sells a greater MWh of inventoried energy forward than it maintains for an Inventoried Energy Day. In such instances, the participant is required to 'buy out' of the unmet forward position at the spot rate to reflect that it is providing less inventoried energy than it sold forward, and this may adversely impact the region's winter energy security.

As mentioned previously, for Market Participants electing to participate in only the spot component of the program, any inventoried energy maintained for an Inventoried Energy Day is compensated at the spot rate. Such resources are treated as having a zero forward position, such that any inventoried energy maintained for an Inventoried Energy Day represents a positive deviation, and such a participant's settlement can only be positive (or zero).

Q: What obligation does a Market Participant take on with a forward sale of inventoried energy?

A: As is standard in two-settlement structures, a participant electing to sell inventoried energy forward will get paid the forward rate for each MWh sold forward – this corresponds with the 'first settlement' in the two-settlement structure. In exchange for this payment, the participant takes on a financial obligation associated with this forward sale to maintain the MWh amount the participant elected forward for each Inventoried Energy Day during the December through February period of the program. This financial obligation is enforced through a 'second settlement' that settles any deviation from the quantity of inventoried energy sold forward at the spot price. Specifically, this second settlement is equal to the product of the Market Participant's deviation between its actual spot delivery of the product (which is also capped at 72 hours of its maximum potential output) and its forward obligation, and the spot price.

Positive deviations, where the Market Participant's delivery of inventoried energy for an Inventoried Energy Day exceeds its forward position, correspond with a positive payment in the second settlement, reflecting that the participant provided more inventoried energy than was obligated in its forward sale. Negative deviations, where the Market Participant's delivery of inventoried energy for an Inventoried Energy Day falls short of its forward sale, correspond with a negative payment (or charge) in the second settlement. If the participant's delivery of inventoried energy for an Inventoried Energy Day is exactly equal to its forward sale, the second settlement is $0 because there is no deviation.

Q: Can you provide some examples illustrating how the two-settlement design works?

A: Yes. I provide two examples below. In the first, the resource 'over-performs,' meaning it provides more inventoried energy for each Inventoried Energy Day than it sold forward. In the second, it 'underperforms' and maintains less inventoried energy for each Inventoried Energy Day than sold forward. These examples use the program's forward rate of $82.49 per MWh and spot rate of $8.25 per MWh (which are discussed in more detail below), and assume that Resource A sells 1 MWh of inventoried energy forward. Resource A will therefore get paid $82.49 for the winter period in its first settlement for this forward sale ($82.49/MWh × 1 MWh). Its second settlement will depend on two factors: (a) the number of Inventoried Energy Days that occur, and (b) the quantity of inventoried energy that it maintains for each of those days.

First, consider an instance where the resource ‘over-performs.’ Assume that there are a total of ten Inventoried Energy Days during the relevant period, and for each, Resource A maintains 3 MWh of inventoried energy. Because Resource A sold 1 MWh of inventoried energy forward, it has a financial obligation to maintain 1 MWh for each Inventoried Energy Day (10 MWh total across the ten events), or buy out of this forward position at the spot rate. If it actually maintains 3 MWh for each event, its positive deviation for each event is 2 MWh, yielding a spot payment of $16.50 per Inventoried Energy Day ($8.25/MWh × 2 MWh). Summing across all ten days yields a net positive deviation of 20 MWh. This will result in total spot payments of $165.00 ($8.25/MWh × 20 MWh). In this case, Resource A’s net program revenues would be equal to $247.49, the sum of its forward and spot settlements.

Next, consider a case where Resource A instead ‘underperforms.’ Imagine that despite selling 1 MWh forward, Resource A does not provide any inventoried energy for each of the ten Inventoried Energy Days. In this case, the reported inventoried energy on each day is 0 MWh, and the inventoried energy deviation on each day is -1 MWh. Its net inventoried energy across the ten events is 0 MWh, for a cumulative negative deviation of -10 MWh. This will lead to spot payments for each Inventoried Energy Day of -$8.25 ($8.25/MWh x -1 MWh), and total spot payments for the relevant period of -$82.50 ($8.25/MWh × -10 MWh). Resource A’s net program revenues would be equal to -$0.01, the sum of its forward and spot settlements, as its spot charges fully offset its forward payment.

<u>B. Forward Rate</u>

Q: What does the forward rate represent?

A: The forward rate represents the payment that a Market Participant receives for each MWh of inventoried energy sold forward. In exchange for this compensation, the Market Participant takes on a financial obligation to maintain its elected amount of inventoried energy for each Inventoried Energy Day during the program delivery period (December through February).

Q: How is the forward rate determined?

A: The forward rate is an estimate of the minimum rate that would incent a gas-only resource to sign a winter peaking supply contract for vaporized liquefied natural gas ("LNG"). Consistent with the second objective, the availability of such LNG may increase the region's inventoried energy and improve winter energy security during stressed winter conditions.

Q: Why is the forward rate set at the minimum rate that would incent a gas-only resource to sign a winter-peaking supply contract?

A: When a service is competitively procured via a market-based mechanism such as an auction, the price is often set to the marginal participant's as bid costs of providing the service. This can be observed in the pricing rules employed to set energy market prices and capacity prices in New England, where the market clearing price is often set to the marginal energy or capacity supplier's offer price.

While the interim program instead sets this rate administratively, it uses the estimated minimum value that would incent program participation from a gas-only resource. This administrative rate is therefore intended to approximate the price that would occur if inventoried energy was competitively procured through a market-based mechanism where a gas-only resource that bids its 'break-even' price (that is, the price at which it was indifferent between providing the service and not) was the marginal resource that established the price paid to all resources providing the service.

Q: Why is the administrative rate based on the incremental costs of program participation for a gas-only resource, rather than the incremental costs associated with another type of resource?

A: The program seeks to compensate all resources that provide inventoried energy, regardless of fuel type. However, in providing this reliability attribute, different types of resources are likely to incur different incremental costs (and would therefore have different 'break-even' prices). For example, generators that typically have at least 72 hours of inventoried energy on-site during the winter even without this program are unlikely to incur significant incremental costs to participate in this program and would likely have a low 'break-even' price.

Gas-only resources, on the other hand, may incur significant costs to maintain inventoried energy, as they must sign a contract for firm gas to participate in the interim program. Incenting some gas-only resources to sign such contracts when they otherwise would not may significantly improve the efficacy of the inventoried energy program, as this is likely to improve winter energy security relative to the alternative where they do not take such actions. To provide sufficient incentives for gas resources to sign such contracts, the program must therefore set the administrative forward rate to a value that allows these gas-only resources to break even by recovering the costs associated with these contracts in expectation. If the rate was instead set such that a different type of technology with lower program participation costs would break even, this rate would likely be too low to incent gas-only resources to participate in the program, and would therefore be less effective in meeting the objective of increasing the region's inventoried energy and improving its winter energy security relative to the status quo.

Q: Is the forward rate expected to incent oil resources to maintain inventoried energy?

A: Yes. The forward rate that was developed to incent program participation from gas-only resources is expected to be sufficiently high to also incent oil resources to maintain the maximum quantity of inventoried energy that the program allows them to sell.

Q: Did the ISO or its consultant do any analysis to support this claim?

A: Yes. As part of his analysis on the forward rate, Dr. Schatzki evaluated an indicative forward rate that would instead be based on the minimum payment necessary to incent oil resources to maintain their maximum quantity of inventoried energy. His analysis found that such a forward rate would be significantly lower than the forward rate that is intended to incent program participation from gas-only resources.

Q: How did the ISO establish a forward rate that represents the minimum rate necessary to incent a gas-only resource to sign a gas contract and participate in the program?

A: To estimate this rate, the ISO contracted with Dr. Todd Schatzki of the Analysis Group. Dr. Schatzki has expertise in power system economics, the region's natural gas infrastructure, and economic modeling. To establish this forward rate, he developed a simulation model that used historical gas price data to estimate a fair market value gas contract between a gas-only generator and a storage terminal that holds liquefied natural gas.

Dr. Schatzki then estimated a generator's expected incremental revenues and costs associated with signing such a gas contract, and determined the outstanding contract costs that must be recovered through the interim program so that the generator 'breaks even' from signing this contract. This 'break even' payment was then converted into the forward rate for the interim program.

The methodology and assumptions used to establish this forward rate are described in significant detail in the memorandum authored by Dr. Schatzki and his colleague, Christopher Llop, that is included as an attachment to the testimony provided with this filing by Dr. Schatzki.

Q: Based on this analysis, what is the program's 'break even' forward rate?

A: The rate is calculated at $82.49 per MWh of inventoried energy sold forward.

Q: Why does the program set the forward rate now, when this rate will not be used until December 2023?

A: The first delivery period for the inventoried energy program runs from December 2023 through February 2024. This period falls within the Capacity Commitment Period that runs from June 1, 2023 through May 31, 2024, and the Forward Capacity Auction for that Capacity Commitment Period will be conducted in February of 2020. Setting the forward rate now, in advance of that 2020 Forward Capacity Auction, will help the program meet its primary design objectives of keeping the program simple and transparent. Furthermore, establishing this rate now may also help the program meet its objective of reducing the likelihood that resources that maintain inventoried energy that contributes to the region's winter energy security seek to retire.

Q: Please explain how setting the program's forward rate now will help make the program simple and transparent, and potentially reduce the likelihood that resources that maintain inventoried energy seek to retire.

A: Establishing the forward rate now, concurrent with other program components, will allow Market Participants to account for expected program revenues when developing offer and bid prices for the upcoming Forward Capacity Auctions to be run in 2020 and 2021 (the Forward Capacity Auction conducted in 2021 will be for the Capacity Commitment Period that includes the second year of the interim inventoried energy program). These forward auctions generally determine resource entry and exit decisions, and they are run more than three years in advance of the commitment period – a resource that sells capacity in the Forward Capacity Auction run in February 2020 is required to meet its capacity obligation during the Capacity Commitment Period that runs from June 2023 to May 2024.

By fixing the interim program's forward rate now, Market Participants will be able to forecast the program revenue that they expect to earn and incorporate this revenue into their competitive Forward Capacity Auction offer or de-list bid price for the relevant Capacity Commitment Period. This makes the program significantly more simple and transparent, because when developing their Forward Capacity Auction de-list bid prices, participants are not required to develop their own forecasts of the program's forward price based on their expectations of future market conditions.

Furthermore, to the extent that this increased revenue certainty reduces the risk assigned to expected future program revenues, it may allow a resource to more fully incorporate this revenue into its Forward Capacity Auction de-list bid price. Fully accounting for these revenues may reduce the likelihood that the resource exits the market and increase the region's inventoried energy.

Q: Would establishing the forward rate closer to the delivery period similarly allow the program to be simple and transparent, and to potentially reduce the likelihood of retirement for resources that provide inventoried energy?

A: No. While a rate that is established closer to the delivery period would have the benefit of updated data, it is unlikely to be known to the market until after resources are required to make irreversible decisions about whether to de-list a resource in the Forward Capacity Auction. As a result, resources that can maintain inventoried energy would have to develop their de-list bid prices based on their forecast of the forward rate. This reduces the program's simplicity and transparency relative to setting this rate before such bids are due.

Because program participants may assign more risk to unknown revenues, they may account for less revenue in their Forward Capacity Auction de-list bids. This would tend to increase the likelihood that the resource retires (relative to the approach as filed using a set forward rate), and would therefore reduce the program's ability to meet its objective of reducing the likelihood that such resources retire.

Q: Does the decision to establish the forward rate now represent an instance in which the ISO prioritized simplicity over sound market design principles?

A: Yes. As noted in Part III of this testimony, there is a tension between the design objectives and there may be instances where it is not possible to fully meet each. In this instance, the interim program prioritizes simplicity over sound market design principles in order to ensure that the interim program could be designed and understood by Market

Participants in the timeframe necessary to potentially impact capacity market bidding decisions and serve as a bridge to the longer-term market-based approach. Because establishing the forward rate closer to the delivery period is less effective in meeting this prioritized design objective, the ISO opted to instead establish the forward rate now.

C. Spot Rate

Q: What is the goal in setting the spot rate for the inventoried energy program?

A: The spot rate is calculated such that a resource would expect to earn similar total program revenues for selling the same quantity of inventoried energy via the forward or spot settlement. By ensuring that selling inventoried energy forward is not expected to produce *greater* revenues than selling it spot, the program will prevent 'money for nothing' schemes, where a participant can earn expected profits by selling inventoried energy forward, when it has no intention of actually maintaining inventoried energy for Inventoried Energy Days. By ensuring that selling forward is not expected to produce *lower* revenues than selling spot, it helps allow the forward settlement to be a viable mechanism by which participants can sell inventoried energy to potentially reduce their revenue uncertainty.

Q: How is the spot rate calculated to ensure that this property holds?

A: The calculation can be most easily explained using a simple example in which a resource sells 10 MWh of inventoried energy. First, consider the resource's revenue if it sells this inventoried energy forward. Assuming that it maintains this 10 MWh of inventoried energy for the measurement associated with each Inventoried Energy Day (that is, there are no deviations to consider), this resource will receive total program revenues of $824.90 ($82.49/MWh × 10 MWh in the forward settlement; $0 in the spot settlement).

The spot rate must then be determined such that the resource would expect to earn similar revenues if it instead sold 0 MWh forward, but nonetheless provided 10 MWh of inventoried energy for each Inventoried Energy Day. While the actual number of Inventoried Energy Days during the delivery period may vary year to year, as discussed in Part VI of this testimony, historical data indicates that approximately 10 Inventoried Energy Days per winter should be expected. If this expectation is realized, the spot rate should be calculated such that the resource would earn total program revenues of approximately $824.90 from selling a total of 100 MWh of inventoried energy via the spot component of the program (10 MWh/Inventoried Energy Day × 10 Inventoried Energy Days).

The spot rate is therefore established by dividing the targeted revenue amount of $824.90 by the amount of compensated inventoried energy (100 MWh). After rounding to the nearest cent, this yields a spot rate of $8.25 per MWh. If the resource sells 0 MWh forward, but provides 10 MWh of inventoried energy on each of 10 Inventoried Energy Days, it would therefore earn total program revenues of $825.00, which are nearly identical to those that it would receive if it had sold the 10 MWh forward (with no spot deviations), where this minor difference in revenues of $0.10 occurs because the spot rate is rounded to the nearest cent.

Q: Will the spot rate permit a participant to earn positive expected program revenues by selling the product forward and then failing to actually deliver the product on Inventoried Energy Days, as obligated?

A: No. The spot rate will prevent such 'money for nothing' scenarios, as can be shown with a simple example. Consider a resource that again sells 10 MWh of inventoried energy forward, but then does not actually maintain any inventoried energy for each of the ten Inventoried Energy Days that occur during the delivery period.

In such a case, the resource would be paid $824.90 (82.49/MWh × 10 MWh) in the forward settlement for the 10 MWh it sold forward. However, in the spot settlements, it would then be charged a total of $825.00 ($8.25/MWh × 10 MWh/Inventoried Energy Day × 10 Inventoried Energy Days) because it failed to meet its forward financial obligation associated with each Inventoried Energy Day. In aggregate, this resource would incur a program charge of $0.10 (due to the rounding of the spot rate), meaning it does not profit from selling inventoried energy forward that it does not intend to deliver.

Q: Could selling forward be more advantageous than selling spot if the total number of Inventoried Energy Days differed from expectations?

A: Yes. Generally speaking, if the total number of Inventoried Energy Days turns out to be less than ten (the approximate historical average), then program revenues are maximized by selling forward. This can be shown by comparing the revenues from selling 10 MWh of inventoried energy forward versus spot when there are only five Inventoried Energy Days. If the resource sells this inventoried energy forward, its total program revenues will be equal to $824.90 ($82.49/MWh × 10 MWh forward, $0 spot). If the resource does not sell inventoried energy forward and instead only sells it spot, it will receive lower program revenues of $412.50 ($0 forward, $8.25/MWh × 10 MWh/Inventoried Energy Day × 5 Inventoried Energy Days spot).

Q: Could only selling spot also be advantageous relative to selling forward if the total number of Inventoried Energy Days differed from expectations?

A: Yes. If the total number of Inventoried Energy Days turns out to be greater than ten (the approximate historical average), then program revenues are instead maximized by selling spot. This is shown by modifying the above example to instead have 15 Inventoried Energy Days. The forward sale of 10 MWh of inventoried energy will again yield $824.90 in program revenues. The spot sale of this inventoried energy would now yield program revenues of $1,237.50 ($0 forward, $8.25/MWh × 10 MWh/Inventoried Energy Day × 15 Inventoried Energy Days spot).

Q: Are there different risks associated with selling forward and spot?

A: Yes. For resources that expect to maintain a predictable amount of inventoried energy for each Inventoried Energy Day, there is likely to be more revenue certainty associated with selling inventoried energy forward because this provides relatively stable program revenue, whereas selling this inventoried energy spot will lead program revenues to be highly dependent on the number of Inventoried Energy Days, which is uncertain. This was shown in the earlier examples, where the resource selling forward earned the same program revenue whether there were 5 or 15 Inventoried Energy Days. If it instead sold spot, its program revenues varied with the number of Inventoried Energy Days.

However, there are also risks with selling forward, especially for resources that may not expect to maintain a predictable amount of inventoried energy for each Inventoried Energy Day. In particular, if a resource maintains significantly less inventoried energy than it sells forward, and it turns out to be a cold winter with more than 10 Inventoried Energy Days, the resource may incur significant spot charges. In extreme cases, it is even possible that these spot charges could exceed the resource's forward payment, meaning its net program revenues are negative. A resource that may not expect to maintain inventoried energy for each measurement can avoid this risk of net program charges by only selling inventoried energy spot.

Q: Are Market Participants free to choose how to manage this risk?

A: Yes. As a threshold matter, participation in both the forward and spot components of the program is entirely voluntary. Furthermore, Market Participants can choose how much of their inventoried energy to sell forward, where deviations between the quantity maintained and that sold forward are settled at the spot rate. As a result, a Market Participant could choose not to sell any inventoried energy forward to avoid the risk of incurring spot charges for failing to meet its forward financial obligation, and it will then be compensated at the spot rate for every MWh of inventoried energy that it maintains for each Inventoried Energy Day.

Alternatively, participants can choose to sell a portion of their potential inventoried energy forward, with the remainder being sold spot. This may reduce their risk if they do not expect to maintain their full inventoried energy quantity for each measurement, but also do not want to rely solely on the spot settlement (and the associated revenue uncertainty that comes with only being compensated if and when Inventoried Energy Days occur).

<u>VI. TRIGGER CONDITIONS</u>

Q: What is the role of the trigger conditions in the inventoried energy program?

A: As explained previously, one of the program's objectives is to improve winter energy security by increasing the quantity of inventoried energy that is available to be converted into electric energy during stressed winter conditions. The program seeks to satisfy this objective, in part, by incenting resources to take actions to manage their inventories so that they can be converted to electric energy, if necessary, during times of system stress. The trigger conditions are intended to identify periods where the system is more likely to be stressed, so that the program will provide strong incentives for Market Participants to take actions to maintain inventoried energy when it is needed most.

Q: In addition to identifying such periods, did any other principles guide the determination of the trigger conditions?

A: Yes, it is also important that the trigger conditions be based on simple, objective, and transparent conditions that can be forecast using historical data, and that they be independent of ISO procedures, participant actions, and general market conditions.

Q: Why is that important?

A: As with any settlement process, using trigger conditions that are simple, objective, and transparent will allow Market Participants to know when trigger conditions are in effect, and will also help them to project the likelihood of trigger conditions in future periods. In each case, the Market Participant can then use this information to manage its existing inventoried energy as appropriate. For example, if trigger conditions are currently occurring or the Market Participant expects that they will occur in future periods, the Market Participant may consider taking actions to maintain its existing inventoried energy or arrange for this inventory to be replenished, in order to increase its revenue from the program. Such actions will help ensure that the region has sufficient inventoried energy to meet energy demand during stressed winter conditions.

If the inventoried energy program is to reduce the likelihood that resources that contribute to the region's winter energy security pursue retirement, it is critical that these economic resources can forecast their expected program revenue and incorporate it into their capacity market bids. These bids must be submitted approximately four years before the program's delivery period, however, and it may be difficult to forecast the number of trigger conditions that far in advance. Basing the trigger conditions on criteria for which historical data is available and predictive of future outcomes will reduce this concern. For this historical data to be predictive going forward, it should not be based on broad market conditions which may constantly evolve, or on ISO or participant actions for which the past may not be a good predictor of the future. Criteria that avoid each of these concerns will allow participants to better develop expectations of future trigger conditions based on the observed historical data and use these expectations when participating in the Forward Capacity Auction.

Q: Given these considerations, what are the specific trigger conditions for the inventoried energy program?

A: The interim program is triggered for any calendar day in the months of December, January, or February for which the average of the high temperature and the low temperature on that day, as measured at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit. Any such day is defined as an "Inventoried Energy Day" under the program.

The trigger conditions rely on observed, rather than forecast, temperatures. As a result, whether a day was an Inventoried Energy Day will only be known definitively after the day's high and low temperatures have been determined. Consistent with this, program participants are required to report their inventoried energy to the ISO the morning after the conclusion of each Inventoried Energy Day. That reported inventory forms the basis for the participant's spot settlement.

Q: Why is the program limited to December, January, and February?

A: The program is intended to address concerns surrounding winter energy security. It is therefore appropriate that it be limited to the months in which this reliability concern is most pronounced because more of the natural gas available to the region through the interstate pipelines is being used for heating, rather than electricity generation. Thus the ISO will only evaluate trigger conditions in these months.

Q: Why is the trigger based on temperature?

A: A temperature-based metric is simple, transparent, and objective, and will allow Market Participants to evaluate whether a given day is likely to be an Inventoried Energy Day. Furthermore, participants can develop expectations about the likelihood that future days will be Inventoried Energy Days based on temperature forecasts, and manage their inventoried energy accordingly. Finally, the availability of historical temperature data allows Market Participants to develop expectations about the number of expected Inventoried Energy Days for the entire winter period. This historical data is not likely to produce estimates that are stale or outdated if market conditions or ISO procedures change, as the temperature is unlikely to change in a dramatic and unpredictable manner during the program's delivery periods as a result of actions taken by the ISO or its Market Participants.

Furthermore, a temperature-based metric will allow for Inventoried Energy Days to occur during winter periods where the system is more likely to be stressed. The New England system is generally most stressed on cold days when much of the region's interstate pipeline capacity is being used to deliver natural gas for heating, and less pipeline capacity is available for use by the region's gas-fired electric generators. Based on this observation, a temperature-based metric is likely to produce Inventoried Energy Days during stressed winter conditions.

Q: Why do the trigger conditions rely on observed, rather than forecast, temperatures?

A: The trigger conditions rely on observed, rather than forecast, temperatures because this allows the program to compensate resources for maintaining inventoried energy on days when it is actually cold, rather than on days where it is forecast to be cold ahead of time. While this may require participants to project the likelihood that a future day will be an Inventoried Energy Day, it will prevent instances where an inaccurate temperature forecast leads to an Inventoried Energy Day occurring on a mild winter day, or to the program not specifying an Inventoried Energy Day on a cold winter day where system conditions may be more stressed.

Q: Why is the temperature measured only at Bradley International Airport in Windsor Locks, Connecticut?

A: While it would be possible to calculate an average temperature that accounted for various locations within New England, doing so would add complexity to the program and may reduce Market Participants' ability to forecast Inventoried Energy Days because they would then depend on the weather in several locations. Furthermore, when evaluating different potential locations for temperature measurement, the ISO personnel responsible for monitoring the region's gas infrastructure and considering the gas available to electric generation in New England when committing resources have determined that the temperature at Bradley International Airport tends to be a good predictor of the interstate pipeline gas capacity available for electric generation, relative to weather conditions in other locations in New England. These observations led to the conclusion that using the temperature at Bradley International Airport would be appropriate for determining Inventoried Energy Days in New England.

Q: The temperature-based metric uses the average of the high and low temperatures. Is this a commonly used metric to model how weather affects energy demand?

A: Yes. The average of the high and low temperatures is often used to calculate the familiar heating degree day metric. Using a base of 65, as is common, a day where the average of the high and low temperatures is 17 degrees Fahrenheit will correspond to a heating degree day of 48 degrees (65 degrees minus 17 degrees).

Q: How did the ISO determine that an average temperature of 17 degrees Fahrenheit is the appropriate cutoff temperature for an Inventoried Energy Day?

A: The determination of this cutoff temperature was subjective. A higher cutoff temperature will produce more Inventoried Energy Days, some of which may not correspond with stressed system conditions. And a lower cutoff temperature will produce fewer Inventoried Energy Days, and may exclude some cold, stressed winter days. The program seeks to strike a balance where the cutoff temperature generally produces Inventoried Energy Days on cold, stressed winter days, while not producing Inventoried Energy Days on winter days when the system is not stressed.

The ISO used historical data to assess the expected number of Inventoried Energy Days for a winter at different temperature cutoffs. A cutoff temperature of 17 degrees in the applicable three-month periods from December 2008 through February 2018 would produce Inventoried Energy Days on the coldest 10 percent of winter days (approximately). These criteria produced an average of approximately 10 such days per winter over the same period. Such an outcome appears to capture the coldest winter days, when the system is likely to be stressed, without being so conservative as to include many days when system conditions are not stressed.

Q: Did you also evaluate historical data to determine if the days that would have been Inventoried Energy Days between December 2008 and February 2018 corresponded with days where system conditions were actually stressed?

A: Yes. The ISO evaluated the relationship between a trigger condition based on a cutoff temperature of 17 degrees and stressed system conditions during the months of December through February over that period, using day-ahead gas prices in New England as a proxy for stressed system conditions. Generally, this data suggests that (i) the trigger conditions would tend to produce Inventoried Energy Days on days with higher day-ahead gas prices, and (ii) the days that experienced the highest day-ahead gas prices (as compared to oil prices) would have been Inventoried Energy Days.

Q: Why did you use day-ahead gas prices, both in absolute terms and relative to oil prices, as an indicator of stressed system conditions during the months of December through February?

A: Generally, stressed system conditions during those winter months occur when the gas supply available for electricity generation is limited. In such cases, the limited supply of gas will be reflected in a higher daily gas price. Furthermore, the relationship of this daily gas price to the price of oil is important, as this relationship impacts the extent to which the region's oil units are dispatched to provide electric energy, which influences the region's total stock of inventoried energy. During the winter, stressed system conditions often occur on days where prices flip, such that the price of day-ahead gas in New England exceeds the price of oil and resources that burn oil are more likely to generate electricity relative to resources that use natural gas. This will tend to reduce the region's inventoried energy, and may therefore adversely impact its winter energy security.

When considering both absolute and relative gas prices, the ISO focused on day-ahead gas prices, rather than intraday gas prices, because the product is more heavily traded day ahead and the data is a more reliable representation of the actual prices at which gas was transacted.

Q: Is there data to support the claim that, with a 17 degree cutoff temperature, Inventoried Energy Days would historically have occurred on days with higher day-ahead gas prices?

A: Yes. During the ten December through February periods from December 2008 to February 2018, New England day-ahead gas prices, as determined at Algonquin Citygates, were 75 percent higher than their seasonal average on days that would have been Inventoried Energy Days using a 17 degree cutoff temperature. In the December 2017 through February 2018 period, 14 of the 15 days that would have been Inventoried Energy Days using a 17 degree cutoff had day-ahead gas prices above the seasonal average. These observations suggest that using a 17 degree cutoff will lead to Inventoried

Energy Days on days where day-ahead gas prices are higher, on average, than the seasonal average, indicating that system conditions are more likely to be stressed.

Q: Is there data to support the claim that, with a 17 degree cutoff temperature, the historical days with the highest day-ahead gas prices (as compared to oil prices) would generally have been Inventoried Energy Days?

A: Yes. In the ten December through February periods from December 2008 through February 2018, there were 51 days where the day-ahead gas price was at least $5.00 per MMBtu more than the price of oil. The program would have produced Inventoried Energy Days on 31 (61 percent) of these days, indicating that the program would have increased incentives for resources to maintain inventoried energy on most days where this condition occurred.

During these ten periods, there were four days on which the day-ahead gas price was at least $25.00 per MMBtu more than the price of oil, which suggests that conditions are more severely stressed. On all of these days, the program would have produced an Inventoried Energy Day.

Q: Do these trigger conditions apply to all days in the December through February period, including weekends and holidays?

A: Yes. Any day in December, January, or February could be an Inventoried Energy Day, whether it corresponds with a weekday, weekend, or holiday. This treatment reflects the fact that some of the most stressed winter days in recent history have occurred on weekends and holidays. For example, the extended cold spell that New England experienced during the winter of 2017-2018 lasted for nearly two weeks, and included elevated day-ahead gas prices on a holiday (New Year's Day) and a weekend (Saturday, January 6 and Sunday, January 7).

Q: Earlier, you noted that the trigger condition determination is daily. Did you also consider more granular trigger conditions?

A: Yes. The ISO also considered more granular trigger conditions, such as an hourly determination. Ultimately, the ISO concluded that hourly trigger conditions would add complexity to the design without corresponding benefit, undermining one of the main design objectives that I discussed earlier – keeping the program simple so that it could be designed before retirement bids are due for the Forward Capacity Auction to be held in February, 2020.

More specifically, an hourly trigger condition criterion could require that participants report their inventoried energy quantities to the ISO on an hourly basis, which may be overly burdensome given that the program is slated to only be in effect for two years, and that some participants may have to manually measure their inventoried energy.

Alternately, the program could require that participants report their inventoried energy on a daily basis, and impute hourly values using the participant's energy generation since its last reported value. However, such a design requires the ISO to develop a methodology to impute this value for every resource that participates in this program. The introduction of such a methodology would likely add significant complexity to the program design and implementation, especially if it considers that resources do not convert fuel to electric energy at a constant rate.

Because requiring hourly reporting and developing a methodology to impute hourly values based on daily reporting add significant complexity to the proposed interim program with little value, the ISO determined that such a change would move the program away from its design objectives.

VII. MAXIMUM DURATION

Q: Please explain the maximum duration parameter, and how it informs the amount of inventoried energy that a resource can sell forward.

A: The maximum duration caps the amount of inventoried energy that a resource can sell in the forward and spot settlements. For example, consider Resource A with a maximum potential output of 100 MW. With a maximum duration of 72 hours imposed in the program, the amount of inventoried energy that Resource A is permitted to sell forward and spot is capped at 7,200 MWh (100 MW × 72 hours).

Q: Is it therefore correct to infer that the maximum duration is a program parameter that is applied similarly to each resource, but it may lead different resources to have different 'cap' values?

A: Yes. If Resource B has a maximum potential output of 200 MW, and the same maximum duration of 72 hours is applied, the amount of inventoried energy that Resource B is permitted to sell is 14,400 MWh (200 MW × 72 hours). While application of the cap permits Resource B to sell twice the amount of inventoried energy that Resource A is permitted, in both cases the cap allows the resource to be paid for the maximum amount of inventoried energy that it could potentially convert to electric energy over a 72 hour period.

Q: Why does the program cap the amount of inventoried energy that a resource can sell forward or spot?

A: This cap reflects that inventoried energy may provide winter energy security in the short-term operational time frame. For example, if a resource has enough inventoried energy to run for 10 hours, its adding another MWh of inventoried energy may materially improve the region's winter energy security because this incremental MWh of inventoried energy may be converted to electric energy during stressed winter conditions. However, if the resource has enough inventoried energy to run for six months, its adding another MWh of inventoried energy is less likely to improve winter energy security.

Q: How does this cap affect a resource that can maintain less inventoried energy than implied by multiplying its maximum potential output by the maximum duration?

A: It is important to understand that 72 hours does not represent a minimum quantity that is required to participate in the program. Rather, it serves as a cap on the inventoried energy quantity for which a resource is compensated. Resources with less inventoried energy than the quantity implied by this maximum duration will be compensated for the quantity they can maintain. Return to Resource A from above. As previously indicated, with its 100 MW maximum potential output and the program's maximum duration of 72 hours, it would be permitted under the program's terms to sell 7,200 MWh.

But now assume that Resource A's on-site oil tank can only hold enough oil to produce 5,000 MWh of energy. In this case, Resource A's sale of inventoried energy forward would be limited to the 5,000 MWh of inventoried energy that it can maintain. The amount of inventoried energy that the resource could report for the spot settlement of an Inventoried Energy Day will be similarly limited. Generalizing, the maximum quantity of inventoried energy a resource can provide forward or spot is set at the lesser of (i) the product of its maximum potential output and the maximum duration, and (ii) the inventoried energy it can maintain.

Q: How did the ISO choose a 72 hour maximum duration?

A: The ISO has not been able to conduct quantitative analyses to measure the reliability benefits associated with various maximum duration quantities. As a result, it must establish a maximum duration value based on subjective criteria.

A larger maximum duration value will compensate participants for more inventoried energy, and may therefore lead the region to hold more inventoried energy, which may improve winter energy security. However, because a larger maximum duration value compensates resources for more inventoried energy, it will also tend to produce higher program costs and may compensate resources for increments of inventoried energy which provide less winter energy security benefit. A lower value will compensate participants for less inventoried energy, and may therefore lead the region to hold less inventoried energy which would produce less winter energy security. Because this lower value compensates for less inventoried energy, it will tend to produce lower program costs and may reduce the likelihood that increments of inventoried energy that provide winter energy security benefit are compensated.

The program sets the maximum duration at 72 hours as, in the ISO's view, this appears to limit the program's compensation to increments of inventoried energy that are most likely to improve the region's winter energy security. Furthermore, this duration is broadly consistent with the ISO's operational experience during the cold spell in the winter of 2017-2018. During this period, the ISO took action to conserve energy inventories by reducing the output of certain units (referred to as "posturing") for up to three consecutive days, thereby managing the region's inventoried energy in an effort to help maintain system reliability.

VIII. PROGRAM ELIGIBILITY

A. Technologies and Fuels Eligible to Participate in the Program

Q: How did the ISO determine what types of technologies and fuels will be eligible to sell inventoried energy under the interim program?

A: The ISO identified a set of three conditions that should be satisfied for a resource to provide inventoried energy. First, this inventory can be converted to electric energy at the ISO's direction. Second, the conversion of this inventoried energy to electric energy reduces the amount of electric energy the resource can produce in the future (before replenishment). And third, this inventoried energy can be measured by the participant, in MWh, and reported daily.

Q: What is the rationale behind the first condition, which requires that the inventory can be converted into electric energy at the ISO's direction?

A: The program seeks to buy inventoried energy that can be converted to electric energy at the ISO's direction during periods of system stress, if necessary, to provide winter energy security. It is therefore essential that this inventoried energy can be converted to electric energy as directed by the ISO during these periods of system stress.

Q: What is the rationale behind the second condition, which requires that the conversion of this inventoried energy reduces the amount of electric energy the resource can produce in the future (before replenishment)?

A: By definition, inventoried energy is stored at present and can be converted into electric energy at a later period. As discussed earlier, a key contributor to the region's winter energy security concerns is the potential lack of inventoried energy available to be converted to electric energy during extended cold spells. This program seeks to ameliorate this concern by directly compensating resources that maintain inventoried energy, rather than convert it to electricity and reduce the inventory, thereby ensuring its availability during cold weather periods.

Q: What is the rationale behind the third condition, which requires that the inventoried energy can be measured by the participant in MWh and reported daily?

A: As with any product for which Market Participants are compensated, they must be able to provide the ISO with settlement quality data that accurately reflects the quantity of the product delivered. Absent this requirement, Market Participants could be compensated at a level that was inconsistent with the quantity of inventoried energy that they maintained, which could lead consumers to pay for inventoried energy that was not actually available.

Q: Based on these three conditions, is an electric generator that can convert oil into electric energy eligible for compensation for its oil under the program?

A: Generally, yes, as such an electric generator is likely to satisfy each of the three conditions above. A generator that converts oil to electric energy can follow the ISO's dispatch instructions. Furthermore, when this resource burns oil to generate electric energy, it reduces the amount of oil in its tank, and therefore can produce less electric energy in future periods before replenishment. Finally, this oil can be measured in barrels, and that amount can be converted into an inventoried energy quantity (measured in MWh), based on the generator's physical characteristics, including its heat rate. Importantly, these three conditions are met by a generator that converts only oil into electric energy and also by a dual-fuel generator that can convert multiple fossil fuels to electric energy and that has dedicated oil. As a result, a dual-fuel generator with dedicated oil can be compensated for the inventoried energy associated with this oil under the program.

Q: Is an electric generator that converts coal into electric energy and stores its coal on-site eligible for compensation for this coal under the program?

A: Yes. Similar to an electric generator that converts oil to electric energy, a coal generator will generally satisfy each of the three conditions.

Q: Is an electric generator that converts nuclear fuel into electric energy eligible for compensation for this nuclear fuel under the program?

A: Yes. An electric generator that converts nuclear fuel into electric energy generally satisfies each of the three conditions identified. While nuclear generators do not typically have a wide range of output levels at which they can be dispatched, they do follow ISO dispatch instructions. Furthermore, while the rate at which generators using nuclear fuel replenish that fuel generally differs from generators using dedicated fossil fuels, the conversion of nuclear fuel to electric energy nonetheless reduces the amount of nuclear fuel on site that can be converted into electric energy at some future period.

Q: Could an electric generator that converts biomass or refuse coal into electric energy be compensated under the program?

A: Yes. A biomass or refuse generator that satisfies each of the three conditions set forth above can be credited with inventoried energy for the amount of material stored on site.

Q: Is a hydro generator that converts water into electric energy eligible for compensation for this water under the program?

A: Some hydro generators meet the three conditions identified earlier, and others do not. Generally, if the hydro generator has a pond or reservoir on site or upstream, and this resource can be dispatched by the ISO to convert this water into electric energy, and the amount of water available to be converted to electric energy can be measured by the participant and reported to the ISO, then the resource can be compensated for water that is stored in the pond or reservoir.

Q: Are there any limitations on upstream ponds or reservoirs?

A: Yes. For water in an upstream pond or reservoir to be counted as inventoried energy in this program, the Market Participant must have control over the decision to flow the water from the upstream pond or reservoir to the hydro generator. Additionally, the program limits the eligibility of water in upstream ponds or reservoirs to those with a transit time to the generator of no more than 12 hours.

Q: Why is the limit set at twelve hours?

A: Twelve hours provides roughly comparable treatment to fossil fuel generators that are eligible to sell inventoried energy in the program. Specifically, based on the current fleet in New England, the maximum cold start time among fossil fuel generators eligible to participate in the program is roughly twelve hours. This twelve-hour restriction therefore means that both fossil fuel and hydro generators with an upstream pond or reservoir can begin to convert their inventoried energy into electric energy in twelve hours or less.

Q: Can a pumped-storage resource be compensated for inventoried energy under this program?

A: Yes. Similar to eligible hydro resources, a pumped-storage resource can generally be credited with inventoried energy for water in its on-site reservoir that can be converted into electric energy at the ISO's direction.

Q: Can an Electric Storage Facility and storage systems coupled with wind or solar resources be compensated for inventoried energy under this program?

A: Yes. An Electric Storage Facility can generally be credited with inventoried energy for the electric charge that it holds that can be converted into electric energy at the ISO's direction. Similarly, a storage system coupled with a wind or solar resource may also be credited with inventoried energy for the electric charge that it holds.

Q: Can a Demand Response Resource be compensated for inventoried energy under this program?

A: It depends. If the Demand Response Resource meets the three conditions discussed above and the fuel it uses meets the eligibility and reporting requirements for that fuel type, then it can be compensated under the program. For example, if the Demand Response Resource is a behind-the-meter fossil fuel generator that can follow ISO dispatch instructions and has on-site fuel that can be measured, it can be compensated under the program.

Q: Can an External Resource that sells energy to New England using External Transactions be compensated for inventoried energy under this program?

A: No. Energy is sold into New England using External Transactions that are submitted by Market Participants. These transactions are financial contracts to sell energy from a participant in one control area to a participant in another and are scheduled by the ISO in coordination with the system operator for the neighboring Control Area to establish the inter-area power flow. Although External Transactions may indicate that they are backed by the output of a specific resource (rather than the system energy of the neighboring area), the ISO does not have the ability to directly control the output of any External Resource. Any inventoried energy held by an External Resource therefore cannot be converted to electric energy at the ISO's direction, meaning the first eligibility condition cannot be met.

Q: Can a solar or wind resource be compensated for inventoried energy under this program?

A: No. Such resources do not satisfy the second or third conditions identified above. Specifically, their production of electric energy in the present does not reduce their ability to generate electric energy in the future. Additionally, they do not have measurable inventory that would serve as a basis for compensation under the program.

Q: Are settlement-only resources eligible to participate in the program?

A: No. Such resources do not follow ISO dispatch instructions and therefore cannot convert inventoried energy into electric energy at the ISO's direction. Because this condition is not met, settlement-only resources are not eligible to participate in the inventoried energy program.

Q: Can a natural gas resource be compensated for inventoried energy under this program?

A: Yes. A natural gas resource can be compensated for inventoried energy under this program if it signs a contract for the firm delivery of gas that can be called on to produce electric energy at the ISO's direction. Such contracts generally satisfy the three conditions outlined above. This contract may be with one of the LNG facilities that serves the region, or it could instead be with a counterparty that does not source the gas at an LNG facility. To ensure that these contracts are likely to provide inventoried energy that improves the region's winter energy security, the program includes specific provisions that they must satisfy, as discussed below.

B. Provisions Regarding Contracts for Natural Gas

Q: Why does the program allow contracts for the firm delivery of gas to be eligible for compensation as inventoried energy?

A: As discussed in Part V.B, the program specifies a forward rate that aims to be sufficiently high to incent gas resources to sign contracts for the firm delivery of gas. Such contracts can be called during stressed winter conditions, and the availability of such gas for electric generation will represent a form of inventoried energy that improves the region's winter energy security.

Q: What conditions must a gas contract satisfy in order for it to be eligible for compensation as inventoried energy?

A: Such contracts differ from other types of inventoried energy, as they are financial in nature, rather than physical. As a result, the measurement of the gas is based on the terms of the contract, rather than the actual quantity of fuel that is stored in the tank, pile, or pond and directly available to the generator. To increase the likelihood that gas contracts eligible for inventoried energy compensation represent gas that can be converted to electric energy in a manner similar to other forms of inventoried energy, and that will help to improve region's winter energy security, the program requires that they meet two additional conditions. First, this contract must allow for firm delivery of the gas and must include no limitations on when natural gas can be called during a day. Second, the contract must not require that the Market Participant incur incremental costs to exercise the contract that could be greater than 250 percent of the delivery period's average forward price.

Q: What is the rationale behind this first condition, which requires that the contract provide for firm delivery of the gas and must include no limitations on when natural gas can be called during a day?

A: The region's winter energy security concerns are largely driven by the physical gas pipeline constraints that limit the delivery of natural gas into New England. Because much of the firm pipeline capacity into New England serves residential and commercial heating demand, these constraints generally impact the region most significantly on cold winter days.

Gas contracts that include firm delivery reduce such winter energy concerns by ensuring that gas is available for electric generation when the contract is called, including on cold winter days when system conditions are most likely to be stressed. This requirement means that, like other fuel types, this inventory can be converted to electric energy at the ISO's direction. Conversely, contracts that do not include firm delivery are most likely to be undeliverable on precisely the winter days when system conditions are stressed and this energy is needed most. For this reason, the program requires that any gas contract allow for firm delivery in order to be counted as inventoried energy.

As to the requirement that the contract include no limitations on when natural gas can be called during a day, this ensures that, like other fuel types, this inventory can be converted to electric energy at the ISO's direction. Contractually-provided natural gas inventory may not improve the region's winter energy security if limitations on when it could be called prevented its use on cold days where system conditions are stressed and this energy is needed most.

Q: What is the rationale behind the second condition, which states that the contract must not require the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the delivery period's average forward price?

A: As discussed earlier, the program aims to increase the deliverable gas for electric generation on cold winter days where system conditions are more likely to be stressed. This condition seeks to address potential instances where a gas-fired generator signs a contract with very significant incremental costs of buying the gas. Under such contract terms, the contract counterparty may not have a strong financial incentive to take the necessary steps to ensure that the gas is actually available and deliverable if called because the likelihood that the gas is called is low. In such cases, the contracted gas may not actually improve the region's winter energy security, as the gas may not be available during the precise times when it is most likely to be called, where system conditions are stressed and the availability of additional gas for electric generation would potentially improve winter energy security. This condition therefore seeks to limit inventoried energy compensation for gas contracts to the set of contracts where the contract counterparty has a strong incentive to ensure that the gas is available and deliverable to the generator because the contract's incremental costs suggest it may be called.

Q: How will this 250 percent threshold affect contracts for which the incremental cost of the gas is uncertain at the time the contract is executed, but may ultimately exceed this value?

A: Some contracts may have incremental costs that are indexed to market prices or conditions that are not finalized at the time the contract is executed. In such cases, where a contract could have incremental costs above this 250 percent threshold value, its gas would not be eligible to participate in the inventoried energy program. This requirement will help to ensure that the program only compensates participants for gas that cannot have incremental costs above this threshold value, and may therefore be more likely to be available during stressed system conditions.

Q: Why does the program use 250 percent of the seasonal forward price as its threshold?

A: The ISO assessed daily gas price data over the winter periods from December 2008 through February 2018 to determine the frequency with which the daily price exceeded the seasonal average by various thresholds, and found that on approximately 98 percent of days, the daily price was less than or equal to 250 percent of the seasonal value. This indicates that a buyer would be expected to use a contract with an option to buy gas above this 250 percent threshold price on less than 2 percent of winter days.

As the likelihood of purchasing gas associated with such a contract declines, the contract seller’s financial incentive to ensure that the gas is available and deliverable also decreases. The 250 percent threshold therefore seeks to exclude contracts that may be less likely to actually increase the region's winter energy security because this financial incentive is weakest, as contracts with incremental costs above this threshold would be expected to be used on less than 2 percent of winter days.

Q: How is this threshold calculated?

A: The threshold is calculated as 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period. This framework allows the contract parties to know the threshold price when entering into the contract, and thereby prevents scenarios where a Market Participant executes a contract with the expectation that it will be eligible to sell inventoried energy, but gas price changes after the contract is executed prevent the contract from being eligible.

By setting the latest date at which this threshold is determined to the first business day in October, the program uses a seasonal average across all three delivery period months even in cases where the contract is executed during the delivery period and a forward price for each month is no longer available. This October evaluation date will provide a transparent threshold price for contracts executed during the delivery period that is comparable to the value assigned to contracts executed at an earlier date, as it still reflects a seasonal forward average gas price.

Q: Are there any additional limitations on how gas contracts can participate in this program?

A: Yes. There is a cap on the total amount of inventoried energy that can be compensated under the program from gas contracts associated with LNG facilities that serve New England. Specifically, the quantity of inventoried energy associated with such contracts that can be compensated under the program is capped at 560,000 MWh.

Q: Why does the program include such a cap?

A: The amount of gas from LNG facilities that serve New England that can be delivered to electric generators in the region may be limited for several reasons, including the modest number of these gas facilities. The program's cap on the total inventoried energy associated with such gas injections reflects this physical limitation, and therefore reduces the possibility that more inventoried energy associated with these contracts is sold than can reasonably be expected to be deliverable during stressed winter conditions.

In recent history, the maximum daily quantity of gas scheduled from these facilities to the region's interstate pipelines during the winter months was approximately 1.4 Bcf. This quantity excludes gas scheduled from the Everett terminal to the Mystic generating units and to National Grid's local distribution company in Boston that does not flow through the region's interstate pipelines.

To calculate the program's cap in MWh, this gas quantity (in Bcf) is converted into an inventoried energy quantity. This calculation assumes that this maximum daily observed amount of scheduled gas (1.4 Bcf) is available for electric generation on each of the three days that correspond with the 72 hour maximum duration. This total gas quantity therefore becomes 4.2 Bcf (1.4 Bcf/day × 3 days). Assuming that this gas is converted to electricity at an average heat rate of 7.5 MMBtu per MWh, this produces a total of 560,000 MWh of energy (4.2 Bcf × 1,000,000 MMBtu/Bcf / 7.5 MMBtu/MWh).

Q: How does the program enforce this cap?

A: The program uses prorating rules to limit the total quantity of inventoried energy associated with contracts for liquefied natural gas that is compensated via both the forward and spot settlements. In the forward settlement, these prorating rules are relatively simple. If more than 560,000 MWh of inventoried energy associated with LNG-based gas contracts is offered forward, the program reduces each Market Participant's total inventoried energy sold forward associated with such contracts proportionally so that the total quantity associated with such contracts is equal to 560,000 MWh. This approach provides equitable treatment to all Market Participants that seek to sell inventoried energy associated with LNG-based gas contracts forward.

This forward prorating process is most easily demonstrated with a simple example. Imagine that the total quantity of inventoried energy associated with the LNG-based gas contracts offered forward from all Market Participants is 640,000 MWh. In this example, each Market Participant would be permitted to sell forward 87.5 percent (560,000 MWh / 640,000 MWh) of the inventoried energy it offers forward that is associated with LNG-based gas contracts to ensure that the total quantity sold forward does not exceed the cap quantity of 560,000 MWh.

There is also a prorating process associated with the spot settlement to ensure that the total quantity of inventoried energy credited in the spot settlement does not exceed 560,000 MWh. A Market Participant that sold inventoried energy associated with LNG-based gas contracts forward will be credited for the entire spot quantity it maintains during the Inventoried Energy Day, up to the amount of LNG-based inventoried energy it was permitted to sell forward, without any further prorating in the spot settlement. Because of prorating in the forward settlement, it is not possible for this portion of the spot quantity of LNG-based inventoried energy (from all Market Participants) to exceed 560,000 MWh. However, it is possible that after also accounting for inventoried energy associated with such contracts that is *not* sold forward, but is maintained spot, the quantity of LNG-based inventoried energy maintained spot could exceed 560,000 MWh. In such cases, the program prorates the LNG-based inventoried energy that is only delivered spot (meaning it is in excess of the Market Participant's forward position) to ensure that the total quantity of LNG-based inventoried energy that is credited in the spot settlement, including that associated with forward positions, does not exceed 560,000 MWh.

For example, imagine that on an Inventoried Energy Day, the total quantity of LNG-based inventoried energy is equal to 600,000 MWh, where 400,000 MWh of this quantity corresponds with LNG-based inventoried energy that has a forward position, and the remaining 200,000 MWh represents LNG-based inventoried energy for which the Market Participant did not have a forward position. In this case, the 400,000 MWh that correspond with forward positions would not be prorated in the spot settlement, and the remaining 200,000 MWh would be prorated to 80 percent ((560,000 MWh – 400,000 MWh) / 200,000 MWh) of its quantity maintained. This would lead to a total of 560,000 MWh of LNG-based inventoried energy being credited during the Inventoried Energy Day (the 400,000 MWh that was sold forward and not prorated, plus 160,000 MWh that was not sold forward but delivered spot and prorated).

Q: Why does the spot settlement not prorate LNG-based inventoried energy sold forward, whereas it does prorate such inventoried energy that is not sold forward but maintained on the Inventoried Energy Day?

A: This treatment seeks to reduce the risk for Market Participants signing LNG-based gas contracts to sell inventoried energy forward. Under these prorating rules, if a Market Participant maintains the full quantity of LNG-based inventoried energy sold forward during each Inventoried Energy Day, it will not face charges in the spot settlement for underperformance. This means that the Market Participant can generally control its performance risk in the spot settlement if it sells inventoried energy forward.

If the rules instead prorated all LNG-based inventoried energy in the spot settlement, this property would no longer hold and the Market Participant's spot LNG-based inventoried energy quantity may be reduced below the quantity that it sold forward, thereby producing a negative deviation, and hence a spot charge. The Market Participant would not be able to control this risk since it would be entirely dependent on the aggregate quantity of LNG-based inventoried energy that was maintained for Inventoried Energy Days by all Market Participants. As a result, prorating rules in the spot settlement that reduce the inventoried energy quantities associated with forward sales are likely to increase the risks of participating in the program, and may therefore reduce the likelihood that such LNG-based gas contracts are executed. Based on this concern, the ISO concluded that the prorating rules in the spot settlement should not be applied to LNG-based inventoried energy sold forward.

Q: Does this cap apply to any inventoried energy that is attributed to the Mystic generating units?

A: No. As noted above, the maximum daily observed quantity of gas scheduled from LNG facilities serving the region did not include vaporized LNG that was delivered to the Mystic generating units, as the gas used by these units generally does not limit the flow of gas from the region's LNG facilities to the region’s interstate pipelines. Because the calculation of the cap quantity does not include vaporized gas delivered to the Mystic generating units, any inventoried energy that is attributed to these units (where such inventoried energy is only eligible to participate in the program if these resources are not operating under a cost-of-service agreement, as discussed below) would not be considered for purposes of calculating the total quantity of LNG-based inventoried energy and, correspondingly, are not subject to the forward or spot prorating associated with this cap quantity.

C. Other Issues Related to Program Eligibility

Q: Can resources that were retained for reliability by the ISO and are being compensated via a cost-of-service agreement participate in this program?

A: No. The program seeks to reduce the likelihood that a resource that provides winter energy security seeks to retire, and also aims to incent resources to take actions before and during the delivery period to improve the region's winter energy security. Resources that have a cost-of-service agreement have already indicated an intent to retire. And this program is unlikely to impact their decisions regarding inventoried energy as they do not participate in the region's competitive markets in a manner similar to other resources. Finally, it appears unlikely that such resources would have an incentive to participate in the inventoried energy program, as any program revenues are likely to offset their cost-of-service payments. Based on these observations, the ISO is excluding such resources from participating in the program.

Q: Is a resource required to have a Capacity Supply Obligation to participate in the inventoried energy program?

A: No. The program seeks to provide similar compensation for similar service. The service provided here is inventoried energy that can be converted into electric energy at the ISO's direction. This service, as defined by the three conditions described above, can be provided by resources that have a Capacity Supply Obligation as well as those that do not. The inventoried energy program therefore does not require such an obligation to be eligible to participate.

IX. PROGRAM COSTS AND IMPACTS

A. Indicative Program Costs

Q: As part of its analysis, did the ISO evaluate the estimated annual costs of the inventoried energy program?

A: The ISO contracted with Dr. Schatzki of the Analysis Group to provide a representative estimate of the program's total annual costs. This estimate is discussed in more detail in the testimony provided by Dr. Schatzki with this filing.

Q: What assumptions were used to calculate this representative estimate of the program's total annual costs?

A: This representative estimate assumes that: (i) all eligible non-gas resources sell their maximum quantity of inventoried energy forward and maintain this amount for each Inventoried Energy Day, and (ii) the total quantity of inventoried energy provided by gas resources is equal to 560,000 MWh, the cap quantity governing LNG-based contracts (as discussed in more detail in Part VIII.B).

Q: Under these assumptions, what are the estimated annual program costs?

A: Under these assumptions, Dr. Schatzki estimates representative program costs of $148 million per year. This corresponds to roughly 1.8 million MWh of inventoried energy sold forward and maintained for each Inventoried Energy Day. Because this estimate assumes that the quantity of inventoried energy associated with gas contracts is equal to the LNG-based inventoried energy cap quantity, it can be considered the representative 'upper bound' estimate.

Q: How would this annual cost estimate change if it instead assumed that the program did not incent resources to sign gas contracts?

A: If the program does not incent resources to sign gas contracts, the total quantity of inventoried energy would decrease by 560,000 MWh (the cap amount assumed in the 'upper bound' scenario), and this would produce program costs of approximately $102 million per year, where 1.2 million MWh of inventoried energy are sold. Because this estimate assumes no gas participation, it can be considered the representative 'lower bound' estimate.

Q: Is it possible that the actual annual program costs could be less than the representative lower bound estimate or greater than the representative upper bound estimate?

A: Yes. These cost estimates make several assumptions about program participation, resource performance, and winter severity that may not hold, which could lead to higher or lower annual program costs. First, these estimates assume that all non-gas resources choose to participate in the program. If some of these resources choose not to participate, program costs may be lower. On the other hand, if additional gas resources sign contracts that are not LNG-based, new resources enter the region, or existing resources make investments that allow them to hold more inventoried energy, program costs may be higher than estimated.

Second, these estimates assume that the total quantity of inventoried energy maintained during each Inventoried Energy Day is equal to that sold forward. If this assumption is incorrect and resources participate in the program and sell their inventoried energy forward, but do not maintain this forward amount for each Inventoried Energy Day, this will result in spot charges to these under-performing resources which will reduce the program's total cost (because these charges will result in a credit to consumers in the form of reduced program charges).

Third, these estimates assume that all Market Participants choose to sell their inventoried energy forward. However, to the extent that participants instead choose to sell inventoried energy spot, program costs will tend to increase with the number of Inventoried Energy Days because payments for inventoried energy will be made to participants selling spot for each Inventoried Energy Day. Specifically, program costs will tend to be higher than those estimated if participants opt to sell inventoried energy spot rather than forward, and the number of Inventoried Energy Days during the delivery period is greater than ten (recall, as discussed in Part V.C, that a resource that sells spot earns higher program revenue than a resource that sells forward if the number of Inventoried Energy Days exceeds its historical average of ten). Similarly, if the number of Inventoried Energy Days during the delivery period is less than ten, this will produce lower total program costs.

Q: How are program costs allocated?

A: Consistent with how costs were allocated under the earlier winter reliability programs and with the retention of resources for fuel security, program costs will be allocated on a regional basis to Real-Time Load Obligation. The total costs associated with the forward sale of inventoried energy will be evenly distributed across each day in the December through February delivery period. The spot settlement could result in a net charge to load if the total inventoried energy maintained for the Inventoried Energy Day exceeds the quantity sold forward, or a net credit to load if the total inventoried energy maintained for the Inventoried Energy Day falls below the quantity sold forward. In either case, this charge or credit is assigned to Real-Time Load Obligation on the Inventoried Energy Day.

Q: In addition to these direct program costs, are there also likely to be indirect effects of the program on other ISO wholesale markets?

A: Yes. Consistent with the program's second design objective, it may reduce the likelihood that a resource that maintains inventoried energy that contributes to the region's winter energy security seeks to retire. Mechanically, this objective is achieved by providing program revenues that allow such resources to reduce their de-list bid prices in the Forward Capacity Auction, thereby increasing the likelihood that they are awarded a Capacity Supply Obligation. Furthermore, the program introduces a new opportunity cost component to energy market offer prices during the program's delivery periods. How this opportunity cost is determined, and its potential impact on system dispatch, resource revenues, and the region's winter energy security is discussed in more detail below.

B. Interactions Between the Inventoried Energy Program and the Energy Market

Q: How would the program potentially impact bidding behavior and clearing prices in the energy market?

A: In order to achieve its second objective, the program seeks to affect how resources with inventoried energy manage that inventory to improve the region's winter energy security. More specifically, the ISO would expect resources to take actions to maintain or replenish their inventory in anticipation of upcoming Inventoried Energy Days. In order to maintain their existing inventory, resources may include an opportunity cost in their energy market offers to reflect that converting inventoried energy into electric energy at present may reduce the quantity of inventoried energy that is credited under this program for upcoming Inventoried Energy Days, and that this reduction may result in lower program revenues. This opportunity cost should therefore be calculated to ensure that the energy market payment that they would receive for converting this inventoried energy into electric energy at present is sufficiently high that it offsets any expected reduction in inventoried energy revenues that would occur.

Q: Can you provide a simple example of how this opportunity cost may be calculated?

A: Yes. Consider the simple case where Resource A has marginal costs of producing electric energy of $20 per MWh and no opportunity costs associated with producing energy other than those associated with the inventoried energy program. Resource A has a tank that holds a maximum of 48 hours of oil that it can convert to electric energy. The participant controlling Resource A sees that the temperature forecast for tomorrow is very cold, and expects it to be an Inventoried Energy Day. After tomorrow, the weather is expected to be mild, and no further Inventoried Energy Days are expected until Resource A's scheduled replenishment of oil will arrive and its tank is refilled.

Under these conditions, if Resource A converts oil to electric energy today, it will reduce the amount of inventoried energy that it has for the expected Inventoried Energy Day tomorrow. More specifically, for each MWh of electric energy it produces, it will reduce its inventoried energy by 1 MWh. This will result in a reduction in its spot settlement for this Inventoried Energy Day of \$8.25 (\$8.25/MWh × 1 MWh). As a result, Resource A has an opportunity cost of \$8.25 per MWh for each MWh of electric energy produced today. It should therefore increase its energy market offer price by \$8.25 per MWh above its marginal costs of \$20 per MWh to reflect this opportunity cost in its energy market offer price. By offering into the energy market at a price of \$28.25 per MWh, Resource A will ensure that if it generates electricity today and therefore receives a reduced inventoried energy payment for tomorrow, it is not made worse off because it recovers this lost revenue via a higher energy market payment.

Q: Can you illustrate why, by including its opportunity cost in its energy market offer price, Resource A is not made worse off if its offer is accepted and it converts inventoried energy to electric energy?

A: Yes. This can be shown by comparing Resource A's net revenues under the scenario where its \$28.25 per MWh offer is not accepted (meaning it does not generate electric energy, but maintains its full quantity of inventoried energy), to that where its offer is accepted and it therefore has less inventoried energy for the Inventoried Energy Day. For simplicity, this example assumes that Resource A has a maximum potential output of 100 MW and offers this full amount into the energy market at $28.25 per MWh. Because it starts with 48 hours of oil in the tank, this corresponds to 4,800 MWh of inventoried energy. For simplicity, this example assumes that the resource does not sell inventoried energy forward, meaning any inventoried energy maintained during the Inventoried Energy Day is paid the spot rate.

In the first scenario, where its energy market offer is not accepted, Resource A earns no energy market revenues. Because Resource A does not convert any of its inventoried energy into electric energy, it maintains the full 4,800 MWh of inventoried energy. This leads to spot compensation for the Inventoried Energy Day of $39,600 ($8.25/MWh × 4,800 MWh). Because it incurs no costs, Resource A's total net revenues between the energy market and inventoried energy program are $39,600.

In the second scenario, Resource A's energy market offer is accepted and it produces 2,400 MWh of energy (generating 100 MW for the entire 24 hours). This example assumes that it is the marginal resource in the energy market, and sets the energy price at its offer of $28.25 per MWh for the entire time it operates. Over the course of the day, the resource earns total energy market revenues of $67,800 ($28.25/MWh × 2,400 MWh). However, it also incurs costs to operate of $48,000 ($20/MWh × 2,400 MWh). It therefore earns net revenues in the energy market of $19,800. In order to produce this electric energy, it reduces its quantity of inventoried energy. It will maintain 2,400 MWh of inventoried energy for the Inventoried Energy Day (4,800 MWh – 2,400 MWh). This provides spot compensation for the Inventoried Energy Day of $19,800 ($8.25/MWh × 2,400 MWh). Summing the net energy market revenues with inventoried energy program revenues again yields total net revenues of $39,600 ($19,800 + $19,800).

Because its energy market offer includes the opportunity cost associated with converting inventoried energy into electric energy, Resource A is no worse off if its energy market offer is accepted and its inventoried energy is reduced. While these total net revenues are equal in the scenarios outlined above, if Resource A's energy market offer is accepted and the energy price it is paid exceeds its offer price (meaning it is no longer the marginal resource), it will earn greater net revenues by generating and reducing its inventoried energy than if its offer was not accepted.

Q: Would the revenue equivalence illustrated above hold more generally?

A: Yes. If Resource A fully accounts for the opportunity costs in its energy market offer price and is the marginal resource that sets the energy price, its net revenues from the energy market and inventoried energy program will be equivalent to those that it would receive if it did not produce energy. Similarly, if its energy market offer is accepted and the energy price exceeds its offer price (meaning its offer is inframarginal), it will earn greater net revenues by producing energy than if it did not produce energy and only earned revenues through the inventoried energy program.

These outcomes hold not only for cases where Resource A sells all of its inventoried energy spot, but also in instances where it sells all or a portion of its inventoried energy forward. The reason is that, independent of whether the participant sold inventoried energy forward, the difference in inventoried energy revenues between scenarios is equal to the product of the spot rate and the difference in the quantity of inventoried energy maintained.

Q: How would the opportunity cost corresponding with converting inventoried energy into electric energy differ if Resource A instead expected two Inventoried Energy Days before replenishment?

A: If Resource A expects two Inventoried Energy Days before replenishment, the reduction in inventoried energy revenues associated with each MWh of electric energy produced today would be equal to $16.50 ($8.25/MWh × 1 MWh/Inventoried Energy Day × 2 Inventoried Energy Days). The energy market opportunity cost if Resource A expects two Inventoried Energy Days before replenishment therefore doubles from the earlier example to $16.50 per MWh.

More generally, Resource A's opportunity cost will be proportional to the expected number of Inventoried Energy Days before replenishment. If it does not expect to replenish its inventoried energy before the end of the delivery period, then this opportunity cost should reflect the expected number of Inventoried Energy Days remaining during the delivery period.

Q: How would this opportunity cost change if the resource's oil tank had more than 72 hours of oil in it?

A: For a resource with more than 72 hours of inventory (the most that can be credited for any individual Inventoried Energy Day), the opportunity cost will generally decrease. For example, consider Resource B, which has a larger tank than Resource A and a sufficient quantity of oil to run for several days without replenishment and still have more than 72 hours of oil remaining in the tank. Assume that Resource B expects tomorrow to be an Inventoried Energy Day, and that it has a scheduled replenishment before any subsequent Inventoried Energy Days are anticipated. In this example, Resource B has no opportunity costs associated with converting its oil into electric energy today because doing so does not reduce its inventoried energy revenues for the Inventoried Energy Day tomorrow. Whether it burns oil to generate electricity today or not, it will maintain sufficient oil in the tank to receive the maximum inventoried energy spot settlement for the Inventoried Energy Day.

Q: Does such a framework benefit resources that have less inventoried energy, as they are likely to have higher opportunity costs than those with more than 72 hours of inventoried energy?

A: No. Consider Resources A and B from above, and assume that these two resources have similar marginal costs to producing electric energy. If Resource A includes an opportunity cost in its energy market offer to reflect the expected reduction in inventoried energy revenues if it converts oil to electric energy, while Resource B does not, this will lead Resource A's energy market offer price to be higher than Resource B's.

Resource B will tend to earn higher inventoried energy revenues because it always maintains the maximum quantity permitted by the program, whereas Resource A does not. Furthermore, because it does not include an opportunity cost in its energy market offer price, Resource B will tend to be dispatched more frequently, thereby earning greater energy market revenues. As a result, Resource B's ability to generate electric energy while maintaining the maximum allowable quantity of inventoried energy represents an advantage that allows it to earn greater energy market revenues and greater program revenues.

This example highlights that the resources that benefit most from this program are those that can generate electric energy while also maintaining a significant quantity of inventoried energy. This is an appropriate outcome as such resources can provide electric energy (and be compensated for this energy at the energy market clearing price) and also maintain a significant quantity of inventoried energy that contributes to the region's winter energy security.

Q: What types of resources will tend to have the lowest opportunity costs associated with inventoried energy? The highest opportunity costs?

A: Resources with very large amounts of inventoried energy, such as Resource B in the above examples, are unlikely to have significant opportunity costs because the conversion of their inventoried energy to electric energy does not reduce their remaining inventoried energy below 72 hours. Such resources are more likely to be dispatched in the energy market as they may displace other resources for which the inventoried energy program introduces an opportunity cost. Furthermore, when they are dispatched, they may expect to receive higher energy market revenues if the inclusion of opportunity costs in other resources' energy market offers increases the clearing price.

Resources that do not use inventoried energy to produce electric energy (that is, resources not eligible for compensation under the program) will have no opportunity cost, as their production of electric energy today does not impact their program revenues in the future. Like resources with large inventories, however, these resources may be more likely to be dispatched and receive higher energy market payments if other resources include opportunity costs in their energy market offers. This additional revenue associated with higher energy market prices will generally reflect that these resources that do not use inventoried energy may still help the region maintain inventoried energy when they displace resources that otherwise would convert inventoried energy into electric energy. However, unlike resources with large inventories, these resources will not also be directly compensated through the program, as they do not maintain inventoried energy.

Resources with limited inventories, such as Resource A in the examples above, will generally have higher opportunity costs associated with their energy market offer prices, and may therefore be less likely to have their offers accepted. These opportunity costs will depend on the number of expected Inventoried Energy Days before replenishment. As a result, this opportunity cost will generally increase as the time until the resource's next replenishment gets longer, and it will also tend to increase if the forecast weather conditions in the near-term (that is, before this replenishment) suggest a higher number of Inventoried Energy Days.

Q: What actions can resources take to reduce their opportunity costs and therefore increase the likelihood of earning both energy market revenues and compensation for inventoried energy?

A: There are several actions resources can take to reduce their opportunity costs and increase the likelihood that they earn energy market revenues while also being compensated for inventoried energy (in other words, so they can be more like Resource B in the above examples, rather than Resource A). First, they can make arrangements to ensure that they start the delivery period with a significant amount of inventoried energy. For resources that can carry more than 72 hours of inventory, this will allow them to generate more MWh of electric energy before their inventoried energy falls below the 72 hour maximum duration where their inventoried energy revenues are reduced.

Second, they can increase their ability to replenish their inventoried energy during the delivery period. Generally, such actions will reduce the number of expected future Inventoried Energy Days before their next replenishment, and will therefore decrease their opportunity cost of converting inventoried energy into electric energy before this replenishment occurs. The program most strongly incents replenishment when weather conditions in the near future are expected to be colder because opportunity costs and energy market prices are therefore likely to be high and the number of Inventoried Energy Days for which inventory will be measured and spot compensation will occur are also expected to be high. Market Participants may therefore choose to pursue replenishment arrangements that account for evolving weather conditions so that they can replenish when such conditions are expected.

Third, resources that can produce electric energy from both inventoried energy and non-inventoried energy, such as dual-fuel resources that can buy gas from the pipeline or use oil stored on site, are more likely to participate in the energy market using the non-inventoried fuel. These resources would still be expected to offer into the energy market based on the fuel that is lower cost. An offer based on the non-inventoried energy would have no opportunity cost associated with the inventoried energy program, whereas an offer based on the inventoried energy would. The opportunity cost associated with the inventoried energy will therefore increase the likelihood that the offer based on non-inventoried energy is lower cost, especially during periods where cold weather conditions are expected or the resource cannot replenish its inventoried energy in the near future.

Each of these actions increases the quantity of inventoried energy that is available to the region and will therefore help to improve its winter energy security.

Q: Will the inclusion of these opportunity costs in energy market offers change how the system is dispatched?

A: The inclusion of opportunity costs introduced by the inventoried energy program may change the order in which generators are called to meet demand. Resources with larger opportunity costs will increase their energy market offer prices, and these higher offer prices will make them less likely to clear. In their place, resources with limited or no opportunity costs are likely to be dispatched. Additionally, resources that can use either inventoried energy or non-inventoried energy to produce electric energy are more likely to use non-inventoried energy, as doing so does not potentially reduce their inventoried energy revenues. Relative to the status quo, this change in the supply stack will tend to decrease the likelihood that resources that have limited inventoried energy are dispatched using this fuel, thereby increasing the amount of inventoried energy available to the region and improving its winter energy security.

Furthermore, the magnitude of this impact is not fixed, and instead responds to the expected likelihood of future Inventory Energy Days. Specifically, the size of the opportunity costs introduced by the inventoried energy program generally increases during periods when cold winter conditions are expected, and decreases when milder weather conditions are forecast. As a result, the changes to dispatch to maintain the region's inventoried energy are expected to be most significant precisely when stressed system conditions appear more probable and this inventoried energy is likely to provide the most reliability benefit.

X. PROGRAM PARTICIPATION AND REPORTING

A. Information Required to Participate in the Inventoried Energy Program

Q: What information must Market Participants provide the ISO to participate in the program?

A: To participate in the program, certain information must first be submitted to and approved by the ISO. Market Participants must list the assets that will participate in the program and provide some information about each, including the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site or otherwise credited under the program; and a list of other assets that share the fuel inventory. Furthermore, the Market Participant must explain how the fuel associated with each of the listed assets will be measured for each Inventoried Energy Day when it occurs (such as barrels of oil, elevation or gallons of water in a pond, or contracts for the firm delivery of natural gas), and how that fuel will be converted into a MWh value for purposes of settlement.

For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas, meeting the requirements described above in Part VIII.B above, and specifying the relevant contract terms, such as the parties, term, price, volume, and delivery point.

In this submission, the Market Participant must also indicate whether it is electing to participate in the forward component of the program (and hence also the spot component), or only in the spot component. If electing to participate forward, the Market Participant must indicate total MWh value for which the Market Participant elects to be compensated at the forward rate. This forward election MWh value must be less than or equal to the combined MWh output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site or otherwise credited by the program (such as in upstream ponds for hydro resources or pursuant to a contract for natural gas). The Market Participant must also indicate what portion of the forward elected amount, if any, is associated with an LNG-based contract. This information will enable the ISO to prorate such contracts if necessary, as discussed in Part VIII.B above.

For Market Participants that wish to sell inventoried energy forward, this information must be provided to the ISO no later than the October 1 preceding the delivery period. This will allow the ISO with time to apply its review and approval process to the information submitted before the delivery period begins on December 1. The ISO will review each Market Participant's submitted information, and will modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. The ISO will report the final program participation values to the Market Participant by November 1, one month before the delivery period begins.

Market Participants that only wish to sell inventoried energy spot may also submit this information by the October 1 preceding the delivery period. In that case, the ISO's review and approval process will be completed before the delivery period begins on December 1, thereby ensuring that the Market Participant can sell inventoried energy via the spot settlement from the beginning of the delivery period. However, Market Participants that only wish to sell inventoried spot may also submit this information any time after October 1 and through the end of the relevant winter period. In such cases, the ISO will complete its review and approval process as soon as practicable, at which point the Market Participant's prospective participation associated with this inventoried energy may begin.

Q: Are Market Participants required to have inventoried energy at the time they submit this information to the ISO?

A: No. When submitting the election information described above to the ISO, the Market Participant is not required to have inventoried energy available for use. At that time, the Market Participant is only required to demonstrate its capability to hold inventoried energy per the terms of the program. This is consistent with the program's aim to incent the resource to have the inventoried energy on the Inventoried Energy Days when it is more likely to contribute to the region's winter energy security, rather than at the time when it elects to participate in the program.

For example, at the time the election information is submitted to the ISO, an oil resource would be required to demonstrate that it had the ability to store oil (say, in an on-site tank) in the claimed quantity that could be converted into electric energy during the delivery period. However, it would not actually have to have the oil in the tank at that time. Similarly, a gas resource may include a contract for the firm delivery of natural gas as part of the information submitted to participate in the program, but the contract need not allow the Market Participant to call gas at the time of submission, but it must provide for the firm delivery of gas during the delivery period.

Q: Why does the program include an October 1 deadline for the forward sale of inventoried energy?

A: The October 1 deadline will allow the ISO time to complete the review and approval process for all Market Participants seeking to sell inventoried energy forward before the start of the delivery period. This deadline therefore ensures that any inventoried energy sold forward is available at the start of the delivery period. If the program were to allow Market Participants to sell inventoried energy forward after the start of the delivery period, they would necessarily be selling forward for only a portion the delivery period (such as for the month of February). This could create ‘money for nothing’ concerns where Market Participants sell inventoried energy forward for a portion of the delivery period that is less likely to have Inventoried Energy Days (such as towards the end of February), and where system conditions may be less likely to be stressed.

Q: Why does the program allow Market Participants to sell inventoried energy spot after this deadline?

A: This ‘money for nothing’ concern associated with the forward sale of inventoried energy for just a portion of the delivery period does not occur if a Market Participant sells its inventoried energy via the spot settlement, and providing this flexibility may increase the available inventoried energy during the delivery period, which may improve the region’s winter energy security. The participant’s spot settlement compensation will be directly proportional to the number of Inventoried Energy Days that occur when this inventoried energy is maintained. As a result, if this inventoried energy only becomes available toward the end of February, its compensation will be directly proportional to the number of Inventoried Energy Days on which it is maintained. The participant can therefore not earn ‘money for nothing’ because it will only be paid for its inventoried energy on Inventoried Energy Days, where system conditions are more likely to be stressed and this inventory is more likely to improve the region’s winter energy security.

Q: Are there any additional requirements for Market Participants that seek to sell inventoried energy forward?

A: Yes. A Market Participant that seeks to sell inventoried energy forward must demonstrate the ability to maintain this inventoried energy for the entire delivery period. With a forward sale, the participant is taking on a financial obligation to maintain this quantity of inventoried energy during each Inventoried Energy Day that occurs across the delivery period. It is therefore appropriate to require that the resource demonstrate the ability to meet this financial obligation.

Q: What information about program participation will the ISO provide Market Participants?

A: After the ISO has completed its review and approval process for all of the submittals seeking to sell inventoried energy forward, the ISO will post to its website the total quantity of inventoried energy sold forward, and the total quantity sold forward associated with LNG-based gas contracts.

B. Information Submitted for Each Inventoried Energy Day

Q: What information must a Market Participant provide after each Inventoried Energy Day to determine its spot settlement?

A: A Market Participant must measure and report to the ISO the usable inventoried energy for each of its assets, in MWh and in units appropriate to the fuel type, between 7:00 a.m. and 8:00 a.m. on the morning after the Inventoried Energy Day.

Q: How does the program treat cases where the Market Participant does not provide this information as required?

A: If the Market Participant does not provide all of the information regarding its usable inventoried energy for a resource as required, the resource is assumed to maintain 0 MWh of inventoried energy for the Inventoried Energy Day, and is credited as such in the spot settlement.

Q: Why is this measurement made between 7:00 a.m. and 8:00 a.m. on the morning after the Inventoried Energy Day?

A: Measuring inventoried energy after the Inventoried Energy Day reduces the administrative burden associated with the program. It may be burdensome for Market Participants to measure inventoried energy for some assets, notably those that must be measured manually. By requiring this measurement after the Inventoried Energy Day has concluded, Market Participants are only required to do this measurement on mornings following Inventoried Energy Days. If the program instead required measurement and reporting during the Inventoried Energy Day, resources would have to measure this value on every day that could potentially be an Inventoried Energy Day, and this would increase the administrative burden associated with participating in the program.

Additionally, recall that the program is likely to introduce new opportunity costs in the energy market for resources that convert inventoried energy to electric energy. (The rationale behind these opportunity costs, and how they impact the dispatch of the system, is discussed in more detail in Part IX.C of this testimony.) Generally, resources incur an opportunity cost from converting inventoried energy into electric energy up to the time where their inventoried energy is measured for an Inventoried Energy Day. By measuring this inventory after the Inventoried Energy Day has concluded, the program will ensure that this opportunity cost is included for the duration of the Inventoried Energy Day. This measurement time will therefore provide resources with a strong financial incentive to maintain inventoried energy during the Inventoried Energy Day, which will allow this inventoried energy to be available if stressed system conditions occur toward the end of day, or continue after the day has concluded.

Q: Does the program allow Market Participants to be credited with inventoried energy when they have fuel that can be accessed by several resources at the same time?

A: Yes. There are multiple potential scenarios in which the same inventoried energy may be available to several resources at the same time. For example, there may be oil in a tank that can be accessed by multiple generators simultaneously. Similarly, a gas contract may allow the gas to be deliverable to multiple generators. The program allows Market Participants to be credited with inventoried energy for such fuel, even if it cannot be easily mapped to a specific resource. Unless the participant proposes a different methodology to map the fuel to resources, the program will assign this fuel to the resource or resources that will maximize the inventoried energy for which the Market Participant is credited. This is done by first assigning the fuel to the most efficient resource that can use it. If there is fuel left over, it is then assigned to the next most efficient unit. This continues either until all of the units have been assigned their maximum quantity as determined by their maximum potential output and the maximum duration, or all of the fuel has been assigned.

This process can be illustrated with a simple example. Imagine that a Market Participant has an oil tank that can serve two resources simultaneously. Efficient Resource A has a maximum potential output of 100 MW and a low heat rate. Inefficient Resource B has a maximum potential output of 200 MW and a high heat rate. When allocating this oil to these two resources, the program first assigns oil to efficient Resource A up until the point it where there is no usable oil remaining or Resource A has been credited with its maximum amount of 7,200 MWh of inventoried energy (100 MW × 72 hours). If, after the assignment of this oil to Resource A, there is still more oil in the tank, this additional oil is assigned to Resource B up to its maximum quantity of 14,400 MWh (200 MW × 72 hours).

Q: Does the program allow a resource to be credited with inventoried energy from multiple types of fuel if each meets the conditions outlined earlier?

A: Yes. For example, if a dual-fuel resource has dedicated oil in a tank and a contract for natural gas that meets the conditions outlined in Part VIII.B of this testimony, it can be compensated for both types of inventoried energy in the forward and spot settlements. However, as with resources that only use one type of fuel, the total inventoried energy for which it can be credited is limited to the product of its maximum potential output and the maximum duration of 72 hours.

Q: How does the program account for resources that are unavailable on the Inventoried Energy Day?

A: Recall that the maximum duration caps the amount of inventoried energy that a resource can sell at the product of its maximum potential output and 72 hours. If the resource is unavailable on the Inventoried Energy Day, its maximum potential output on this day is equal to 0 MW. As a result, the resource will be credited with 0 MWh of inventoried energy (the product of its maximum potential output and 72 hours). This treatment creates strong incentives for resources to be available on Inventoried Energy Days, where system conditions are more likely to be stressed, and energy is more likely to improve winter energy security.

Q: How does program account for resources that are partially available or unavailable for a portion of the Inventoried Energy Day?

A: In specifying the maximum amount of inventoried energy a resource can sell, the maximum potential output is calculated as the average value over the course of the Inventoried Energy Day. As a result, if a resource's maximum potential output is 80 percent of its normal value for the entire Inventoried Energy Day, the maximum quantity of inventoried energy with which it can be credited is equal to 80 percent of its normal value. Similarly, if the resource is fully available for 12 hours of the Inventoried Energy Day, and unavailable for the other 12 hours of the Inventoried Energy Day, the resource can be credited with up to 50 percent of the value it could have received if it was available for the entire day.

Q: Is a resource's maximum potential output adjusted in cases where its inventoried energy is not accessible on the Inventoried Energy Day?

A: Yes. In cases where the inventoried energy is not accessible on the Inventoried Energy Day, the resource's maximum potential output is set to 0 MW to reflect this. For example, if the resource has a contract for the firm delivery of gas with an LNG facility that is unable to vaporize and deliver the gas, the resource would not be credited with inventoried energy even if the resource was able to procure gas from another source.

Similarly, if the contract is with a buoy where an LNG tanker would directly inject vaporized gas into the pipelines and no such tanker is stationed at the buoy, the resource would not be credited with inventoried energy. This treatment will help prevent scenarios in which the program pays for inventoried energy on Inventoried Energy Days that is not available and therefore is not contributing to the region's winter energy security. Moreover, this provision is consistent with the program's requirement that the resource be able to convert its inventoried energy into electric energy at the ISO's direction.

Q: Does the program reduce a resource's maximum potential output in cases where the resource is available, but not able to operate (to its typical maximum) because of transmission limitations?

A: No. A resource's maximum potential output is not reduced in such cases for two reasons. First, reducing a resource's maximum potential output to reflect this transmission limitation would add significant complexity to this interim program while potentially reducing its transparency. More specifically, it would require the ISO to estimate how transmission limitations would impact the maximum potential output of resources that are offline but available.

Second, this could potentially create perverse bidding incentives in the energy market that are inconsistent with the efficient dispatch of the system and that would undermine the program's aim of improving winter energy security. For example, imagine that a transmission limitation meant that only one of two assets can produce energy: Resource A, a less efficient asset that uses inventoried energy, or Resource B, a more efficient asset that does not use inventoried energy. If Resource A is only credited with inventoried energy if it generates in this scenario (and therefore does not have its maximum potential output reduced due to the transmission limitation), it would have an incentive to reduce its energy market offer price below its true costs. This outcome would be plainly inefficient as it leads to the higher-cost resource being dispatched. Furthermore, it would lead to Resource A's inventoried energy being used when non-inventoried energy from Resource B is available, and this would therefore be inconsistent with the program's second design objective, as it would reduce the total inventoried energy available to meet stressed system conditions in a later period.

Q: Does this conclude your testimony?

A: Yes.

I declare, under penalty of perjury, that the foregoing is true and correct to the best of my knowledge, information, and belief.

Executed on March 25, 2019.

Christopher Geissler, Ph.D.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	))))	Docket No. ER19-_____-000

TESTIMONY OF TODD SCHATZKI
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position and business address.

A: My name is Todd Schatzki. I am a Vice President at Analysis Group, Inc. My business address is 111 Huntington Avenue, 14th Floor, Boston, Massachusetts 02119.

Q: Please describe your work experience and educational background.

A: I am an economist with expertise and experience in energy and environmental economics and policy. My experience in energy market and regulation includes wholesale and retail electricity markets, natural gas markets, and other fuels markets. In wholesale electricity markets, I have worked on the design of energy, capacity and ancillary service markets, evaluation of the performance of existing market rules, analysis of market impacts from changes in market rules or system infrastructure, and analysis of resource operational performance. I have worked with the independent system operators in New England and

New York, and other work has involved the markets run by the California Independent System Operator, Midcontinent Independent System Operator, the PJM Interconnection, the Southwest Power Pool, and the Alberta Electric System Operator. I have submitted testimony or evidence to state, provincial (Canada) and federal energy commissions. My Curriculum Vitae is provided as Attachment A to my testimony.

II. PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the calculation of the forward settlement rate for the interim inventoried energy program filed here by ISO New England Inc. ("ISO"). I also provide an estimate of the annual costs of the interim inventoried energy program. Attachment B to my testimony, a memorandum titled "Calculation of Rate for Interim Compensation Program," provides a detailed description of the data, assumptions, and methods used to calculate the forward settlement rate. This memorandum was prepared by me and my colleague Christopher Llop at the ISO's request specifically for the inventoried energy program. We presented the memorandum and responded to questions from New England stakeholders at two recent meetings of the NEPOOL Markets Committee.

III. FORWARD SETTLEMENT RATE

Q: What is the basis for the forward settlement rate?

A: The forward rate is set to fully compensate a market participant with a gas-fired resource (with an intermediate heat rate) for the expected costs of providing inventoried energy by holding a forward contract for natural gas supply delivered by a liquefied natural gas (“LNG”) terminal.

Q: Was this the only approach to providing inventoried energy considered?

A: No. The forward LNG contract was selected based on an analysis of available options for gas-only resources to secure energy supply. That analysis found that a forward LNG contract is the most viable, least-cost approach for gas-only resources to procure incremental inventoried energy. The analysis also considered fuel purchases by oil-only and dual-fuel resources incremental to the quantities that they otherwise would have purchased absent the inventoried energy program. The estimated cost of such incremental fuel purchases is lower than the estimated forward LNG contract cost, indicating that the program rate should be sufficient to incent oil-only and dual-fuel resources to participate in the program and add incremental fuel inventory (subject to on-site storage limits).

Q: What is the estimated rate?

A: The proposed rate, reflecting the expected cost of supplying inventoried energy through the forward LNG contract, is $82.49 per megawatt-hour of inventoried energy. Setting the rate at $82.49 per MWh of inventoried energy would fully compensate a market participant with a gas-fired resource (with an intermediate heat rate) for entering into a forward LNG contract for the purposes of supplying inventoried energy.

Q: What type of forward contract is assumed in your analysis?

A: The rate assumes a "call option" contract in which the contract holder pays an up-front reservation fee and has the option (but not the obligation) to purchase fuel when desired at a predetermined commodity price. The contract spans the winter months of December, January, and February. This type of contract and the contractual terms assumed in determining the rate are reasonable given common commercial arrangements in the fuels markets and incentives created by the program.

Q: What costs and revenues are accounted for in the estimated contract costs?

A: The contract requires a fixed cost to secure (or "reserve") the call options. These fixed costs are offset by two benefits. One benefit is the value of exercising a call option when the market price for natural gas is greater than the contract's commodity price. When the market price for natural gas exceeds the contract's commodity price, exercising the call option provides a gain equal to the difference between the natural gas market price and the commodity price. This gain can be realized by either selling the natural gas at the market price (but only paying the lower commodity price to obtain the fuel) or using the fuel to generate power (thus realizing the gain by reducing fuel purchase costs). The contract's value thus depends on natural gas prices, which will vary from year-to-year depending on weather conditions and other factors. The second benefit is the incremental net revenues from selling power into the New England markets when the market participant would otherwise be unable to obtain fuel due to illiquid fuel markets and thus could not supply electricity. Energy market prices are typically high during these periods when fuel markets are illiquid.

Q: How was the forward LNG contract price estimated?

A: The forward contract's reservation price and commodity price were determined such that the LNG terminal owner is indifferent between selling natural gas through a forward LNG contract and selling natural gas in the spot market. To estimate the expected returns when selling forward and selling spot, I used Monte Carlo analysis, which accounts for uncertainty in returns. The Monte Carlo approach estimates expected contract returns by simulating returns to forward and spot sales in each of 5,000 hypothetical winters. Natural gas prices vary in each winter depending on weather conditions and other factors. The simulated natural gas prices are randomly chosen from a distribution of natural gas prices based on historical prices in New England natural gas markets. The estimated reservation prices also account for cost and market factors that would cause the terminal to increase its reservation price, such as terminal operation and firm transmission costs, LNG terminal profits under different contract structures, and limits to the supply LNG terminals can offer. These factors are accounted for through a single comprehensive adjustment, not through multiple adjustments for each individual factor. The estimated forward contract terms are consistent with actual fuel contract terms I have reviewed, including those in the public domain.

Q: Do you account for the uncertainty of revenue streams in your estimates?

A: Yes. Estimates of the *expected* revenues earned by the contract holder account for uncertainty in the revenue streams through the same Monte Carlo approach used to estimate forward LNG contract prices. These expected returns also assume that the market participant reserves some of the contracted supply to participate in the inventoried energy program. Thus, the contract holder forgoes some energy market revenues to receive compensation through the program. Costs also include a risk premium to account for this uncertainty in financial returns to the contract holder.

Q: Did you test the sensitivity of your results?

A: Yes. Sensitivity analysis was performed in which certain key parameters of the forward LNG contract are varied from those used to calculate the forward rate. These sensitivities show that estimated costs depend on key parameters, but that reasonable changes to these parameters are unlikely to substantially change estimated costs. The sensitivity analyses performed do not account for all differences in the costs associated with different contract structures. If accounted for, these factors would tend to lower the estimated change in costs relative to those estimated quantitatively in the sensitivity analysis. For example, the sensitivity analysis found that a higher commodity price lowers the estimated net cost of the contract, largely due to a reduction in the reservation price. However, the quantitative analysis does not account for the fact that a contract with a higher commodity price is generally less profitable for the terminal, which would incent the LNG terminal owner to offer a higher reservation price, all else equal.

IV. <u>INTERIM INVENTORIED ENERGY PROGRAM COSTS</u>

Q: Have you developed an estimate of the inventoried energy program's total annual costs?

A: Yes. I have developed an estimate of the program's expected total annual costs reflecting payments made to resources that supply inventoried energy. This estimate assumes that all resources eligible to participate in the program sell the maximum quantity of inventoried energy allowed by the program at the forward rate of $82.49. As these assumptions reflect maximum program participation, in a sense, this estimate provides an upper bound on the program's potential costs, assuming forward settlement of all inventoried energy and no change in the region's infrastructure.

Q: What assumptions did you make regarding the quantity of inventoried energy supplied?

A: For eligible non-gas and dual-fuel resources, I assumed each resource supplies the maximum quantity of energy allowed under the program's rules. This quantity reflects resource-specific features, such as tank size or other metrics used to determine the quantity of energy eligible for compensation. This quantity is capped at 72 hours of inventoried energy, reflecting the "maximum duration" of inventoried energy that would be compensated. Estimated costs reflect data provided to me by the ISO, including resource-level fuel oil tank sizes and eligible inventoried energy from hydropower and pumped storage facilities. For gas-only resources, I assumed that the program incents resource owners to enter into forward contracts for LNG supply up to the maximum amount allowed under the program (560,000 MWh). All resources are assumed to maintain this quantity of inventoried energy for each Inventoried Energy Day, such that there are no spot deviations. Further detail on the eligibility and participation rules assumed in developing estimated costs are provided in the testimony of Dr. Christopher Geissler.

Q: What is the estimated total annual program costs?

A: I estimate the program's costs to be $148 million per year. The estimate corresponds to approximately 1.8 million MWh of inventoried energy sold forward and maintained during Inventoried Energy Days throughout the winter season.

Q: Could actual program costs be less than or greater than your estimated cost?

A: Yes. Actual program costs would differ from this estimate if actual program participation differs from assumptions made in developing the estimate. For example, less forward LNG contracting may occur than assumed in this estimate, resources may not supply the maximum eligible quantity of inventoried energy into the program, or resources may supply only a fraction of their capacity through forward settlement, which could lead to higher or lower payments if the actual number of Inventoried Energy Days differs from the number assumed in setting the forward settlement rate. Further discussion of the reasons why actual program costs may be less than or greater than this estimate are provided in the testimony of Dr. Christopher Geissler.

Q: Does this conclude your testimony?

A: Yes.

I declare, under penalty of perjury, that the foregoing is true and correct to the best of my knowledge, information, and belief.

Executed on March 25, 2019.

____

Todd Schatzki, Vice President, Analysis Group

Attachment A

TODD SCHATZKI, Ph.D.
VICE PRESIDENT
ANALYSIS GROUP INC.

Phone: (617) 425-8250
Fax: (617) 425-8001
todd.schatzki@analysisgroup.com

111 Huntington Avenue
Tenth Floor
Boston, MA 02199

Dr. Schatzki is an expert in energy and environmental economics and policy, and specializes in the application of microeconomics, econometrics, and data analysis to complex business and policy problems. He has worked with clients on corporate strategy, public policy design, and problems arising in regulation and litigation.

Dr. Schatzki has worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, utility ratemaking and retail electricity markets. He has submitted testimony to both state and federal energy commissions. His research has been supported by organizations such as the Electric Power Research Institute, Edison Electric Institute, Federal Energy Regulatory Commission, and National Association of Regulatory Utility Commissioners. His work has appeared in journals such as the *Journal of Environmental Economics and Management, the Electricity Journal, Public Utilities Fortnightly*, and *AEI-Brooking Joint Center for Regulatory Studies.* He has also provided litigation support in many cases, including several high profile cases involving alleged wholesale electricity price manipulation and the implications of such manipulation for derivative contracts.

Prior to joining Analysis Group, he had research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis (Vienna, Austria), and was an economist at LECG, LLC and National Economic Research Associates.

EDUCATION

1998 Ph.D., Public Policy, Harvard University, Cambridge, MA

Specialized Fields: Microeconomics, econometrics, industrial organization, natural resource and environmental economics

- Doctoral Fellow, Harvard University, Cambridge, MA (1993-1995)
- Crump Fellowship, Harvard University, Cambridge, MA (1995-1996)
- Pre-doctoral Fellow, Harvard Environmental Economics Program

1993 M.C.P., Environmental Policy and Planning (Urban Studies and Planning,), M.I.T., Cambridge, MA

1986 B.A., Physics, Wesleyan University, Middletown, CT

PROFESSIONAL EXPERIENCE

2005-present	Analysis Group, Inc.
2001-2005	LECG, LLC, *Managing Economist*
1998-2001	National Economic Research Associates, Inc., *Senior Consultant*
1997-1998	Harvard Institute for International Development, *Consultant*
1996-1997	Department of Economics, Harvard University, *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987-1991	Tellus Institute, *Research Associate*

SELECTED CASE WORK

Energy

- **New England Electricity Markets.** On-going, confidential analyses related to fuel security.
- **Global Crude Oil Producer.** Analysis of alternative approaches and contractual structures for marketing crude oil, including econometric analysis of customer price responsiveness.
- **New York Independent System Operator**. Evaluation of performance issues associated with capacity market resources and potential changes to market designs.
- ***Merced v. Barclays***. Analysis of alleged monopolization of western U.S. electric power markets.
- **ISO New England.** For the New England Power Pool (NEPOOL) 2016 Economic Analysis, analysis of Forward Capacity Market implications of alternative scenarios with varying assumptions about retirements and clean energy resources.
- **New England Electricity Markets.** Confidential assessment of interactions between state policies affecting electric power resources, including long-term contracts, and wholesale electricity markets.
- ***FERC v. Barclays***. Analysis of alleged manipulation of western U.S. electric power exchange markets.
- **New York Independent System Operator**. Demand curve reset for the New York ISO ICAP market including development annual updating process between resets and ICAP Demand Curve parameters.
- **Confidential Client.** Analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- **ISO New England.** Assessment of framework for evaluating capacity market offers from elective transmission projects for market mitigation.
- **Southwest Power Pool Power Suppliers**. Analysis and testimony related to the types of costs are appropriately short run marginal costs and thereby should be incorporated into energy market resource offers.

- **New York Independent System Operator**. Evaluation of capacity market rule changes including a forward market structure and multi-year price lock-in, including quantitative economic analysis of changes in market outcomes under alternative market structures.
- **Ameren Missouri**. Analysis of the economic impact of the Mark Twain Project, a new transmission project designed to support renewable energy requirements and other objectives (using PROMOD)
- **ISO New England.** Assistance to the ISO New England market monitor in the development of a de-list offer model consistent with new market rules.
- ***Zaremba v. Encana***. Evaluate operating agreements, the structure of the oil and gas industry, and trends in gas pricing in regards to antitrust claims in the market for oi land gas leases.
- **ISO New England.** Assistance in the development of a Winter fuel assurance programs for 2013/14, 2014/15 and 2015/16, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **Ameren Transmission.** Analysis of the impact of the Multi Value Project No. 16, a new transmission project, on energy market competition in Illinois (using PROMOD).
- **Vancouver Energy**. Assessment of economic impacts of a new energy distribution terminal, including change in economic activity, property value impacts and changes in rail congestion
- **ISO New England.** Assessment of the economic costs associated with winter 2013/2014 reliability programs, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **ISO New England.** Assessment of and testimony regarding the economic and reliability impacts of proposed capacity market rules introducing new performance incentives
- **ITC Midwest.** Analysis of and testimony regarding the LMP and production cost impacts of new transmission infrastructure (using PROMOD)
- **Entergy.** Evaluation of economic damages associated with an alleged contract breach
- **Ameren Transmission.** Analysis of the impact of the Illinois River Project, a new transmission project, on energy market competition in Illinois (using PROMOD)
- **Dayton Power and Light.** Evaluation of the aggregate benefits created by a proposed rate plan
- **Corporation with distribution companies across multiple jurisdictions.** Regulatory assessment considering current ratemaking models, regulatory environment and alternative ratemaking structures
- **ISO New England.** Assessment of the costs, feasibility and effectiveness of technical options to securing fuel supply for gas-fired generators
- **ISO New England.** Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies
- **Pacific Gas and Electric.** Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **Confidential Technology Company.** Analyzed the regional economic impacts of a prototype biofuels production facility at two potential development sites using the IMPLAN model.
- **ISO New England.** Statistical analysis of the performance of resources responding to system contingencies
- **Direct Energy.** Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions

- **ISO New England.** Assistance developing design enhancements for the region's Forward Reserve Markets
- **Confidential Client.** Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software)
- **Confidential Client.** Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software)
- **Confidential Regulated Utility.** Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development
- **Commonwealth Edison.** Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements
- **New England Power Generators Association.** Analysis of impacts of proposed electric power company merger
- **Confidential Technology Company.** Development of a quantitative model of energy savings associated with end-use technological modifications..
- **National Grid.** Development of an internal white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load and service challenges
- **EDF Group.** Analysis of financial and credit implications of the sale of a portion of power generation assets
- **New England States Committee on Electricity.** Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy
- **National Grid Utilities.** Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC.** Analysis of "best practices" in state policies for competitive procurement of retail electricity supply
- **New York ISO.** Analysis of single-clearing-price versus pay-as-bid market designs
- **Confidential System Operator.** Analysis of metrics for characterizing the economic value provided by regional transmission organizations
- **TransCanada.** Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts
- **New York ISO.** Analysis of market implications of fuel diversity issues
- **Confidential.** Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding
- **Confidential.** Financial and strategic analysis of gas supply contracting alternatives
- **Confidential.** Analysis of value of generating assets using real options analysis
- **Confidential.** Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts
- **Confidential.** Financial and strategic analysis of renewable generation technologies

Environment

- **Western States Petroleum Association.** Analysis of approaches to transitioning to long-run efficient climate policies.
- **Western States Petroleum Association.** Analysis of the implications of a GHG cap-and-trade market rule for other climate policies for the state of Oregon.
- **Western States Petroleum Association.** Analysis of key changes to California's GHG cap-and-trade market rule for the 2021 to 2030 compliance period.
- **Western States Petroleum Association and Chevron.** Analysis of key regulatory issues in the design of California's GHG cap-and-trade system for the 2021-2030 period.
- ***Florida v. Georgia.*** Analysis of economic issues related to current and proposed alternative apportionment of water between the states of Florida and Georgia before the U.S. Supreme Court.
- ***New Jersey DEP v. Occidental Chemical Corp. et al.*** One behalf of Maxus, assessment of reliability of analyses and conclusions reached regarding settlement of claims related to environmental contamination.
- **Chevron.** Development of a white paper on post-2020 climate policy for California
- ***C&A Carbon v. County of Rockland***. Support of expert testimony regarding violation of dormant interstate commerce clause.
- ***New Jersey DEP v. ExxonMobil***. Assessment of methods for valuation of environmental contamination.
- **American Petroleum Institute.** Assessment of issues related to the impact of changes to National Ambient Air Quality Standard Requirements on oil and gas exploration and production
- **Greater Boston Real Estate Board.** Development of a white paper on mandatory building energy labeling/benchmarking policies
- **Little Hoover Commission.** Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system
- **Exelon.** Analysis of the economic and market consequences of EPA's Clean Air Transport Rule
- **Chevron.** Assessment of lessons learned from Federal requirements for regulatory review for the potential development of state requirements
- **Western States Petroleum Association and Chevron.** Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board
- **Honeywell.** Analysis of proposed limits on HFC consumption under domestic climate policy
- **Electric Power Research Institute.** Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006)
- **Confidential.** Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs
- **Confidential.** Quantitative analysis of the impacts for technology, consumers and asset owners of a market-based domestic climate policy
- **Toyota.** Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements

- **Barajas Airport.** Evaluated the regional economic impacts of runway expansions at the Barajas airport in Spain

Finance and Commercial Damages

- ***Anderson et al. v. American Family Insurance***. Analysis of reliability of methodologies to estimate diminution in property value associated with remediated property damage.
- **Confidential Client.** Support during settlement, including analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- ***In the Matter of Current and Future Conditions of Baltimore Gas and Electric Company.*** Analysis of financial and credit implications of the sale of a portion of power generation assets
- ***Becarra et al. v. The Argentine Republic***. Analysis of bond pricing, transactions and holdings related to default of sovereign bonds
- ***Capital One Financial v. Commissioner of Internal Revenue.*** Analysis of transfers between financial institutions within credit card networks
- Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement
- Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product
- Analysis of damages from breach of commodity swap contract (petroleum)
- Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution

Antitrust

- Analysis of alleged monopolization of energy price indices
- Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement (retail consumer products)
- In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data
- Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement (retail consumer product)
- Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages (office systems)
- Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by DOJ and private parties
- Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents (scientific equipment)
- Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement (medical devices)
- Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent (scientific equipment)

ARTICLES AND PAPERS

"GHG Cap-and-Trade: Implications for Effective and Efficiency Climate Policy in Oregon," (with Robert N. Stavins), The Harvard Project on Climate Agreements, Discussion Paper 18-92, November 2018.

"Key Issues Facing California's GHG Cap-and-Trade System for 2021-2030" (with Robert N. Stavins), M-RCBG Faculty Working Paper 2018-02, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, 2018.

"Beyond AB 32: Post-2020 Climate Policy for California" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2014.

"Three Lingering Design Issues Affecting Market Performance in California's GHG Cap-and-Trade Program" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2013.

"Using the Value of Allowances from California's GHG Cap-and-Trade System" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"Implications of Policy Interactions for California's Climate Policy" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," (with Paul Hibbard), *The Electricity Journal*, May 2012.

"California's Cap-and-Trade Decisions," Forbes.com, August 19, 2010.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," (with Susan F. Tierney), *The Electricity Journal*, March 2009.

"Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation" (with Susan F. Tierney and Rana Mukerji), *Public Utilities Fortnightly*, March 2008.

"Free Greenhouse Gas Cuts: Too Good to Be True?" (with Judson Jaffe and Robert Stavins) VoxEU.org, January 3, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy" (with Robert N. Stavins and Judson Jaffe), AEI-Brookings Joint Center for Regulatory Studies, Related Publication 07-01. Jan 2007.

"Options, Uncertainty and Sunk Costs: An Empirical Analysis of Land Use," *Journal of Environmental Economics and Management*, Vol. 46, p. 86-105, 2003.

"The database on the economics and management of endangered species (DEMES)," (with David Cash, Andrew Metrick, and Martin Weitzman) in *Protecting Endangered Species in the United States: Biological Needs, Political Realities, Economic Choices*. Cambridge University Press, 2001

"The Issue of Climate," *Fundamentals of the Global Power Industry, Petroleum Economist, 2000.*

Review of "Sustainable Cities: Urbanization and the Environment in International Perspective," *Environmental Impact Assessment Review*, (Vol. 12, No, 4), 1993.

"Bottle Bills and Municipal Recycling," *Resource Recycling*, June 1991.

WORKING PAPERS

"Quality *and* Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes," June 23, 2014.

"Reliability and Resource Performance," May 16, 2012.

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," March 2012.

Schatzki, Todd, Paul Hibbard, Pavel Darling and Bentley Clinton, Generation Fleet Turnover in New England: Modeling Energy Market Impacts, June, 2011.

"A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," with William Hogan and Scott Harvey. Presented at the IDEI Conference on Competition and Coordination in the Electricity Sector, Toulouse, France, January 16-17, 2004.

"Estimating Structural Change in Industries with Application to Cartels," June 2003.

"The Pollution Control and Management Response of Thai Firms to Formal and Informal Regulation," (with Theodore Panayotou) draft, 1999.

"Differential Industry Response to Formal and Informal Environmental Regulations in Newly Industrializing Economies: The Case of Thailand," (with Theodore Panayotou and Qwanruedee Limvorapitak), Harvard Institute for International Development 1997 Asia Environmental Economics Policy Seminar, Bangkok, Thailand, February 1997.

"The Effects of Uncertainty on Landowner Conversion Decisions," John F. Kennedy School of Government, Center for Science and International Affairs, Environment and Natural Resources Program, Discussion Paper 95-14, December 1995.

REVIEW OF ACADEMIC ARTICLES

Economics of Energy & Environmental Policy, Ecological Economics, Journal of Environmental Economics and Management

SELECTED PRESENTATIONS

"Cost Containment – Which Cap-and-Trade Features Matter Most?", Climate Forum on California's Cap-And-Trade Program, International Emissions Trading Association, Carbon Market Compliance Association, Latham and Watkins, LLC, September 19, 2018.

"Northeast Power Markets Outlook: Addressing the Capacity and Reliability Crunch", "Natural Gas: Cross-Border Trade, Market Dynamics, and Infrastructure Woes", EUCI 4TH Annual U.S. Canada Cross-Border Energy Summit, March 12 – 13, 2018.

"Implications of the Expansion of "Non-Traditional" Resources for the Northeast Power Markets," Northeast Energy and Commerce Association's Power Markets Conference, November 14, 2017.

"The FERC's Anti-Market Manipulation Rule: Trends and Developments," The Knowledge Group, April 12, 2017.

"State Policy and Wholesale Power Markets: Emerging Issues Across the Markets," Northeast Energy and Commerce Association, Power Markets Conference, November 1, 2016.

"Net Metering," EUCI Workshop on Residential Demand Charges, October 20, 2016.

"Evaluating Carbon Risk Measures Under Policy Uncertainty," Workshop, EUCI U.S./Canada Cross-Border Power Summit, March 14-15, 2016.

"Implications of Policy Initiatives for Wholesale Markets," Northeast Energy and Commerce Association, Power Markets Conference, November 17, 2015.

"The Western United States' Impact On Global Climate Change Policy", 2015 WSPA Issues Conference, September 30, 2015.

"Capacity Performance (and Incentive) Reform" and "Out of Market Actions," EUCI Conference: Capacity Markets: Gauging Their Real Impact on Resource Development & Reliability, August 31-September 1, 2015.

"California Climate Goals for 2030 to 2050," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Local and Regional Climate Protection Efforts," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Current Regional Transmission Planning and Issues in New England," Law Seminar International Transmission in the Northeast, March 19, 2015.

"Stakeholder Assessment and Outlook for the Markets," Power Markets Conference, Northeast Energy and Commerce Association, October 20, 2014.

"Market Changes to Promote Fuel Adequacy – Capacity Markets to Promote Fuel Adequacy," moderator of panel discussion, Northeast Energy Summit 2014, September 17-19, 2014.

"Quality *and* Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes," Center for Research In Regulated Industries 27th Annual Western Conference June 26, 2014.

"Climate Policy Choices – RPS, Cap-and-Trade & the Implications for Actions (and Exits) that Affect Emissions," Electric Utilities Environmental Conference, February 4, 2014.

"Multiple Dimensions of Gas-Electric Coordination Concerns," Electric Utilities Environmental Conference, February 3, 2014.

"The Economics of Cap-and-Trade in the California Power Markets," EUCI Conference, California Carbon Policy Impacts on Western Power Markets, January 27, 2014.

"An Economic Perspective on Building Labeling Policies," Greater Boston Real Estate Board, April 26, 2013.

"Market-Based Policies to Address Climate Change," Sustainable Middlesex, May 4, 2013.

"Market Forces and Prospects/Economic Ripple Effects, 5-10 Years Ahead," Air & Waste Management Association, New England Section, October 12, 2012.

"Gas and Electric Coordination: Is It Needed? If So, To What End?" Harvard Electric Policy Group, Cambridge, MA, October 11, 2012.

"Reliability and Resource Performance," Center for Research In Regulated Industries 31st Annual Eastern Conference May 16, 2012.

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," International Industrial Organization Conference, Boston, MA, April 9, 2011.

"Ratemaking Mechanisms/Tools as Carrots for Achieving Desirable Regulatory Outcomes," Conference on Electric Utility Rate Cases, Law Seminars International, Boston, Massachusetts, November 9, 2010.

"Evolving Issues in Revenue Decoupling: Designs for an Era of Rising Costs," Center for Research In Regulated Industries 29th Annual Eastern Conference May 19, 2010.

"Aligning Interest with Duty: Revenue Decoupling as a Key Element of Accomplishing Energy Efficiency Goals," National Conference of State Legislatures, Fall Forum, December 8, 2009.

"Federal Proposals to Limit Carbon Emissions and How They Would Affect Market Structures – Regional Trading Programs' Futures in Light of New Federal Interest in Reducing GHG Emissions," Energy in California, Law Seminars International, San Francisco, California, September 15, 2009.

"Current Market, Technology and Regulatory Risks: Impact on Investment and Implications for Policy", Utility Rate Case, Issues and Strategy 2009, Law Seminars International, Las Vegas, Nevada, February 9, 2009.

"An Economic Perspective on the Benefits of Going Green," Harvard Electricity Policy Group, Atlanta, Georgia, December 11-12, 2008.

"Implications of Current Regulatory, Technology and Market Risks," Energy in California, Law Seminars International, San Francisco, California, September 22-23, 2008.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," National Association of Regulatory Utility Commissioners Summer Committee Meetings, Portland, Oregon, July 20, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy, Key Findings and Lessons Learned," POWER Research Conference on Electricity Markets and Regulation, University of California at Berkeley, March 21, 2008.

"Preliminary Findings: Study of Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," National Association of Regulatory Utility Commissioners Annual Meeting, Washington, D.C., February 17, 2008.

"The ABC's of California's AB 32: Issues and Analysis, Cost Analyses and Policy Design" Environmental Market Association Webinar, April 12, 2007.

SELECTED CONSULTING REPORTS

Capacity Resource Performance in NYISO Markets, An Assessment of Wholesale Market Options, (with Paul Hibbard and Sarah Bolthrunis), prepared for the New York Independent System Operator, October 2017.

Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios, An Element of the ISO New England 2016 Economic Analysis (with Llop, C.), prepared for ISO New England, July 3, 2017.

Study to Establish New York Electricity Market ICAP Demand Curve Parameters (Hibbard, P., Aubuchon, C., Berk, E. and Llop, C.), prepared for the New York Independent System Operator, June 2016.

NYISO Capacity Market: Evaluation of Options, (with Hibbard, P., Aubuchon, C., and Wu, C.), prepared for the New York Independent System Operator, May 2015.

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives (with Paul Hibbard), prepared for ISO New England, September 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis, with Rodney Frame and Pavel Darling, Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, April 9, 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project, with Rodney Frame and Pavel Darling, Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, March 22, 2013.

Analysis of Reserve Resources: Activation Response following Contingency Events, prepared for ISO New England, May 29, 2012.

Economic and Environmental Implications of Allowance Benchmark Choices (with Robert N. Stavins), prepared for the Western States Petroleum Association, October 2011.

Next Steps for California Climate Policy II: Moving Ahead under Uncertain Circumstances (with Robert N. Stavins), prepared for the Western States Petroleum Association, April 2010.

Options for Addressing Leakage in California's Climate Policy (with Jonathan Borck and Robert N. Stavins), prepared for the Western States Petroleum Association, February 2010.

Addressing Environmental Justice Concerns in the Design of California's Climate Policy (with Robert N. Stavins), prepared for the Western States Petroleum Association and the AB 32 Implementation Group, November 2009.

Next Steps for California with Federal Cap-and-Trade Policy On the Horizon (with Robert N. Stavins and Jonathan Borck), prepared for the Western States Petroleum Association, July 2009.

Evolving GHG Trading Systems Outside Its Borders: How Should California Respond? (with Robert N. Stavins and Jonathan Borck), prepared for the Western States Petroleum Association, July 2009.

Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, (with Susan Tierney) prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008.

Uniform Pricing versus Pay-as-bid: Does it Make a Difference?, (with Susan Tierney and Rana Mukerji) prepared for the New York Independent System Operator, March 2008.

Prospects for the U.S. Nuclear Industry, (co-author), prepared for a major Japanese electric power company, January 2001.

Costs and Benefits of Fish Protection Alternatives at Mercer Generating Station, (with David Harrison and Michael Lovenheim), prepared for Public Service Enterprise Group, September 2000.

Economic Evaluation of EPA's Proposed Rules for Cooling Water Intake Structures for New Facilities, (with David Harrison) prepared for the Utility Water Act Group, November 2000.

The Impacts of Revised Salem Refueling Schedules on the Wholesale and Retail Electric Market, (with David Harrison and Gene Meehan) prepared for Public Service Enterprise Group as a filing to New Jersey Department of Environmental Protection, September 2000.

Setting Baselines for Greenhouse Gas Credit Trading Programs: Lessons from Experience with Environmental and Non-Environmental Program, (with David Harrison) Electric Power Research Institute Report #1000147, December 2000.

Fueling Electricity Growth for a Growing Economy, Background Paper, (with David Harrison) prepared for the Edison Electric Institute, July 2000.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 2 Executive Report (Contributor), Electric Power Research Institute, Technical Report 1000097, December 2000.

Economic Evaluation of Alternative Revised Refueling Outage Schedules for Salem Power Plant, (with D. Harrison and J. Murphy), prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, July 2000.

Critical Review of "Economic Impacts of On Board Diagnostic Regulations," (with D. Harrison and S. Chamberlain) prepared for Alliance of Automobile Manufactures, January 2000.

Costs and Benefits of Alternative Revised Refueling Outage Schedules, (with D. Harrison and J. Murphy), prepared for Public Service Electric and Gas Company, July 1999.

Costs and Benefits of Fish Protection Alternatives at the Salem Facility, (with D. Harrison and J. Murphy) prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, March 1999.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 1 Executive Report, (Contributor) Electric Power Research Institute, February 1999.

Economic Benefits of Barajas Airport to the Madrid Region and the Neighboring Communities, (with D. Harrison, J. Garcia-Cobos, and D. Rowland) prepared on behalf of the Spanish Government, January 1999.

Costs and Benefits of Alternatives for Modifying Cooling Water Intake at the Hudson Facility, (with D. Harrison, D. Rowland and J. Murphy), prepared for Public Service Electric and Gas Company, November 1998.

Disposal Cost Fee Study, (with Frank Ackerman, Gretchen McClain, Irene Peters, and John Schall) prepared for the California Integrated Waste Management Board, 1991.

The Marginal Cost of Handling Packaging Materials in the New Jersey Solid Waste System, (with John Schall) prepared for The Council of State Governments and the New Jersey Department of Environmental Protection, 1990.

Energy Implications of Alternative Solid Waste Management Systems, (with Monica Becker and Allen White), prepared for the Northeast Regional Biomass Program, Coalition of Northeastern Governors Policy Research Center, 1990.

TESTIMONY AND OTHER FILINGS

Comments on Design for Alberta's Capacity Market, Written Evidence, Alberta Utilities Commission, Proceeding 23757, Consideration of ISO rules to implement and operate the capacity market, February 28, 2019.

Direct Testimony on behalf of Ameren Transmission Company of Illinois, Missouri Public Service Commission, Case No. EA-2017-0345, September 14, 2017.

Supplemental Affidavit on behalf of New York Independent System Operator, Federal Energy Regulatory Commission, Docket No. ER17-386- 000, December 21, 2016.

Affidavit on behalf of New York Independent System Operator, Federal Energy Regulatory Commission, Docket No. ER17-386- 000, November 18, 2016.

Pre-Filed Testimony on behalf of Vancouver Energy, Washington Energy Facilities Site Evaluation Council, Case No. 15-001, May 2016.

Surrebuttal Testimony on behalf of Ameren Transmission Company of Illinois, Missouri Public Service Commission, Case No. EA-2015-0146, November 16, 2015.

Affidavit on behalf of Joint Filing Group, Southwest Power Pool, Federal Energy Regulatory Commission, Docket No. ER15-2268-000, August 31, 2015.

Direct Testimony on behalf of Ameren Transmission Company of Illinois, Missouri Public Service Commission, Case No. EA-2015-0146, May 29, 2015.

Rebuttal Testimony on behalf of Ameren Transmission Company of Illinois, Illinois Commerce Commission, Docket No. 14-0514, March 5, 2015.

Rebuttal Testimony on behalf of MidAmerican Transmission Company, Illinois Commerce Commission, Docket No. 14-0494, March 5, 2015.

Direct Testimony on behalf of Ameren Transmission Company of Illinois, Illinois Commerce Commission, Docket No. 14-0514, August 21, 2014.

Direct Testimony on behalf of MidAmerican Transmission Company, Illinois Commerce Commission, Docket No. 14-0494, August 4, 2014.

Rebuttal Testimony on behalf of ITC Midwest LLC, Minnesota Public Utilities Commission, Docket No. CN-12-1053, April 25, 2014.

Direct Testimony on behalf of ITC Midwest LLC, Minnesota Public Utilities Commission, Docket No. CN-12-1053, February 24, 2014.

Testimony on behalf of the ISO New England, Federal Energy Regulatory Commission, Docket No. ER14-1050-001, February 12, 2014.

Affidavit on behalf of the ISO New England, Performance Incentives Market Rule Changes, Federal Energy Regulatory Commission, Docket No. ER14-1050-001, January 14, 2014.

Comments submitted to the California Air Resources Board Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program, August 2011 (with Robert N. Stavins).

Comments submitted to the Little Hoover Commission's Study of Regulatory Reform in California, January 2011 (with Robert N. Stavins).

Comments submitted to the California Air Resources Board Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program, December 2010.

Comments submitted to the California Air Resources Board Regarding Cost Containment Provisions of Preliminary Draft Cap-and-Trade Regulation, July 2010.

Comments submitted to the Economics and Allocation Advisory Committee, California Air Resources Board regarding draft report "Allocating Emissions Allowances Under California's Cap-and-Trade System," December 1, 2009 (with Robert N. Stavins).

Attachment B

Calculation of Rate for Interim Compensation Program

Todd Schatzki, Chris Llop, Analysis Group

January 30, 2019 (Revised)

1. Introduction

This memo describes the calculation of the forward settlement rate for the proposed Interim Compensation program. The forward rate is based on the estimated costs of providing inventoried energy by holding a forward contract for natural gas supply delivered by a liquefied natural gas (LNG) terminal. Based on analysis of options for gas-only resources to secure energy supply, we conclude that a forward LNG contract is the most viable, least-cost approach for gas-only resources to procure incremental inventoried energy, given the limited duration of the Interim Compensation program and potential restrictions arising from regulatory permitting.[1]

This memorandum is a revised version of a memorandum originally dated January 3, 2019.

2. Method

The estimated rate reflects the costs to a generator of entering into a forward LNG contract to provide inventoried energy. We assume that the generator enters into a forward contract with 10 call options. A call option contract is a common form of contractual arrangement with LNG terminals. We assume a contract with 10 call options, which strikes a balance between a contract with fewer call options, which may be preferred by a generator, and a contract with more call options, which may be preferred by a terminal. The generator supplies inventoried energy for the program's 3-day maximum duration by preserving 3 call options under all circumstances. Thus, the generator can exercise up to 7 call options.

The calculation of the benefits and costs of this contractual arrangement has three components:

1. Forward LNG contract costs, which includes the reservation charges net of any benefits from the exercise of call options;
2. Other generator costs associated with the contract, including credit costs and financial risk costs; and
3. Other generator benefits, notably incremental revenues from avoided reductions in supply into the ISO-NE energy and ancillary service (EAS) markets due to inability to procure fuel.

---

[1] Conversion to dual fuel is another viable option, although it requires upfront costs that must be recovered over multiple future years. Assuming cost recovery over the limited duration of the Interim Compensation, this option is less cost-effective than a forward LNG contract.

Calculation of Rate for Interim Compensation Program

The calculated forward rate using this methodology is $82.49 per MWh of inventoried energy. **Table 1** (provided at the end of the memorandum) summarizes the calculation of the forward rate, with additional details on the calculation, data, methods and assumptions provided below. In these calculations, benefits and costs are calculated in terms of dollars per MWh of inventoried energy secured through the forward call option contract.

a. Analysis of a Forward LNG Contract

A call option contract gives the holder the right to purchase a commodity at a predetermined strike price at any point in time. The key aspects of this contract structure are:

- Number of call options
- The Reservation Price – the price the holder has to pay for the call option
- The Commodity ("strike") Price – the predetermined price paid for natural gas when exercising the call option

The net cost of the forward LNG Contract reflects two components:

1. Cost of purchasing the contract, captured by the Reservation Price.
2. Net revenues from exercising the call options, which reflects arbitrage profits given the difference between the Commodity Price and spot natural gas price when the option is exercised.

These costs and benefits are estimated through Monte Carlo simulation. The analysis makes the following assumptions:

- **Forward LNG Contract.** We assume a contract with the following characteristics:
    - 10 call options
    - Commodity Price of $10/MMBtu
    - Calls can be exercised over a 90-day winter period, December 1 through February 28. We assume 60 trading days given weekends and holidays.

  A Commodity Price of $10/MMBtu is assumed to approximate LNG prices (inclusive of terminal costs) with some opportunity for modest future growth in LNG price.

- **Gain from option exercise.** The gain from call option exercise equals the difference between the spot natural gas price and the Commodity Price at the time the call is exercised. This gain can be realized by the contract holder through either savings in natural gas costs used to generate electricity or through sale of the natural gas on the spot market.

- **Natural gas prices.** The analysis simulates the realization of natural gas prices over 5,000 hypothetical 90-day winter periods, each with 60 trading days. In each simulation, daily natural gas prices equal the sum of the Henry Hub price and Algonquin-Henry Hub spread.

  The Henry Hub price is simulated assuming a Brownian process, with each day's price reflecting the prior day's price plus a randomly chosen daily day-ahead return. The starting price is $3.00 per MMBtu. The Algonquin-Henry Hub spread is simulated using a bootstrap method, sampling from past Algonquin-Henry Hub day-ahead spreads from the 2009/10 to 2016/17 winter periods. Simulations use day-ahead prices, as reliable time-series data for intra-day prices is not available.

- **Option exercise.** Because the call option contract has a finite number of call options, value is maximized by exercising call options when the natural gas price exceeds the Commodity Price by a sufficiently large threshold quantity – that is:

  Exercise the call option if: Commodity Price + Threshold > Spot Natural Gas price

  In principle, the threshold reflects the expected value of the foregone option. If the threshold is too small, the options are exercised on days when the gain is small; if the threshold is too large, the options are called too infrequently, leaving gains unrealized. We calculate the threshold computationally as the fixed threshold that maximizes total profit in expectation. The calculated threshold is $8.50 per MMBtu when exercising 7 call options. Thus, the model assumes that contract holder exercises a call option on any day where the modeled gas price exceeds $18.50 ($10 commodity price + $8.50 threshold).

We calculate an initial Reservation Price as the price that results in the contract providing no expected gain, reflecting a purely financial transaction. Based on the assumptions listed above, the initial Reservation Price is $10.38 per MMBtu.[2]

However, pricing for a physical contract with an LNG terminal may reflect other factors, including: LNG terminal variable operating costs; firm transmission rights; operational constraints created by the forward contract, which has a claim on the terminal's limited send-out capacity; opportunity costs compared to other contracts that offer greater reservation charges (e.g., multi-year contracts or contracts with a larger number of call options);[3] the limited number of options available to gas-only resources to secure natural gas supply; and the limited number of options for incremental fuel supply during tight natural gas

---

[2] Recent winter periods have seen relatively little forward contracting with LNG terminals by generators operating in the ISO-NE markets. Thus, it is reasonable to assume that net effect of all other revenues and costs incremental to this financially neutral price are negative, implying incremental net costs to generators and/or premia required by the LNG terminals.

[3] For example, total reservation charges, reflecting the Reservation Price and number of calls, are nearly 25% greater for a contract with 20 rather than 10 call options, while the larger number of call options does not further constrain contracts the terminal can enter into, which is limited by send-out capacity.

markets. Given these factors, we assume a 12.5% terminal adder, resulting in a Reservation Price for physical supply of $11.67.

Total reservation charges for the forward contract are calculated on a per MWh basis as:

$$Reservation\ Cost = Call\ Options\ Reserved * Reservation\ Price\ * Heat\ Rate$$

$$\$910.53/MWh = 10\ calls * \$11.67/MMBtu * 7.8\frac{MMBtu}{MWh}$$

We assume a heat rate of 7.8 MMBtu per MWh, which is within the range of average heat rates for combined cycle facilities in the region. We calculate the net revenues from exercise of the call option assuming that up to 7 call options are exercised, allowing the resource to supply 3 call options for Interim Compensation. Net revenues from exercise of the 7 call options are calculated using the Monte Carlo model. Net revenues reflect the difference between the simulated spot natural price and the Commodity Price ($10 per MMBtu). We find that the expected net revenue per call option is $12.58 per MMBtu, when 7 call options can be exercised.

The total expected value of the exercised call options is:

$$Net\ Fuel\ Market\ Value = Net\ Revenues\ per\ Call * Call\ Options\ Exercised * Heat\ Rate$$

$$\$687.09/MWh = 7\ calls * \$12.58/MMBtu * 7.8\frac{MMBtu}{MWh}$$

This estimate reflects the use of the optimal exercise threshold, and thus provides a conservative (larger) estimate of the expected net revenues likely to be realized.

b. Other Generator Costs

Generators may face additional costs to entering into a forward contract not captured in the net cost of a forward LNG contract, as described above. We consider two additional costs: credit costs, and financial risk and other transaction costs.

Credit cost reflect the cost to establishing credit that terminal counterparties may demand from generators prior to entering into the forward LNG contract. We assume these costs reflect 3% of total reservation costs, based on reported costs of securing credit for independent power producers. The resulting credit costs are:

$$Credit\ Costs = Reservation\ Cost * 3\%\ Assumed\ Cost\ of\ Securing\ Credit$$

$$\$27.32 = \$910.53 * 3\%$$

Financial risk and other transaction costs include the increased financial risk to generators from holding a forward LNG contract.[4] For a natural gas-only generator, a call option contract would increase the variation in financial returns because returns to the contract and the resource are positively correlated (i.e., returns to both are higher during winters with high natural gas prices). Assuming that corporate financial risk is related to the variation in financial returns, the contract increases corporate financial risk.[5] We assume that this cost equals 10% of the reservation costs.[6] As a result, the financial risk and other costs are:

$$Financial\ Risk\ and\ Other\ Costs = Reservation\ Cost * 10\%\ Assumed\ Risk\ and\ Costs$$

$$\$91.05 = \$910.53 * 10\%$$

c. Other Benefits: Incremental ISO-NE Revenues

A forward LNG contract would improve resource performance, leading to incremental revenues from supplying into the ISO-NE markets. With a forward contract, generators can avoid the risk that fuel cannot be procured due to illiquidity in the natural gas market. These ISO-NE revenues would be incremental to the net revenues from call option exercise discussed above, as they reflect improved performance, rather than arbitrage of fuel prices.

Our estimates of incremental ISO-NE revenues reflect increased performance during operating reserve shortages (i.e., Capacity Scarcity Conditions, or CSC). A forward LNG contract may also provide incremental ISO-NE revenues when there is not an operating reserve shortage, although analysis indicated that these net revenues would be much smaller in expectation. Incremental ISO-NE revenues are estimated for both medium and high winter scarcity conditions, and the results are averaged based on an assumption regarding the likelihood that either occur.

Estimates incremental ISO-NE revenues include two components:

1. Incremental revenues from avoided day-ahead supply reduction ($/MW) during CSC Hours with day-ahead market illiquidity:

$$(LMP + PFP + RCPF - \mathrm{MC}) \times C_{DA} \times U_{DA} \times Hrs_{DA}$$

---

[4] We assume a contract signed in the summer months in advance of the winter season.

[5] In principle, the relationship between the volatility of returns and a firm's financial risk will depend on multiple factors, such as the risk tolerance of corporate management, other risk management and hedging activities, and other physical and business assets owned.

[6] Given the complexity of this forward call option contract, its financial risks are not easily hedged.

2. Incremental revenues from avoided real-time supply reduction ($/MW) during all CSC Hours:

$$(LMP + PFP + RCPF - MC) \times C_{RT} \times U_{RT} \times Hrs_{RT}$$

While revenues account for both avoided day-ahead and real-time supply reduction, both are associated with those real-time hours where there are not sufficient reserves available in the system.

Assumptions used in the analysis are provided below. Because incremental ISO-NE revenues from improved performance will differ across units, our estimates reflect averages calculated over an appropriate set of gas-only resources.[7]

- **Locational Marginal Price (LMP) (**$/MWh). The LMP is $392/MWh and $241/MWh under high and medium winter severity conditions, reflecting assumed natural gas price ($50.20/MMBtu and $30.86/MMBtu, respectively) and a marginal gas-fired generator with a heat rate of 7,800 Btu/kWh. Natural gas price estimates reflect average prices during certain past peak winter conditions. The marginal heat rate is chosen as representative of marginal heat rates during tight winter gas periods.

- **Pay for Performance (PFP).** The PFP payment rate is assumed to be $3,500/MWh.[8]

- **Reserve Constraint Penalty Factor (RCPF) (**$/MWh). We assume a mix of 10-minute non-spinning and 30-minute operating reserve shortages that results in an average (combined) shortage price of $1,500.

- **Marginal Costs (MC) (**$/MWh). Estimated marginal costs are $378/MWh and $233/MWh under high and medium winter severity conditions, reflecting a gas-fired combined cycle unit with a heat rate of 7,500 Btu/kWh. This heat rate is lower than the average heat rate of 7,800 Btu/kWh due to higher plant utilization during the more severe winter conditions. In effect, our analysis assumes a spark spread reflecting a 300 Btu/kWh heat rate spread.

- **Inability to Procure Intraday Gas (C_{RT})**: We assume that the intraday gas market is illiquid, thus limiting a generator's ability to procure fuel to fulfill a real-time deviation, and there is a 50% likelihood that the system operator requests the generator to supply a positive real-time deviation.

---

[7] The value of fuel call options will differ across resources based on several factors including the magnitude and frequency of real-time deviations from day-ahead positions, day-to-day variation in day-ahead positions and commitment, and geographic variation in natural gas supply liquidity.

[8] Avoided day-ahead supply restrictions result in incremental PFP payments because day-ahead illiquidity in natural gas supply also prevents the resource from supplying in the real-time market. As a result, the resource would be unable to supply during CSC hours.

- **Inability to Procure Day-Ahead Gas (C_{DA})**: We assume that the day-ahead market is illiquid in a fraction of CSC hours. On these days, absent a forward contract, we assume that there is a 10% and 20% risk the generator cannot procure fuel day-ahead during medium and high winter scarcity conditions, respectively.

- **Incremental Real-Time Utilization (U_{RT})**: Positive real-time deviations are 15% of capacity, based on actual real-time deviations during historical periods with tight natural gas conditions (periods when the Algonquin spot price exceeds $20/MMBtu between the 2012/2013 and 2017/2018 winters).

- **Day-Ahead Utilization (U_{DA})**: Day-ahead utilization is 55% day-ahead during CSC hours, based on actual resource utilization during periods with tight natural gas conditions (periods when the Algonquin spot price exceeds $20/MMBtu between the 2012/2013 and 2017/2018 winters).

- **Hours of Intraday Market Illiquidity during Capacity Scarcity Conditions** (***Hrs_{RT}***): We assume 10 and 50 hours of illiquidity in intraday natural gas markets during Capacity Scarcity Conditions for medium and high winter scarcity conditions, respectively.

- **Hours of Day-Ahead Market Illiquidity during Capacity Scarcity Conditions** (***Hrs_{DA}***): We assume 8 and 40 hours of market of day-ahead market illiquidity during Capacity Scarcity Conditions for medium and high winter scarcity conditions, respectively.

Estimated incremental ISO-NE revenues reflect assumptions about the likelihood that medium and high winter scarcity conditions occur. We assume a 20% likelihood of medium winter gas scarcity conditions and a 5% likelihood of high winter gas scarcity conditions, which reflect assumed probabilities, not based on any probabilistic modelling. These probabilities are shown in **Table 2**, along with assumptions about: the average natural gas spot price during shortage conditions, and the number of hours with intraday and day-ahead gas market illiquidity during CSC hours.

Table 2: ISO-NE Shortage Hours and Natural Gas Market Assumptions

			During CSC Hours	
Winter Gas Scarcity Conditions	**Probability of Winter Condition**	**Algonquin Spot Price ($/MMBtu)**	**Hours of Intraday Market Illiquidity**	**Hours of Day Ahead Market Illiquidity**
Medium	20%	$30.86	10	8
High	5%	$50.20	50	40

Table 3 below presents estimated incremental ISO-NE revenues. We find that the incremental revenues are $5,959/MW during medium and $40,861/MW during high winter scarcity conditions. Assuming the contract provides supply (per MW) for 24 hours for each call option, the benefit per MWh of inventoried energy is calculated by dividing the total incremental revenues by 240 (24 hours * 10 calls). Expected incremental ISO-NE revenues from an additional MWh of inventoried energy is thus $24.83/MW during medium scarcity conditions and $170.25/MW during high winter scarcity conditions.

Table 3: Calculation of Incremental ISO-NE Revenues ($ per MWh inventoried energy)

	LMP ($/MWh)	PFP ($/MWh)	RCPF ($/MWh)	Marginal Costs ($/MWh)	Gas Supply Risk (%)	Incremental Utilization (%)	Illiquid CSC Hours	Incremental ISO-NE Revenue ($/MW)
Medium Scenario								
Real Time	$241	$3,500	$1,500	$233	50%	15%	10	$3,756
Day Ahead	$241	$3,500	$1,500	$233	10%	55%	8	$2,203
High Scenario								
Real Time	$392	$3,500	$1,500	$378	50%	15%	50	$18,801
Day Ahead	$392	$3,500	$1,500	$378	20%	55%	40	$22,060

MWh provided by contract	240
Real Time + Day Ahead = Total Incremental Revenue (Medium Scenario)	$5,959
Incremental Revenue per MWh (Medium Scenario):	**$24.83**
Real Time + Day Ahead = Total Incremental Revenue (High Scenario)	$40,861
Incremental Revenue per MWh (High Scenario):	**$170.25**

In expectation, given the probability that medium and high winter gas conditions occur, the expected value of an inventoried MWh of energy is $13.48/MW, calculated as follows:

$$Expected\ Value\ of\ ISO\text{-}NE\ Revenues = \sum Assumed\ Condition\ Probability * Revenues$$

$$\$13.48 = 20\% * \$24.83 + 5\% * \$170.25$$

Total expected incremental ISO-NE revenues is the expected value per MWh of inventoried energy multiplied by the number of call options not reserved for supplying inventoried energy under the Interim Compensation program:

$$Incremental\ ISO\text{-}NE\ Revenues = Expected\ Value\ of\ ISO\text{-}NE\ Revenues * Call\ Options\ Exercised$$

$$\$94.35 = \$13.48 * 7\ calls$$

3. Calculating a Forward Rate

Table 1 summarizes the calculation of the forward rate. The calculations are performed on a per MWh basis. Each call option requires 7.8 MMBtu of natural gas per MWh. The total cost reflects the product of the number of calls, the energy (MMBtu or MWh) per call and the corresponding unit benefit or cost.

The net fuel market value reflects 7 call options, because 3 options are reserved for supplying Interim Compensation.

Total Benefits (Costs) are calculated as the sum of each of the components described above – that is:

Calculation of Rate for Interim Compensation Program

$$Total\ Benefits\ (Costs) = Net\ Fuel\ Market\ Value + Incremental\ ISO\text{-}NE\ Revenues$$

$$-\ Reservation\ Cost - Credit\ Costs - Financial\ Risk\ and\ Other\ Costs$$

$$-\$247.46 = \$687.09 + \$94.35 - \$910.53 - \$27.32 - \$91.05$$

Because the total cost reflects the cost of securing 3 MWh of energy inventory, the total cost is divided by 3 to get the unrecovered cost per MWh of energy inventory. Thus, the rate reflects the negative of this cost – that is:

$$Interim\ Program\ Forward\ Rate\ \left(\frac{\$}{MWh}\right) = -Total\ Benefits\ (Costs)/Administrative\ Days$$

$$\$82.49 = -(-\$247.46\ /\ 3)$$

The cost reflects expected cost over a range of simulated outcomes. **Figure 1** illustrates the distribution of net returns underlying these estimated costs. As described above, this distribution reflects net returns calculated in each of the 5,000 hypothetical winter periods, where the realization of natural gas prices differs in each winter. As shown, the mean of net returns is **-** $247.26 across simulations.

4. Sensitivity Analysis

Sensitivity analysis is performed in which certain key parameters of the forward LNG contract are varied from those used to establish the forward rate. In particular, we vary the number of calls, the Commodity Price and the Interim Compensation program's maximum duration. When performing sensitivity analysis, we vary the contract terms assumed in the Monte Carlo simulations, vary the number days of potential incremental ISO-NE revenues, and vary the program's maximum duration used to calculate required Interim Compensation payment needed to offset unrecovered costs. However, we do not vary other parameters used in calculating the cost of a forward LNG contract, including the terminal adder and generation financial risk and other costs, although changes in contract terms may affect the terminal's costs (i.e., the terminal adder) or the financial risk to generators.

Table 4 summarizes the results of the sensitivity analysis. **Tables 5 to 9** summarize the calculation of the forward rate for each of these sensitivity analyses.

We find that decreasing the number of calls, the Commodity Price or the program's maximum duration increases the forward rate, all else equal. As noted above, comparison between these rates and the proposed rate may not fully account for all differences in the costs associated with different contract structures, particularly certain terminal and generator costs. For example, while the estimated rate reduces to $41.60 when assuming a Commodity Price of $15 per MMBtu, the LNG terminal would likely impose a greater terminal adder on such a contract because the higher Commodity Price reduces terminal profitability.

Calculation of Rate for Interim Compensation Program

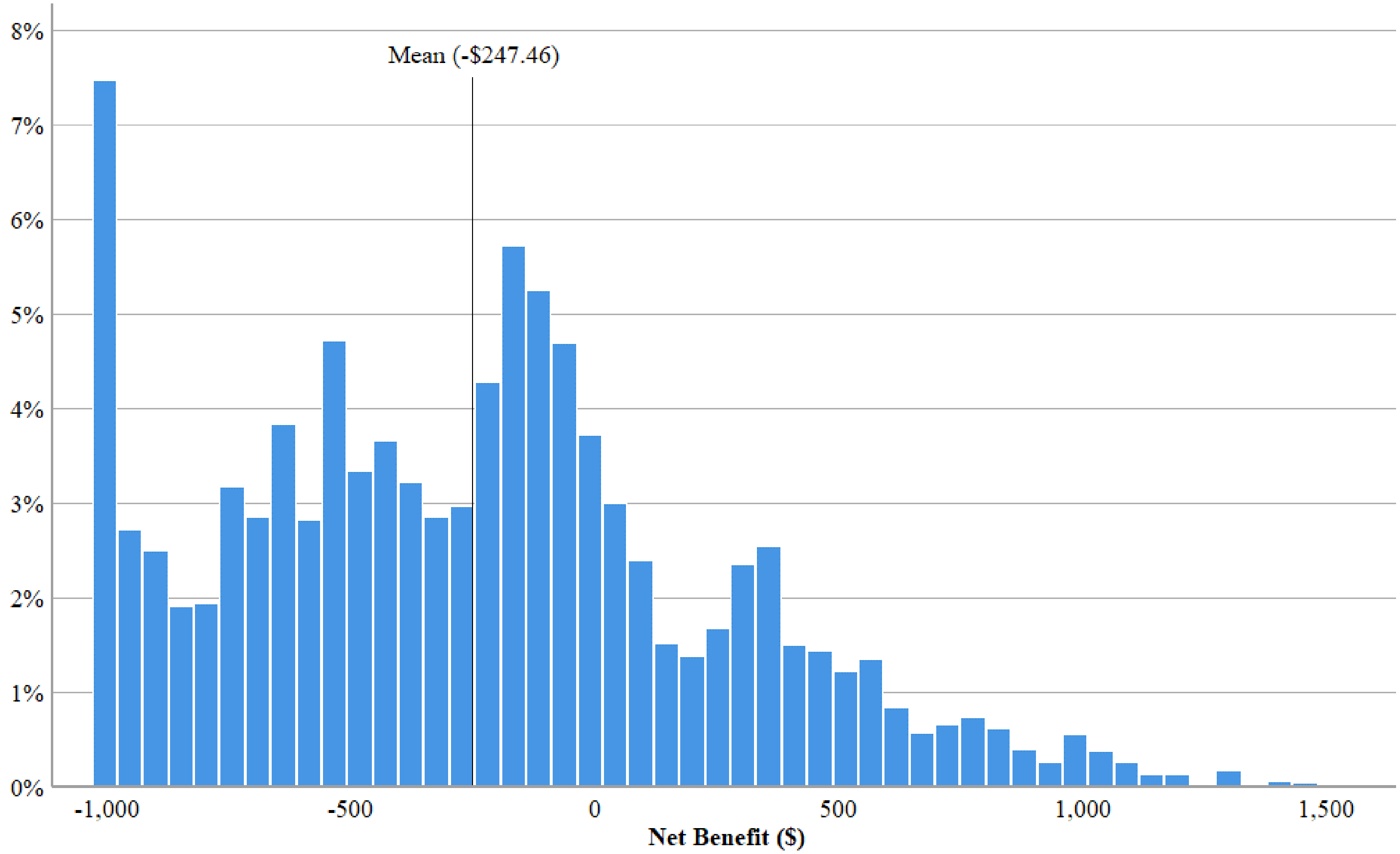
Calculation of Rate for Interim Compensation Program

Table 1: Summary of Estimated Cost of Inventoried Energy Supplied Through a LNG Forward Contract

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	Calculation
	[A]	[B]		[C]		[D]	
Costs							
Reservation Price	10	-$11.67	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$910.53	[1] = [A]*[B]*[C]
<u>Other Generator Costs</u>							
Credit Costs				3%	% of Total Reservation Price	-$27.32	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$91.05	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	7	$12.58	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$687.09	[4] = [A]*[B]*[C]
<u>Other Benefits</u>							
Incremental ISO-NE Revenues	7	$13.48	$/MWh			$94.35	[5] = [A]*[B]
Total Benefits (Costs)	3					**-$247.46**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$82.49**	[7] = – [6] / 3

Calculation of Rate for Interim Compensation Program

Figure 1: Distribution of Annual Return from Forward LNG Contract, Monte Carlo Analysis (N = 5,000)



Note: For each simulated winter, *t*, net returns is calculated for a contract with 10 calls, as: **-** (Reservation Price + Credit Costs + Financial Risk and Other) + (Net Fuel Market Value (*t*) + Incremental ISO-NE Revenues (*t*)).

Table 4: Interim Program Settlement Rate Sensitivity Analysis: Calculation of Forward Rate

	Parameters Varied in Sensitivities						
Sensitivity #	Number of Calls	Commodity Price ($/MMBtu)	Maximum Duration (Days)	Reservation Price ($/MMBtu)	Net Fuel Market Value ($/MMBtu)	Incremental ISO-NE Revenues ($/MWh)	Forward Rate ($/MWh)
Proposed Rate	10	$10.00	3	$11.67	$12.58	$13.48	$82.49
[1]	7	$10.00	3	$14.16	$16.06	$13.48	$106.14
[2]	10	$10.00	2	$11.67	$11.73	$13.48	$94.69
[3]	7	$10.00	2	$14.16	$14.72	$13.48	$115.96
[4]	10	$8.00	3	$13.32	$14.01	$13.48	$104.97
[5]	10	$15.00	3	$8.30	$9.38	$13.48	$41.60

Table 5: Calculation of Interim Program Forward Rate
Sensitivity #1: 7 Calls, 3 Day Maximum Duration, $10 Commodity Charge

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	Calculation
	[A]	[B]		[C]		[D]	
Costs							
Reservation Price	7	-$14.16	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$772.98	[1] = [A]*[B]*[C]
Other Generator Costs							
Credit Costs				3%	% of Total Reservation Price	-$23.19	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$77.30	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	4	$16.06	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$501.13	[4] = [A]*[B]*[C]
Other Benefits							
Incremental ISO-NE Revenues	4	$13.48	$/MWh			$53.91	[5] = [A]*[B]
Total Benefits (Costs)	3					**-$318.43**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$106.14**	[7] = – [6] / 3

Table 6: Calculation of Interim Program Forward Rate
Sensitivity #2: 10 Calls, 2 Day Maximum Duration, $10 Commodity Charge

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	
	[A]	[B]		[C]		[D]	Calculation
Costs							
Reservation Price	10	-$11.67	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$910.53	[1] = [A]*[B]*[C]
<u>Other Generator Costs</u>							
Credit Costs				3%	% of Total Reservation Price	-$27.32	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$91.05	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	8	$11.73	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$731.69	[4] = [A]*[B]*[C]
<u>Other Benefits</u>							
Incremental ISO-NE Revenues	8	$13.48	$/MWh			$107.83	[5] = [A]*[B]
Total Benefits (Costs)	2					**-$189.38**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$94.69**	[7] = – [6] / 2

Calculation of Rate for Interim Compensation Program

Table 7: Calculation of Interim Program Forward Rate
Sensitivity #3: 7 Calls, 2 Day Maximum Duration, $10 Commodity Charge

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	Calculation
	[A]	[B]		[C]		[D]	
Costs							
Reservation Price	7	-$14.16	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$772.98	[1] = [A]*[B]*[C]
Other Generator Costs							
Credit Costs				3%	% of Total Reservation Price	-$23.19	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$77.30	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	5	$14.72	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$574.16	[4] = [A]*[B]*[C]
Other Benefits							
Incremental ISO-NE Revenues	5	$13.48	$/MWh			$67.39	[5] = [A]*[B]
Total Benefits (Costs)	2					**-$231.92**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$115.96**	[7] = – [6] / 2

Table 8: Calculation of Interim Program Forward Rate
Sensitivity #4: 10 Calls, 3 Day Maximum Duration, $8 Commodity Charge

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	Calculation
	[A]	[B]		[C]		[D]	
Costs							
Reservation Price	10	-$13.32	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$1,039.06	[1] = [A]*[B]*[C]
<u>Other Generator Costs</u>							
Credit Costs				3%	% of Total Reservation Price	-$31.17	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$103.91	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	7	$14.01	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$764.87	[4] = [A]*[B]*[C]
<u>Other Benefits</u>							
Incremental ISO-NE Revenues	7	$13.48	$/MWh			$94.35	[5] = [A]*[B]
Total Benefits (Costs)	3					**-$314.92**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$104.97**	[7] = – [6] / 3

Table 9: Calculation of Interim Program Forward Rate
Sensitivity #5: 10 Calls, 3 Day Maximum Duration, $15 Commodity Charge

LNG Terminal Contract Cost/Benefit	No. of Calls	Cost/Benefit per Call ($/Unit)		Conversion to Total ($)		Total ($)	Calculation
	[A]	[B]		[C]		[D]	
Costs							
Reservation Price	10	-$8.30	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	-$647.29	[1] = [A]*[B]*[C]
Other Generator Costs							
Credit Costs				3%	% of Total Reservation Price	-$19.42	[2] = [C]* [1]
Financial Risk and Other				10%	% of Total Reservation Price	-$64.73	[3] = [C]* [1]
Benefits							
Net Fuel Market Value	7	$9.38	$/MMBtu	7.8	Heat Rate (MMBtu/MWh)	$512.27	[4] = [A]*[B]*[C]
Other Benefits							
Incremental ISO-NE Revenues	7	$13.48	$/MWh			$94.35	[5] = [A]*[B]
Total Benefits (Costs)	3					**-$124.81**	[6] = [1] + [2] + [3] + [4] + [5]
Interim Program Forward Rate (per MWh)						**$41.60**	[7] = – [6] / 3

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant’s share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year’s annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource’s Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant’s or Non-Market Participant Transmission Customer’s total debt (including all current borrowings) divided by its total shareholders’ equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant’s or Non-Market Participant Transmission Customer’s earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant’s or Non-Market Participant Transmission Customer’s credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a “material adverse impact” on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD’s Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the

Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and

ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO’s technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource’s Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource’s Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO’s administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

APPENDIX K

INVENTORIED ENERGY PROGRAM~~WINTER RELIABILITY SOLUTIONS~~

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

~~WINTER RELIABILITY SOLUTIONS~~

~~III.K.1. General.~~

~~(a) **Term.** This Appendix K is intended to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.~~

~~(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; modeled in the EMS; and either (i) dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.~~

~~(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.~~

~~(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.~~

~~(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.~~

~~(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 and III.K.3 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Notwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.~~

~~(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil.~~

~~i. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15, using the following formula:~~

$\cancel{\textit{Set Rate} = CC + OC + LC}$

$\cancel{CC = P_f \text{ x } r_{rf}}$

~~*Where:*~~
~~P_f: Next October fuel price (Diesel, DFO) (Source: NYMEX Futures)~~
~~r_{rf}: Risk-free return set at 0.73%~~

~~OC = October 12-month put option premium calculated using K, S, σ~~

~~*Where:*~~
~~K: Strike Price = P_f~~
~~S: Price at expiry (*i.e.*, price 12-months from P_f) (Source: NYMEX Futures)~~
~~σ: Implied volatility on fuel put options on futures contracts (Source: Bloomberg)~~

$\cancel{LC = P_f \text{ x } R}$

~~*Where:*~~
~~R: the implied risk premium on the after-tax weighted average cost of capital (*i.e.*, WACC – r_{rf}) (Source: ISO-NE Sloped Demand Curve filing)~~

~~ii. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas.~~

~~iii. The Set Rate for the demand response service in Section III.K.4 shall be calculated as follows:~~

$$\cancel{\textit{DR Set Rate} = R_o \times [(1/H_{avg}) \times HR_g \times 100MW \times 180_h]/(100{,}000\ kW \times 3\ months)}$$

~~*Where:*~~

~~R_o: Oil program Set Rate in \$/bbl~~
~~H_{avg}: MW-Weighted average heat content of oil-fired units in New England = 6.0 MMBtu/bbl~~
~~HR_g: Generic heat rate = 10 MMBtu/MWh~~
~~180_h: 180 hours, which is the maximum number of hours a demand response asset could be dispatched during the winter~~

~~(h) **Conflict.** Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.~~

~~III.K.2. Oil Fuel.~~

~~Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.~~

~~Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety-fill and structural limitations. Tanks removed from service due to structural damage or for long-term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.~~

~~(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil.~~

~~(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to~~

~~achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.2(c). The December 1 inventory level will be deemed to include: oil that the ISO determines was burned to produce electricity on and after November 15 of that year, including during an audit of dual fuel capability, provided that oil used in an audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.2.~~

~~(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:~~

~~*(Eligible Inventory x Set Rate) x Performance Adjustment*~~

~~Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K. 2(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. Performance Adjustment shall mean:~~

$$\cancel{\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}}$$

~~The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.~~

~~**III.K.3. Liquefied Natural Gas.**~~

~~Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of that winter.~~

~~(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving pipeline gas or supplies of liquefied natural gas.~~

~~(b) **Proposed Contracts.** In the notice specified in Section III.K.1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.3. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.3(c). The ISO will review the notices and inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.3(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a "first come/first served" basis and shall inform Generator Assets of their provisional acceptance by each October 15.~~

~~(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a "take-or-pay" construct; the volume specified by the Market Participant pursuant to Section III.K.3(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO's provisional acceptance will be withdrawn.~~

~~(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:~~

~~*(Unused Quantity x Set Rate) x Performance Adjustment*~~

~~Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. Performance Adjustment shall mean:~~

$$\frac{\text{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\text{(Total number of winter hours)}}$$

~~III.K.4. Demand Response Service.~~

~~All defined terms used in this Section III.K.4 shall have the same meanings as if the asset were a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.~~

~~Market Participants with an asset located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including an asset with behind-the-meter generation capable of reducing demand from the electric system and delivering any net supply, are eligible to participate pursuant to this Appendix K. Assets mapped to a Real-Time Demand Response Resource are eligible to participate, subject to the additional requirements specified below, and provided that the capacity supplied by these assets is in addition to the Capacity Supply Obligation, as of December 1 of the relevant Capacity Commitment Period, of the Real-Time Demand Response Resource to which the asset is mapped, and provided further that the prohibitions in Section III.E1.1.2 are not triggered.~~

~~Except for assets mapped to a Real-Time Demand Response Resource, an asset may consist of an aggregation of individual end-use facilities so long as those facilities are located within the same Dispatch Zone, and provided further that such aggregation does not result in a quantity of demand reduction and net supply of 5 MW or greater at a single Node.~~

~~The following asset types are not eligible to provide services under this Section III.K.4: (i) Real-Time Emergency Generation Assets; (ii) any asset that is dependent upon a non-firm or an additional supply of natural gas to produce demand reductions or net supply; and (iii) any asset that participates in the energy market pursuant to Section III.1 of the Tariff.~~

~~Each Market Participant that has an asset accepted by the ISO for this service is subject to the following additional requirements from the relevant December 1 through March 1:~~

(a) ~~**In service.** By December 1, participating assets must, in accordance with the existing requirements for Real-Time Demand Response Assets and Real-Time Emergency Generation~~

~~Assets: (i) be registered with the ISO; (ii) have meters installed and operational; (iii) have a valid Demand Response Baseline; (iv) have a Demand Designated Entity to which Dispatch Instructions are communicated; and (v) otherwise be fully ready to respond.~~

~~(b) **Size of Program and Assets.** Each participating asset shall provide at least 100 kW of capability. No more than 100 assets at a level not to exceed 100 MW shall be accepted by the ISO pursuant to this Appendix K.~~

~~(c) **Metering.**~~

~~i. Market Participants must meet the metering requirements specified in Appendix III.E and the ISO New England manuals, with the exception that 5-minute meter data does not have to be reported to the ISO in real time for assets not mapped to a Real-Time Demand Response Resource.~~

~~ii. To the extent that an asset consists of an aggregation of individual end-use facilities, Market Participants must submit a single set of interval meter data, as measured from each facility's Retail Delivery Point, representing the sum of the metered demand of the end-use facilities comprising the asset.~~

~~iii. Market Participants shall report meter data and may submit meter data corrections to the ISO using the Demand Response Market User Interface within 2.5 business days after the Operating Day.~~

~~iv. Meter data corrections may be submitted during the 70-day period beginning with the first of the month following the operating month. To the extent meter data affecting an asset's performance measurement and passing all quality checks has not been submitted by the initial settlement deadline (i.e., within 2.5 business days after the Operating Day), payments related to that asset shall be deferred to the resettlement process.~~

~~v. In the event that valid meter data affecting an asset's monthly performance measurement that passes all quality checks is not submitted by the end of the 70-day data correction limit, that asset's performance shall be deemed to be zero for the intervals for which the meter data did not pass all quality checks.~~

~~(d) **Dispatch.**~~

~~i. Assets must be available for dispatch in real time between hours ending 0600 and 2300 on all days.~~

~~ii. Each dispatch shall be for no more than six hours.~~

~~iii. There will be no more than two dispatches per asset per day.~~

~~iv. There shall be at least four hours between the end of one dispatch and the start time of another dispatch.~~

~~v. Assets will be dispatched by the ISO at its discretion prior to, or concurrent with, ISO New England Operating Procedure No. 4, Action 2. The ISO may aggregate assets into blocks and dispatch only those assets comprising the blocks.~~

~~vi. Each asset shall be required to respond to Dispatch Instructions no more than thirty times.~~

~~vii. The ISO will communicate Dispatch Instructions to the Demand Designated Entity specified by the Market Participant for each participating asset.~~

~~viii. Assets will be dispatched for their entire, committed MW quantity except in cases where such dispatch may cause or worsen a local reliability problem. The ISO may, upon notification to the Demand Designated Entity, exclude from dispatch assets located in a particular Dispatch Zone, and/or individual assets where the committed MW quantity is 5 MW or more.~~

~~ix. Except as outlined in viii. above, assets must produce the MW quantity accepted pursuant to this Appendix K within thirty minutes of the issuance of a Dispatch Instruction.~~

~~x. If assets mapped to a Real-Time Demand Response Resource are dispatched pursuant to this Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource, and the amount of demand reduction plus any net supply produced in that interval is less than the Real-Time Demand Response Resource's Capacity Supply Obligation plus the sum of the asset's committed MW quantity pursuant to Appendix K, the amount of demand reduction plus any net supply produced shall be credited first to the Real-Time Demand Response Resource's Capacity Supply Obligation and the~~

~~remainder shall be credited pro-rata to each asset with an obligation pursuant to Appendix K based on asset performance.~~

~~(e) **Acceptance Criteria.** Market Participants must indicate their commitment to provide this demand response service by providing the notice indicated in Section III.K.1(e). That notice must include: the name and other pertinent identifiers of the asset that the Market Participant is seeking to enroll, the asset's electrical location, the MW quantity of demand reduction and any net supply, as measured from the asset's Retail Delivery Point, that the asset is willing and able to produce in response to Dispatch Instructions, and the method(s) by which the demand reduction or any net supply would be produced. If the Market Participant has not yet identified all of the assets that will be recruited to meet the service requirements, the Market Participant shall provide a description of how it will meet the requirements, and provide the Dispatch Zone within which these assets will be located. If an asset specified in the notice consists of an aggregation of individual end-use facilities, the information shall be provided for each facility that is part of the aggregation. The ISO shall accept up to 100 qualified assets at a level not to exceed 100 MW from those Market Participants providing notice, based on:~~

~~i. The asset's proposed capacity;~~

~~ii. The asset's location relative to known constrained areas; and/or~~

~~iii. Any historic performance from the asset.~~

~~The ISO may accept or reject any and all assets proposed for participation.~~

~~(f) **Compensation.**~~

~~i. **Monthly Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall be compensated under this Appendix K through a monthly payment of the Set Rate multiplied by the average MW performance achieved by the asset in the month, provided that such MW performance shall not exceed 150% of the committed MW quantity. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If the asset was not dispatched or audited in the month of December, the payment for that asset for that month will be based on its average MW performance in response to dispatch (including a dispatch for an audit) in the following month. If an asset was not dispatched in January or February, but was dispatched or audited in a previous month, the~~

~~asset's payment for the month in which it was not dispatched will be based on its average MW performance in the most recent month in which the asset was dispatched or audited.~~

~~ii.~~ **~~Monthly Payment for Assets Mapped to a Real-Time Demand Response Resource.~~** ~~For each winter, the monthly payment for assets that are mapped to a Real-Time Demand Response Resource will be the Set Rate multiplied by the average MW performance achieved by the asset in the month not to exceed 100% of the committed MW quantity, and further multiplied by the Performance Factor. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If an asset is dispatched in a month pursuant to Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource to which it is mapped, a Performance Factor will be calculated as follows:~~

$$\cancel{\textit{Performance Factor} = \frac{\textit{(Average Hourly FCM Performance} - \textit{Average Hourly Dispatch MW)}}{\textit{Winter Obligation MW}}}$$

~~Average Hourly FCM Performance is the average hourly MW reduction amount (inclusive of any net supply) achieved during the month by the Real-Time Demand Response Resource to which the asset is mapped during dispatch or audit pursuant to Section III.13. Average Hourly Dispatch MW is the average hourly MW reduction amount (inclusive of any net supply) in the Dispatch Instructions issued during the month pursuant to Section III.13 to the Real-Time Demand Response Resource to which the asset is mapped, which would not exceed the resource's Capacity Supply Obligation. Winter Obligation MW is the committed quantity of the asset pursuant to Appendix K in MW. The Performance Factor shall not exceed 1.0. The Performance Factor for a month will apply to monthly payments in subsequent months during the term if, in those subsequent months, the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13. If the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13 in the month of December, an audit of the resource will be conducted in the month of January. The audit shall assess the resource's ability to meet its Capacity Supply Obligation plus the sum of the committed quantity pursuant to Appendix K for assets mapped to the resource. The Performance Factor calculated during this audit will be applied to the month of December.~~

~~iii. **Energy Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall also receive a monthly energy payment, as follows:~~

~~*Winter DR Program Energy Payment =*~~

~~*(MAX ($250/MWh, Zonal LMP) x MWh Delivered x 1.065) – E Payment*~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time and where the 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~iv. **Energy Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter during hours in which an asset is dispatched concurrently with the hours in which it receives a demand curtailment schedule or initiates a Real-Time demand reduction pursuant to Section III.E or with the dispatch of the Real-Time Demand Response Resource to which the asset is mapped, the Energy payment received by the asset pursuant to Section III.E or Section III.13.7.2.5.3 will be subtracted from the energy payment hereunder. The energy payment for these assets will be computed as follows:~~

~~*Winter DR Program Energy Payment =*~~

~~*MAX [(MAX ($250/MWh, Zonal LMP) x MWh Delivered) x 1.065 –*~~

~~*TDR Payment– E Payment, 0]*~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.4 during the hours of dispatch excluding any performance during the thirty-minute notification time. TDR Payment is the Energy payment received by the asset pursuant to Section III.13.7.2.5.3 or Section III.E. The 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E~~

~~Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~v. **Voluntary Performance.** If the ISO dispatches an asset more than thirty times, the asset's response to those dispatches is voluntary, and any performance by the asset in response to those dispatches would not be used to calculate the monthly payment for services under this Appendix K or to assess non-performance. However, any Energy provided by the asset in response to these dispatches would be compensated as described in the preceding paragraphs.~~

~~vi. **Non-Performance Charges.** The non-performance charges for assets providing the demand response services described in this Section III.K.4 shall be:~~

~~A. For failure to reach 75% performance: If the asset fails to achieve an average MW performance of at least 75% of the committed MW quantity in a month, the asset shall forfeit its monthly payment for that month and for any other month during the term for which such performance is utilized for settlement.~~

~~B. For failure to submit valid meter data: the provisions of Section III.K.4(c)(v) shall apply with regard to meter data deemed to be zero because of quality problems.~~

~~**III.K.5 Dual Fuel Commissioning Service.**~~

~~As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual-fuel capability.~~

~~(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.~~

~~(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the~~

~~compensation for which the Market Participant is eligible if it achieves dual-fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.~~

~~(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset: (i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.~~

~~(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.~~

~~(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November~~

~~15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.~~

~~(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(f) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(f) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).~~

~~(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:~~

~~*Monthly Compensation x the number of months between date of the breach and May 31, 2018*~~

~~Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.~~

~~III.K.6. Resource Auditing and Performance Monitoring.~~

~~Participating Generator Assets must report their usable oil inventory levels and remaining contracted liquefied natural gas volumes to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.~~

~~In each winter, Market Participants providing the demand response service described in Section III.K.4 shall be audited by the ISO in the month of January if the asset was not dispatched or audited prior to the scheduled audit. During the audit, the ISO shall dispatch the asset without prior notice and assess its performance during the sixty minutes immediately following the end of the thirty-minute notification time. The results of an audit will be treated and settled as though it were a dispatch to maintain thirty-minute Operating Reserve. Audits of assets mapped to Real-Time Demand Response Resources will be concurrent with audits of those resources. If a Real-Time Demand Response Resource with a Capacity Supply Obligation is dispatched or audited, the performance of any assets providing demand response service pursuant to this Appendix K that are mapped to that resource shall be excluded from the performance of the resource if the audit is used as a Demand Resource Commercial Operation Audit. The performance of assets dispatched or audited pursuant to this Appendix K shall be equal to the difference between the asset's adjusted Demand Response Baseline, determined pursuant to Section III.8A, and the asset's meter reading during the period of dispatch (after consideration of the thirty-minute notification time). For purposes of establishing, computing, and adjusting an asset's Demand Response Baseline, assets dispatched or audited pursuant to this Appendix K shall be treated like a dispatch or audit pursuant to Section III.13.~~

~~III.K.7. Settlements, Cost Allocation and Financial Assurance.~~

~~(a)~~ **~~Cost Allocation and Settlement~~**~~.~~

~~i. Compensation to Market Participants for services described in Sections III.K.2 and III.K.3 shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding (1) Real-Time Load Obligation associated with~~

~~Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with (1) Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. Payments shall be made to the Market Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected.~~

~~ii. The monthly compensation described in Section III.K.4(f)(i)-(ii) for the demand response services described in Section III.K.4 shall be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the compensation is earned, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. The hourly compensation described in Section III.K.4(f)(iii)-(iv) shall be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation for the hour in which the service was provided, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Payments shall be made to the Market Participants providing the services through the ISO's settlements system in the month after the ISO makes the collections referenced in the first two sentences of this paragraph.~~

~~iii. Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.~~

~~(b)~~ ~~**Allocation and Settlement of Non-Performance Charges.**~~ ~~All repayments required herein, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset~~

~~Related Demand Resources (pumps only) and (2) Real-Time Load Obligation contributions from Coordinated External Transactions. Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions.~~

~~(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to this Appendix K. shall result in a reduced refund pursuant to Section III.K.7(b) to Real-Time Load Obligation.~~

~~APPENDIX K, ATTACHMENT 1~~

~~CONTRACT CERTIFICATION~~

~~The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:~~

1. ~~Contracting parties:~~____
2. ~~Date of contract:~~____
3. ~~Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:~~____
4. ~~Maximum total volume available under the contract:~~____________________
5. ~~Contract term (date and years) (must span, at a minimum, December 1 through the end of February):~~____
6. ~~Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]~~
7. ~~Any contract terms that restrict when the supply may be taken by the Generator Asset:~~

   ____
8. ~~Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]~~
9. ~~Entity providing pipeline transportation:~~ ______________________________
10. ~~Confirmation that contract has a "take or pay" construct: [Confirmed]~~

~~[MARKET PARTICIPANT]~~

~~By:~~____________________
~~Name:~~
~~Title:~~
~~Date:~~

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource’s Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant’s or Non-Market Participant Transmission Customer’s total debt (including all current borrowings) divided by its total shareholders’ equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the

Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and

ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant’s energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the “Forward Energy Inventory Election”). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the “Forward LNG Inventory Election”). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

New England Governors, State Utility Regulators and Related Agencies*

Connecticut

The Honorable Ned Lamont
Office of the Governor
State Capitol
210 Capitol Ave.
Hartford, CT 06106
bob.clark@ct.gov

Connecticut Attorney General Office
55 Elm Street
Hartford, CT 06106
Seth.Hollander@ct.gov
Robert.Marconi@ct.gov

Connecticut Department of Energy and Environmental Protection
79 Elm Street
Hartford, CT 06106
steven.cadwallader@ct.gov
robert.luysterborghs@ct.gov

Connecticut Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051-2605
michael.coyle@ct.gov

Maine

The Honorable Janet Mills
One State House Station
Office of the Governor
Augusta, ME 04333-0001
angela.monroe@maine.gov
Jeremy.kennedy@maine.gov
Elise.baldacci@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
Maine.puc@maine.gov

Massachusetts

The Honorable Charles Baker
Office of the Governor
State House
Boston, MA 02133

Massachusetts Attorney General Office
One Ashburton Place
Boston, MA 02108
rebecca.tepper@state.ma.us

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
Nancy.Stevens@state.ma.us
morgane.treanton@state.ma.us
Lindsay.griffin@mass.gov

New Hampshire

The Honorable Chris Sununu
Office of the Governor
26 Capital Street
Concord NH 03301
Jared.chicoine@nh.gov

New Hampshire Public Utilities Commission
21 South Fruit Street, Ste. 10
Concord, NH 03301-2429
tom.frantz@puc.nh.gov
george.mccluskey@puc.nh.gov
F.Ross@puc.nh.gov
David.goyette@puc.nh.gov
RegionalEnergy@puc.nh.gov
kate.bailey@puc.nh.gov
amanda.noonan@puc.nh.gov

Rhode Island

The Honorable Gina Raimondo
Office of the Governor
82 Smith Street
Providence, RI 02903
Rosemary.powers@governor.ri.gov
carol.grant@energy.ri.gov
christopher.kearns@energy.ri.gov
nicholas.ucci@energy.ri.gov

New England Governors, State Utility Regulators and Related Agencies*

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
Margaret.curran@puc.ri.gov
todd.bianco@puc.ri.gov
Marion.Gold@puc.ri.gov

Vermont

The Honorable Phil Scott
Office of the Governor
109 State Street, Pavilion
Montpelier, VT 05609
jgibbs@vermont.gov

Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701
mary-jo.krolewski@vermont.gov
sarah.hofmann@vermont.gov

Vermont Department of Public Service
112 State Street, Drawer 20
Montpelier, VT 05620-2601
bill.jordan@vermont.gov
june.tierney@vermont.gov
Ed.McNamara@vermont.gov

New England Governors, Utility Regulatory and Related Agencies

Jay Lucey
Coalition of Northeastern Governors
400 North Capitol Street, NW
Washington, DC 20001
coneg@sso.org

Heather Hunt, Executive Director
New England States Committee on Electricity
655 Longmeadow Street
Longmeadow, MA 01106
HeatherHunt@nescoe.com
JasonMarshall@nescoe.com

Rachel Goldwasser, Executive Director
New England Conference of Public Utilities Commissioners
72 N. Main Street
Concord, NH 03301
rgoldwasser@necpuc.org

Mark Vannoy, President
New England Conference of Public Utilities Commissioners
18 State House Station
Augusta, ME 04333-0018
mark.vannoy@maine.gov